IGUA #4

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (i) to (vii) inclusive

Issue Number: 1.1 and 1.2
Issue: 1.1 What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

1.2 What is the method for incentive regulation that the Board should approve for each utility?

IGUA wishes to have PEG provide Schedules which will illustrate the incremental revenues, over and above the base year revenue requirement, which will be available to Union and EGD in an illustrative 1 % price cap scenario for Union and EGD for each of the years 2008 to 2012 inclusive.

For Union, please make the following assumptions:

- a 2007 rate base of$3.4B
- a composite depreciation rate of3%
- a 2007 revenue requirement, including cost of gas of $2B, with the delivery-related component thereof in an amount of $900M
- over the years 2008 to 2012 inclusive, the addition of20,000 residential customers per year

For EGD, please make the following assumptions:

- a 2007 rate base of$3.7B
- a composite depreciation rate of 4.5%
- a 2007 revenue requirement, including the cost of gas of $3.1B, with the delivery related revenue requirement component thereof being in an amount of $925M

Witness: Mark Lowry

- over the years 2008 to 20 I 2 inclusive, the addition of 50,000 residential customers per year

If further assumptions need to be made to provide the illustrations, then please have PEG make the further assumptions which it considers to be reasonable.

Under these assumptions, please provide exhibits which will show, for Union and EGD separately, the following:

a) The incremental revenues, over and above the base year revenue requirement, which a 1 % price cap for each of the years 2008 to 2012 will produce in each of those years;

b) The estimated amount of capital spending which the 1 % price cap will accommodate in each of the years 2008 to 2012 inclusive; and

c) For EGD, provide a schedule which will show the incremental revenues, over and above the base year revenue requirement, which EGD's proposed revenue per customer cap of2% per year will produce for each of the years 2008 to 2012 inclusive, along with the estimated amount of capital spending which EGD's revenue per customer cap of 2% per year will support in each of those years.

<u>RESPONSE</u>

PEG is not prepared to answer this question. The question is better directed to Union and Enbridge.

Witness: Mark Lowry

IGUA #5

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Staff Discussion Paper, Union Ex.B, Tab 1, Appendix A

Issue Nos.: **11.1, 11.2 and 11.3**

Issue:
11.1 What information should the Board consider and stakeholders be provided with during the IR plan?
11.2 What should be the frequency of the reporting requirements during the IR plan (e.g., quarterly, semi-annually or annually)?
11.3 What should be the process and the role of the Board and stakeholders?

IGUA wishes to obtain PEG's opinions on the appropriate reporting requirement features of an IR regime for Union and EGD. The quarterly surveillance reporting requirements which the National Energy Board ("NEB") follows are reflected in a copy of the year end quarterly surveillance report filed by TransCanada PipeLines Limited ("TCPL"). In the context of this attachment, please provide PEG's responses to the following questions:

(a) Please describe the extent to which U.S. utilities are subject to the same kind of surveillance reporting requirements which TCPL and other NEB regulated utilities are required to follow.

(b) What advice, if any, did PEG provide Board Staff with respect to the reporting requirements issue?

RESPONSE

a) PEG is not an expert on reporting requirements. We may note, however, that most gas utilities make detailed annual reports on their operations to state regulatory commissions. These reports are generally consistent with the Uniform System of Accounts that applies to Federal Energy Regulatory Commission Form 2.

b) We stated to Staff informally that utilities should file detailed annual reports based on a uniform system of accounts.

Witness: Mark Lowry

IGUA #6

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (i) to (vii) inclusive, Board Staff Discussion Paper
Issue Nos.: 12.1, 12.1.1 and 12.1.2
Issue: 12.1 Annual Adjustment
12.1.1 What should be the information requirements?
12.1.2 What should be the process, the timing, and the role of the stakeholders?

What are PEG's recommendations with respect to frequency with which changes should be made to rates on account of Y and Z factors?

RESPONSE

We believe that annual adjustments strike the right balance between the need for simplicity and the need to contain operating risk.

Witness: Mark Lowry

IGUA #7

INTERROGATORY

Ref: PEG Report, Executive Summary, pp. (i) to (viii) inclusive, and pp. 2 and following re: X factor components

Issue Nos.: 1.1 and 3.2

Issue: 1.1 What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

3.2 What are the appropriate components of an X factor?

The evidence indicates that the X factor is an offset to inflation in the adjustment formula to be applied to rates or to the revenue requirement of a particular utility. Consultatives with respect to the X factor issue have revealed that its statistically derived components are controversial and its judgmentally determined components are equally controversial. In this context, please provide responses to the following questions:

(a) Does a negative X factor imply negative productivity?

(b) Does PEG agree that regulators ought not to countenance negative productivity? Please include a brief rationale for PEG's response to this question.

(c) What simplified approaches to the X factor component of the adjustment mechanism did PEG consider? For example, did PEG consider the rate freeze approach or a percentage of inflation approach as simplified approaches to the adjustment mechanism? Please explain the extent to which simplified approaches were considered and the results of PEG's consideration of each approach considered.

RESPONSE

a) No. A negative X factor can in principle result from a combination of other circumstances. These might include rapid growth in the productivity of the economy (which reduces the productivity differential) and a negative input price differential.

Witness: Mark Lowry

b) Regulators can countenance negative productivity growth if it is the result of declining average use or other adverse operating conditions.

c) PEG is open to the use of simplified mechanisms in a final IR plan. However, they need to be just and reasonable. For example, a rate freeze or a percentage of inflation approach is just and reasonable only if it comports with expectations concerning utility unit cost trends. Input price and productivity research is often useful for demonstrating the reasonableness of simple mechanisms.

d) One final comment is that a percentage of inflation approach is equivalent to a price cap plan with an X factor that varies with inflation. We know of no reason for the X factor to vary in this fashion.

IGUA #9

INTERROGATORY

Ref:	PEG Report, Executive Summary, Board Staff Report	
Issue Nos.:	**5.1 and 5.2, 6.1 and 6.2, 9.1 and 9.2, 10.1 and 10.2**	
Issue:	**5.1**	**What are the Y factors that should be included in the IR plan?**
	5.2	**What are the criteria for disposition?**
	6.1	**What are the criteria for establishing Z factors that should be included in the IR plan?**
	6.2	**Should there be materiality tests, and if so, what should they be?**
	9.1	**Should an off-ramp be included in the IR plan?**
	9.2	**If so, what should be the parameters?**
	10.1	**Should an ESM be included in the IR plan?**
	10.2	**If so, what should be the parameters?**

IGUA is interested in obtaining PEG's views on matters pertaining to the appropriateness of including or excluding an Earnings Sharing Mechanism ("ESM") as a feature of an IR plan for Union and EGD. In this context, please provide PEG's responses to the following questions:

a) In PEG's view, does a regulator have a continuing obligation over the duration of an IR regime to monitor the rates being charged to assess whether they remain within just and reasonable limits and are not producing unreasonable returns for utility shareholders?
b) In PEG's view, is an ESM feature of an IR plan equivalent to treating a portion of equity return, in excess of the utility allowed return, as a Y factor or a Z factor adjustment to rates?
c) Is the excessive return "off-ramp" equivalent to a 100% ESM mechanism in favour of the ratepayers?

RESPONSE

a) Yes.

b) Yes.

Witness: Mark Lowry

c) No, since the utility still gets to keep surplus earnings up to the off ramp target.

IGUA #11

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 36
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

Union's evidence criticizes the PEG evidence with respect to service group PCIs. Please provide responses to the following questions with respect to Union's criticisms of PEG's evidence:

a) Please have PEG provide a list of each of the criticisms Union makes of PEG's evidence and a summary of PEG's response to each of those criticisms.

RESPONSE

1. "Union does not understand how the ADJ can be determined using PEG's approach without doing a productivity study by rate class".

The ADJ formula is based on the premise that there can exist hypothetically stand-alone gas utilities that specialize in the production of each group of services that is of interest (*e.g.* a utility that serves only residential customers). Utilities specializing in service to residential customers do not in fact exist (although utilities specializing in service to large volume customers do). However, the formula can nonetheless be implemented with data from utilities that, like Enbridge and Union, are integrated in the sense that they serve multiple groups. The results are valid to the extent that key calculations that are based on integrated utility data are reasonable *approximations* to the (unobtainable) calculations for hypothetical specialized utilities. Examining the ADJ formula on p. 96 of the June report we hope, for example, that the ratio of an integrated utility's revenue from service group l to its total base rate revenue is a reasonable approximation to the ratio of the revenue of a hypothetical specialized utility providing the same amount of service to group l to the sum of the revenues from specialized utilities serving all service groups (also in the same quantities).

Witness: Mark Lowry

2. Union also implicitly criticizes the PEG approach as being complex and inadequately intuitive.

The process of allocating costs and setting rates under conditions of declining average use is highly complex and can involve hundreds of pages of evidence. It should not be surprising, then, if an automatic and *rigorous* approach to do the same thing is also complex.

Regarding the intuition, PEG believes that it is quite intuitive that the trends in the rates for different service groups would differ based on differences in the ways that they change revenue and cost. A dramatic drop in the volume of any service would, for example, strand the cost of facilities used in its provision and result in a hike in its price under cost of service (COS) regulation. Similarly, an unusual surge in the demand for a service might require costly system expansions that cannot reasonably be shared with other customers under COS. The cost of a massive expansion in the power transmission system of Hydro One would not, for instance, be recovered in distribution rates. In the case of Enbridge and Union we find a combination of slow residential volume growth that disproportionately slows revenue and brisk customer growth that disproportionately increases cost. The proposed method can handle this less extreme case.

IGUA #13

INTERROGATORY

Ref: PEG Report
Issue No.: 10.1
Issue: Should an ESM be included in the IR plan?

The evidence indicates that the Price Cap Mechanism and Rate Cap Mechanism can be designed so that the expected benefits of improved performance are shared equitably between utilities and their customers:

a) Does PEG agree that implementation of an ESM is a method whereby the benefits of improved performance can be shared equitably between utilities and their customers? If not, why not?

b) Please set out the advantages and disadvantages of ESMs from the perspective of the shareholder and the customer.

c) Please provide copies of all research and presentations prepared by PEG that address ESMs in a North American setting.

RESPONSE

a) Yes.

b) Here are the salient advantages of ESMs as PEG sees them.

- Equitable sharing of the benefits of improved performance under IR plans is facilitated.
- Benefits are shared as they are realized; with less need for a stretch factor, speculation about future performance gains can play a diminished role in plan design.
- Reduces the likelihood of extreme earnings outcomes.
- Reduces utility operating risk.
- Encourages parties to agree to plans of longer duration

Here are the salient disadvantages.

Witness: Mark Lowry

- Performance incentives are weaker for plans of given duration. For example, a five year plan with an ESM has weaker incentives than a five year plan without one. There are thus fewer benefits from IR available for sharing between utilities and their customers.
- With ratepayers more exposed to the consequences of cross-subsidization, regulators will be less inclined to afford utilities greater marketing flexibility and other forms of operating flexibility. Large volume, with their greater elasticity of demand for utility services, can benefit materially from marketing flexibility.
- Consumers are disappointed if earnings do not reach the sharing range.
- Consumers absorb more of the risk of utility operation and, with a symmetric plan, can pay higher rates when earnings are low.

c) This is an onerous data request given the large volume of our published work on IR and a lack of great change in our view of ESMs over the years. We provide instead an article on IR labeled IGUA 13 Attachment that we wrote for the *Energy Law Journal* which contains a representative discussion of our views.

The working papers provided by PEG in our answer to Enbridge, Exhibit R-PEG Tab 3 Schedule 45 contain details of our recent incentive power research. A table in this package contains the results of runs with ESMs that illustrate their tendency to weaken performance incentives. Please note that access to the code supporting our incentive power model requires the signing of a confidentiality agreement.

Witness: Mark Lowry

PERFORMANCE-BASED REGULATION OF UTILITIES

Mark Newton Lowry, Ph.D.[*]
Lawrence Kaufmann, Ph.D.[*]

I. INTRODUCTION

Performance-based regulation (PBR) is an alternative to traditional cost of service regulation of energy utilities. In North America, PBR plans have been approved in such diverse jurisdictions as Alberta, California, Florida, Illinois, Maine, and Ontario. The Federal Energy Regulatory Commission (FERC) and Canada's National Energy Board (NEB) use PBR to regulate oil pipelines and some gas lines. The FERC has recently encouraged the use of PBR to regulate electric power transmission. Outside North America, PBR is now the standard form of investor-owned energy utility regulation. PBR is also extensively used in other regulated industries, most notably in telecommunications.

Despite the growing importance of PBR, the attention paid to it by economists is uneven. Several economists have addressed the incentive impacts of alternative regulatory systems using mathematical theory. Sophisticated cost research has been submitted as evidence in PBR proceedings. However, there has not to our knowledge been a scholarly and thorough non-technical review of PBR concepts and precedents serving as a reference for practitioners.

This paper is intended to fill this gap. While not all-inclusive, we believe this PBR survey is the most authoritative and complete to date. Information is presented on approved plans for energy utilities in North America, Great Britain, and Australia.[1] Analysis of plan design options is tendered reflecting the authors' practical experience.

The paper is structured as follows. Section II discusses criteria economists use to select among alternative regulatory regimes. Section III examines cost of service regulation and introduces the

* Mark Newton Lowry [B.A., M.A., and Ph.D. (Applied Economics) University of Wisconsin] and Lawrence Kaufmann [B.A. and M.A. University of Missouri, Ph.D. (Economics) University of Wisconsin] are Partners of Pacific Economics Group in Madison, WI.

1. PBR is also found in many countries with less advanced economies, including Argentina, Colombia, and Mexico. We confine our attention to PBR in advanced industrial countries to place a sensible limit on the scope of survey.

PBR alternative. Sections IV through VI explore the main approaches to PBR in greater detail. The approaches examined are rate and revenue caps and benchmark regulation. In each of these sections, the regulatory mechanism is described, precedents are detailed, and the merits of the approach are evaluated. Sections VII and VIII explore two important sets of plan provisions that must be addressed under all of the general approaches. These are benefit sharing and plan termination provisions. Important details of energy PBR plans approved to date are summarized in the Appendix. Citations are provided for specific plans discussed in the text.

II. CRITERIA FOR PLAN SELECTION

In appraising alternative approaches to rate regulation, it is useful to have clear evaluation criteria. This chapter presents criteria widely used by economists in policy analysis. In later sections, we assess different regulatory systems primarily on the basis of these criteria.

A. Efficiency

In the view of economists, there are two fundamental criteria for evaluating regulatory systems. One is economic efficiency. A regulatory system is economically efficient to the extent that it generates the maximum possible net economic benefits for society.

In appraising the efficiency of a regulatory regime, it is useful to recognize some major dimensions of efficiency. In this study, we separate efficiency into three components. These components are productive efficiency, allocative efficiency, and regulatory cost.

1. Productive Efficiency

Utility regulation encourages productive efficiency to the extent that it induces the subject utility to meet the demand for its products at minimum cost. In the short run, some inputs are "fixed" in the sense that adjustments in the amounts used are quite expensive. Automated meter reading equipment is an example. Introduction of such equipment may save cost over time, but it would not be cost effective to transform the entire metering system in one year. In the short run, productive efficiency depends on meeting demand with a minimum-cost mix of other, variable inputs. In the long run, all inputs are variable, and the cost-effective use of capital equipment is also a central efficiency concern.

2. Allocative Efficiency

Rate regulation encourages allocative efficiency to the extent that the value of service to the customers exceeds the cost of service provision.[2] A company's success in achieving this goal depends on its product development and marketing operations. In the short run, the adjustment in rates for existing services to reflect changing market conditions is the main allocative efficiency challenge. In the long run, the mix of services offered by a company becomes an important concern.

The allocative efficiency of a company's operations does not depend solely on "core" services offered to customers without competitive options. Companies may also be able to enhance welfare by meeting demands in more competitive markets. Involvement in competitive markets can spread the cost of inputs used to provide monopoly services across more output, thereby reducing unit costs for the range of products provided by the company. Competitive market involvement can also potentially increase the number and variety of products available to customers in these markets. This is especially attractive in markets, such as those for local telecommunications services, where additional competition is especially welcome.

Product quality is another important aspect of allocative efficiency. Customers have varied needs for quality. Competitive markets often feature an array of competing products with different price-quality attributes. Competition between firms and the consumers' ability to choose among alternatives is often sufficient to ensure that the quality of products available in the marketplace is appropriate.

The threat of lost business is weaker for utility companies than for other businesses where product quality is a vehicle for competition. In many cases, the local utility is a monopoly provider and stands to lose fewer sales than a similar competitive firm if service quality is off the mark. Since social benefits from regulation depend on both price and quality, the encouragement of appropriate quality levels is a proper regulatory objective.

3. Regulatory Cost

Costs are incurred in utility regulation. These include, most obviously, the resources (*e.g.* accountants, lawyers, and hearing rooms) of utilities, interveners, and government agencies dedi-

2. It should be noted that economists have used the term "allocative efficiency" in a number of ways. For example, allocative efficiency is sometimes defined so it includes using the optimal *mix* of production inputs for given levels of input prices, whereas productive efficiency pertains only to optimal input *levels*. We believe there is little practical value in making this distinction and include both types of decisions in the productive efficiency criterion. In our taxonomy, allocative efficiency applies to choices leading to an optimal allocation of goods in the marketplace given consumer demands. Our definition of allocative efficiency therefore applies to marketing as opposed to production decisions.

cated to the regulatory process. Senior company officials are also drawn into the regulatory arena. This can divert management attention from market developments and performance may suffer as a result. The reduction of regulatory cost is not an end in itself, but regulation is more efficient to the extent that it is not needlessly costly.

B. Fairness

A second fundamental criterion for appraising regulatory systems is fairness. This may be defined as the manner in which social benefits are divided among the stakeholders in the regulatory process. Customers and shareholders are the primary stakeholder groups. However, the division of net benefits among residential, industrial, and other customer sub-groups is also of concern.

Economic analysis can be used to assess the net social benefits from alternative regulatory systems. Distributional issues can also be analyzed. However, distributional criteria can rank regulatory systems only if there are weights for the welfare of different stakeholder groups. There is no objective basis for assigning these weights. For this and other reasons, economists have to date dwelled mainly on the efficiency of alternative regulatory systems.

III. THE REGULATORY CHALLENGE

A. Cost of Service Regulation

1. Description and Precedent

Cost of service regulation (COSR) is a convenient term for the common approach to regulation of investor-owned energy utilities in the United States.[3] Under this system, the rates approved by a commission are expected to recover the company's prudently incurred cost of providing regulated services. This cost includes a return on capital.[4] Rate cases are held occasionally in which estimates are made of the prudent cost of capital, labor, and other inputs used to provide regulated services. This becomes the base rate revenue requirement. The volatility of energy prices has prompted some regulators to provide for a shorter lag between the

3. The term "utility" is defined here and throughout this article to be an enterprise that provides essential services on a monopoly basis and, if private, is subject to rate and service regulation. As such, the term encompasses oil and gas transmission companies, electric utilities, and gas distributors.

4. This characterization of cost of service regulation is, of course, stylized. The terminology and precise procedure for setting rates varies considerably across regulated industries and regulatory jurisdictions.

purchase of energy inputs and the addition of these costs to the revenue requirement.

For both kinds of inputs, the determination of allowed cost is complicated if the utility company sells some products in unregulated markets. Almost every utility has some involvement in such markets. The rental of under utilized real estate is illustrative of such a market. To the extent a utility has such operations, its total cost will exceed the cost of regulated services and some share must be assigned to the regulated services.

Once the revenue requirement is determined, it is allocated for recovery from the various regulated services offered. The rate for a service is designed to recover this assigned cost given estimates of customer numbers, delivery volumes, and other billing determinants. The regulated service offerings and rate designs require commission approval. These terms are reviewed occasionally at the insistence of either the utility or the regulatory agency.

The determination of the revenue requirement and its allocation among customer groups is complicated by the common costs incurred jointly in the provision of various services. The inherently arbitrary nature of common cost allocations makes them a source of controversy in COSR.

2. Evaluation

COSR is widely suspected of failing to achieve the maximum net benefit to society that is possible from utility company operations. The heart of the problem is the high cost that must be incurred for regulators to acquire knowledge of utility operations. If they knew the efficient way to produce and market utility services, they could simply mandate the provision of the optimal services and set prices to recover the minimum cost of providing them. Unfortunately, it is often difficult, even for company managers, to recognize best practices given the substantial uncertainty that exists regarding future supply, demand, and policy conditions. The challenge is much greater for regulators since they are apt to have little direct experience with utility operation. Economists call this situation one of information asymmetry. A redressing of the informational asymmetry between company managers and regulators requires substantial data exchange, processing, and analysis.

Measures are naturally taken to contain these regulatory costs. Rate cases may occur less frequently than at annual intervals. When rates are reset, they may be based more on the company's unit cost than on external unit cost standards. One means of achieving this is to scale back on the prudence review process. Companies may be placed at significant risk only for actions with conspicuously unfortunate outcomes. Penalties may not be levied for failure to adopt the best or the most innovative practices. Rewards may not be considered for superior performance.

Regulatory cost can also be contained by restricting practices that complicate regulation. For example, service offerings may be limited and rate structures kept simple. Companies may be discouraged from engaging in novel or risky activities. Transactions with unregulated affiliates are a third common area of restriction. Such simplifications can reduce regulatory costs, but they can also diminish the productive and allocative efficiency of utility operations. If rate adjustments are based on the trend in the company's own unit cost, efforts to trim costs or improve the market responsiveness of rates and services lead eventually to lower rates. This weakens company performance incentives. Incentives are especially weak for performance initiatives involving upfront costs to achieve long term benefits. Another class of initiatives strongly discouraged is those involving a significant risk of conspicuous failure. This would presumably include many kinds of innovations.

Restrictions on utility operations can also reduce efficiency. For example, limited service offerings and inflexible rates hamper the utility's ability to satisfy its customers' complex and changing needs. The efficiency consequences of ineffective marketing are especially acute where demand is elastic with respect to rate and service offerings. These situations include services to customers with access to competitive service arrangements, including the ability to shift activities to sites served by other utilities. Incremental consumption of utility services is another important category since this may require a discount. A timely example is longer distance power transmission, which promotes the development of competitive power markets. A third important category is service to economically distressed customers. Unresponsive market offerings can lead to uneconomic bypass of the company's services. More typically, margins from services to markets with high demand elasticity will not be maximized, so that a larger share of the utility's cost must be recovered from other customers.

Restrictions on affiliate transactions can also reduce efficiency. Utility companies sometimes seek to achieve economies of scale and scope by moving operations to affiliates with the ability to serve competitive markets and the utility simultaneously. Under COSR, utility purchases of services from such affiliates can raise cross-subsidy concerns. Some regulators have responded to this challenge by discouraging affiliate transactions or placing onerous and intrusive restrictions on affiliate operations. These problems and the attendant regulatory costs may lead utility companies either to forgo competitive market involvement or to serve competitive markets through unregulated affiliates lacking the full potential benefits of scale and scope economies. Failures of unregulated affiliates of utilities are reported routinely in the trade press and some may be traced to this problem.

One economy measure that can increase the efficiency of COSR is a reduction in the frequency of rate cases. As the period between rate cases, sometimes called regulatory lag, increases, the length of time during which the company retains the benefits of performance improvements increases. Performance incentives are thereby strengthened, especially for projects involving up front costs to achieve long-term gains.

Extended regulatory lag is most feasible in periods of slow input price inflation, and when industries or individual companies are positioned to achieve rapid productivity growth. For example, extended lag has been feasible for many years in the telecommunications industry due to slow input price inflation and the exceptionally rapid productivity growth of that industry. The productivity growth prospects of an energy utility might improve temporarily due to a merger that accelerates scale economy realization.

Notwithstanding these situations, the potential for regulatory lag is limited in most energy utility industries. Prices of some utility inputs, like natural gas, are volatile. A failure to adjust rates for changes in the cost of these inputs would make earnings volatile and thereby raise the cost of capital. Another reason regulatory lag is limited is that in most utility industries, as in the economy as a whole, prices must trend upward in nominal terms to compensate utilities for unavoidable inflation in input prices. Infrequent rate cases are also less tenable during times of rapid industry change. Even if revenue requirements do not need to be adjusted, companies will want to modify their rate structures and service offerings in response to changing market conditions. The end result is that rate case cycles in utility industries typically do not exceed three years and annual rate cases are common. Regulatory lag is especially short for energy procurement activities.

In summary, there is a tradeoff in COSR between productive and allocative efficiency and the cost of regulation. Maximum productive and allocative efficiency can only be achieved at high regulatory cost. Many efforts to contain these costs impair these efficiencies.

B. The PBR Alternative

PBR is a general approach to utility rate regulation encompassing a wide range of mechanisms that can weaken the link between a utility's rates and its unit cost of service. To the extent that the goal is met, it is possible to attain higher levels of productive and allocative efficiency from a given level of regulatory cost. PBR can then be said to represent progress in "regulatory technology" that increases the size of the economic pie available for higher earnings and better terms of service.

There are several sources of this technological progress. First, PBR makes use of automatic rate adjustment mechanisms established in advance of their operation. Such mechanisms are often represented by mathematical formulas. The use of such mechanisms can reduce the frequency and scope of regulatory intervention. A second source of progress is that PBR mechanisms rely heavily on data that are external in the sense of being insensitive to the actions of utility managers. Data on the input price and productivity trends of other utilities are illustrative.

To the extent that rate adjustments are based on a combination of external data and automatic adjustment mechanisms, the regulatory system is externalized and utilities can be more confident that superior performance will not trigger changes in regulatory policies depriving shareholders of benefits. This process strengthens performance incentives and promotes the attainment of productive and allocative efficiency. In addition, lessened concern about cross subsidies and risky ventures makes it possible to accord utilities greater operating flexibility.

The use of economic research is a third source of progress. Theoretical and empirical research can be brought to bear on the appropriate combination of automatic mechanisms and external data. For example, research can be used to design a regulatory system that protects utilities from unavoidable input price fluctuations while ensuring customers the benefit of normal performance improvements.

The combined effect of these attributes is a regulatory process that, in spite of lower cost, can strengthen performance incentives and afford an increase in operating flexibility by making price restrictions less sensitive to company actions. The potential benefits from rate regulation are therefore increased and PBR plans can be designed so the benefits of performance improvements are shared between shareholders and customers.

A wide variety of mechanisms are available to craft PBR plans. These may usefully be grouped into basic approaches to PBR and other plan provisions that must be specified under various basic approaches. The basic approaches to PBR include rate caps, revenue caps, and benchmarking. Two important categories of other PBR tools are benefit sharing and plan termination provisions. We address each of these topics in the sections that follow.

C. Application: Energy Supply

The potential advantages of PBR may be clarified by discussing the challenge of regulating one important class of utility services, which is retail energy supply. We define retail energy supply as the business of securing supplies of gas or electric power for retail customers. Power supplies can, in principle, be obtained from power procurement or self generation.

The choice of this business to illustrate key concepts in our discussion may surprise some readers. After all, this business is widely considered to be potentially competitive, and thus, less appropriate for regulation than more natural monopolies like power distribution. However, electric utilities still monopolize power supply to retail customers in roughly half the North American markets. These markets include: Mexico, most of Canada, and the southeast, the mid-continent, the Rocky Mountain, and the northwest regions of the United States. There is, furthermore, no conspicuous move towards retail competition in these regions. Natural gas distributors, meanwhile, still monopolize about half of the retail North American gas supply market. Most gas and electric utilities subject to retail competition still provide default energy supply services subject to regulation.

Setting aside the desirability of monopolies on retail energy supply, it is noteworthy that the business is one of the more difficult to regulate using COSR. Since prices for power, natural gas, and other fuels are volatile, it is risky to fix charges for their procurement for extended periods. Many gas and electric utilities recover the cost of fuel and power procurement almost immediately. The resultant reduction in regulatory lag weakens performance incentives. Under COSR, this means an unusual reliance on prudence reviews to ensure that charges for energy supply are just and reasonable.

The risk of prudence disallowance in the energy supply business is substantial. A myriad of options is available to procure fuel and power and to deliver them to a utility's system. Supplies can, for instance, be purchased with varying degrees of reliability and price stability. For power suppliers, there is the added challenge of choosing between power purchases and the various technologies for self-generation. Additionally, given the volatility of energy prices, it is all too easy for a utility to make energy supply decisions that are later found to have been unfortunate.

There is no shortage of evidence of prudence risk in the energy supply business. In the 1980s and early 1990s, many electric utilities received prudence disallowances for building capital-intensive nuclear generation in an era of high capital costs and low energy prices. In the mid to late nineties, disparities between the average regulated cost of power supply and lower spot prices placed many utilities under the threat of stranded cost. More recently, some utilities have faced prudence reviews for excessive reliance on spot purchases of natural gas and power. The risk of prudence disallowance from inferior performance is generally not counterbalanced by the opportunity to profit from superior performance as it would in an unregulated market.

A further complication occurs where a company wishes to supply energy to a mix of competitive and monopoly markets. In that event, economies of scale and scope can often be realized by having a single enterprise serve both kinds of markets. For smaller utilities especially, a consolidated operation can be a key to competitive market success. One approach to consolidation is to have the utility make sizable sales of energy to competitive markets. This can raise complex issues about the sharing of cost and competitive market margins. Another approach is to place energy supply operations in an unregulated affiliate that sells energy to the utility. This raises the issue of fair transfer prices.

Our discussion suggests the energy supply business is unusually costly to regulate well using COSR. The high cost compels regulators to limit prudence vigilance and restrict operating practices that complicate review. In the aftermath of restructuring, for instance, California's power distributors were discouraged from employing hedging practices that might have stabilized the cost of power procured for default customers. Considering additionally the typically short regulatory lag for fuel and power purchases, the end result is that regulation of energy supply using COSR can involve weak performance incentives and extensive operating restrictions. These problems help to explain why this sector has produced some of the more impressive failures of North American regulation.

PBR has significant advantages in the regulation of energy supply. By weakening the link between a utility's charges for energy supply and its own cost, it can strengthen incentives for efficient operation, improve the risk return balance, and facilitate relaxation of operating restrictions. Stronger incentives permit economies in the prudence review process. Intelligent use of economic reason and empirical research can reduce the risk of energy supply PBR. An example is the careful use of data on energy market price trends.

Given these advantages, it is not surprising that PBR is used fairly extensively in energy supply regulation today. Its use is especially common in regulation of natural gas procurement by distributors. Plans have been approved for more than a dozen distributors, including Avista (Idaho, Or., Wash.), Northern Illinois Gas (Ill.), and Southern California Gas (Cal.). In approving PBR plans for gas procurement, regulators in both California and Illinois have portrayed PBR as an alternative to detailed prudence reviews. In approving the Avista plan in Oregon, regulators expressly acknowledged an intent to facilitate gas purchases from an unregulated affiliate.

To date, PBR has not made significant inroads into the regulation of default power procurement services by distributors. Instead, utilities have generally chosen conservative procurement strategies that minimize risk of a prudence disallowance. A PBR settlement agreement proposed by San Diego Gas and Electric was rejected by the California Commission.[5] The company was subsequently subject to a review of its purchasing practices. PBR is used for bundled power service in many states that have not elected to pursue retail competition. Pricing energy purchases from unregulated affiliates using competitive bidding is not typically viewed as PBR, but is very consistent with PBR principles.

IV. RATE-CAPS

Rate caps are the most common form of PBR in the world today. This section addresses the rate-cap approach. Discussions of procedures and important issues in plan design are followed by an evaluation of the approach.

A. Overview

Under a rate-cap plan, restrictions are placed on the terms of certain regulated services. Restrictions commonly take the form of limits on rate escalation. The limits are called caps since utilities are often free to charge rates that are less than the maximum allowed.

The mechanisms for determining allowed rate growth vary, but all have the attribute of being external. The simplest approach is to hold rates constant for the plan duration, which is sometimes called a rate freeze or moratorium. A simple variant of the rate freeze is a set of pre-scheduled rate adjustments, which may be increases or decreases.

Still another approach is to limit rate adjustments using indexes. Under this approach, growth in baskets of the utility's prices may be measured using actual price indexes (APIs). Growth in each API is limited using a price cap index (PCI).[6]

B. Precedents

1. United States

Extended periods of operation without rate cases have been achieved at one time or another by many utilities. These sometimes result from commitments to rate freezes. The rate freeze approach has been especially common in telecommunications.

Many energy utilities that have operated under rate freezes do not perceive this form of regulation as PBR. However, several

5. Protest of Utility Consumers' Action Network to SDG&E's Application to Change Electric Rates Pursuant to Full Collection of Competition Transition Costs, No. 99-02-029 (Cal. P.U.C. 1999).

6. The useful acronyms API and PCI appear to have developed in U.S. Federal Communications Commission proceedings.

companies have in recent years chosen rate freezes as key components of a PBR package. Noteworthy in this regard are plans for bundled power services of AmerenUE (Mo.), Black Hills Power & Light (S.D.), and Edison Sault Electric (Mich.); for the power distribution services of National Grid in Massachusetts and New York; and for the gas distribution services of Consumers Energy (Mich.) and Michigan Consolidated Gas (Mich.). The Michigan plans are especially interesting as they applied to both the gas supply and delivery services of the companies. The rate moratorium for International Transmission Company (ITC) is also of interest as the first PBR plan for unbundled power transmission approved by the FERC.[7] This plan will take effect, however, only if ITC joins a regional transmission organization and is sold to a company that is not a market participant.

The first large scale rate indexing plan in the United States was that for Class I line haul railroads under the terms of the Staggers Rail Act of 1980.[8] Rate indexing has since been used extensively in U.S. telecommunications. The Federal Communications Commission (FCC) played a leadership role in this regard, approving price cap plans for AT&T in 1989 and for interstate services of local exchange carriers (LECs) in 1991.[9] Rate indexing is now widely used in state-level telecom regulation.

Rate indexing has been used to regulate several U.S. energy utilities. Federally regulated services of U.S. oil pipelines are subject to rate indexing. A rate-indexing plan has also been approved by the FERC for Transwestern Pipeline Company, a natural gas pipeline.

The first rate indexing plan approved for a U.S. electric utility was for the bundled power services of PacifiCorp (Cal.). Since then, plans have been approved for the bundled power service of Central Maine Power (Me.), the power distribution services of Bangor Hydro Electric (Me.), Central Maine Power (Me.), National Grid (Mass.), SDG&E (Cal.), and Southern California Edison (Cal.), and for the gas delivery services of Bangor Gas (Me.), Boston Gas (Mass.), and SDG&E (Cal.).[10]

2. Canada

Rate indexing in Canada began in the telecommunications industry. The Canadian Radio-Television and Telecommunications Commission (CRTC) approved a plan that applies to nearly all

7. *International Transmission Co.*, 92 F.E.R.C. ¶ 61, 276 (2000).

8. Staggers Rail Act of 1980, Pub. L. No. 96-448, 94 Stat. 1895 (1980) [hereinafter Staggers Act].

9. Policy and Rules Concerning Rates for Dominant Carriers, F.C.C. 89-314, No. 87-313 (proposed May 8, 1989) (codified at 47 C.F.R. pts. 61, 65, 69).

10. The plan for National Grid (Mass.) involves a rate freeze and rate indexing.

telecom utilities in the country.[11] Rate indexing has also found favor with regulators in Ontario. Rate-cap plans have been approved there for the distribution services of Ontario power distributors and Union Gas.

3. Britain

Rate indexing has been extensively used by regulators in Britain. It was first applied to British Telecom in 1984. Since then, rate indexing has been applied to electric, gas, and water utilities.

4. Australia

Rate indexing is also common in Australian regulation. The country's telecommunications industry has been under "price controls" since 1989. Power distribution rates for utilities in the states of New South Wales and Victoria are also subject to indexing.

C. The PCI Formula

Price cap indexes are determined by mathematical formulas. While the formulas vary from plan to plan, it is generally true that the PCI growth rate (ΔPCI) is the difference between an inflation factor (P) and an X-factor (X), plus or minus a Z-factor (Z).[12] The standard formula may be stated succinctly as

$$\Delta PCI = P - X \pm Z.$$

We consider each of the formula components in turn.

1. The Inflation Measure

The inflation factor, P, is the growth rate in an external price inflation measure. Three basic kinds of measures have been used in approved rate-cap plans. These may be constructively described as macroeconomic, industry-specific, and peer price measures.

Macroeconomic inflation measures are summary measures of growth in the prices of a wide range of the economy's goods and services. Those used in PBR plans are typically computed by government agencies. Examples include the chain-weighted price in-

11. Price Cap Regulation and Related Issues, Telecom Decision, C.R.T.C. 97-9 (1997) [hereinafter Telecom Decision].

12. The term Z-factor appears to have developed in the FCC proceeding to develop a price cap plan for AT&T. It was so called because the PCI for AT&T also included an X-factor as here described and a "Y" factor to effect a specific category of price cap adjustments.

dex for gross domestic product (GDPPI), consumer price indexes (CPIs), and producer price indexes (PPIs). Macroeconomic measures are almost universally used in telecom utilities' rate-cap plans. They are also the most common measures in plans for energy utilities outside North America. Indexes of consumer price inflation are used in most overseas indexing plans.

An important advantage of macroeconomic inflation measures is their simplicity. They also have credibility, since they are computed with some care by government agencies. The main concern with macroeconomic inflation measures is their ability to track growth in the prices of utility inputs.

Industry-specific inflation measures are expressly designed to track inflation in the prices of the relevant utility inputs. Such measures summarize the growth in sub-indexes that are chosen to track trends in the prices of major input categories. The index formula customarily assigns weights to the sub-index growth rates that reflect the shares of the input categories in utility cost. Cost share weighting is a method of developing a summary inflation measure which reflects the impact of input price growth on cost.

An industry-specific inflation measure was first used in the indexing plan for U.S. railroads.[13] It was first approved in the U.S. energy industry for the bundled power services of PacifiCorp (Cal.). This precedent is of added importance because the California Public Utilities Commission staff played an instrumental role in the index design. Industry-specific inflation measures have since been approved for the gas delivery services of Southern California Gas (Cal.), the gas and electric power delivery services of SDG&E (Cal.), and the power distribution services of Ontario utilities.

The inflation measure in San Diego's PCI for power distribution merits description as an example of the genre. It features sub-indexes for three input categories: capital services, labor services, and miscellaneous operation and maintenance (O&M) inputs. The weights assigned to the sub-indexes are the shares of each input group in the distribution cost of California investor-owned utilities calculated over a recent five-year period. Here are the sub-indexes and the corresponding cost shares:

13. The inflation measure in the railroad indexing plan is a weighted average of the growth rates in external indexes of the prices of railroad inputs, including labor, fuel, materials, equipment rentals, depreciation, interest, and miscellaneous inputs. Each input is assigned a weight that reflects its share of the total cost of the railroad industry.

Input Category	Inflation Subindex and Sources	Cost Shares
Capital Services	Rental price of electric distribution utility plant, Data Resources International (DRI), and Whitman, Requardt, and Associates.	.576
Labor Services	Average hourly earnings for electric, gas and sanitary workers, U.S. Bureau of Labor Statistics.	.179
Non-Labor O&M	Weighted average of cost indexes for five distribution input categories, DRI Utility Cost Information Service.	.245

The heavy weight assigned to the capital services price sub-index means that the company is well protected from change in the cost of funds.

By design, an industry-specific inflation measure tracks industry input price fluctuations better than an economy-wide measure. An industry-specific inflation measure can thus do a better job of reducing business risk. This advantage is important because the input price growth of a utility industry can differ considerably from that of the economy in the short run. For example, bundled power service is intensive in the use of both energy and capital. It therefore merits an inflation measure that is more sensitive to trends in fuel and power prices than macroeconomic measures. Energy transmission and distribution are unusually capital intensive businesses. The reduction in business risk from the use of an industry-specific input price index can make possible an extension of the plan term and the avoidance of alternative risk mitigation mechanisms that are more likely to weaken performance incentives.

One disadvantage of the industry-specific approach is its complexity. Another is that no official source computes input price indexes for energy utilities. On the other hand, the construction of accurate indexes is aided by well-established theory and publicly-available data.

An interesting issue in considering industry-specific inflation measures is their effect on regulatory risk. Industry-specific measures can help sidestep controversy over adjustments otherwise needed to a PCI featuring a macroeconomic inflation measure to help it better track industry input price trends. On the other hand, approved industry-specific measures may not do the best possible job of tracking industry input price inflation. A good example is the measure approved in Ontario for power distribution, which de-emphasized capital price escalation in a way that slowed PCI growth in the name of PCI stabilization.

Peer price indexes are indexes of the prices charged by other service providers. A peer price index for the bundled power service of a midwestern utility might, for example, be constructed from the retail price trends of other midwestern utilities. A major appeal of these indexes is that they embody the input price and productivity trends of the industry and therefore permit an avoidance of controversy over how these trends should be measured. In North America, it is presently difficult to regulate most transmission and distribution services using peer price indexes due to the lack of unbundled price data on the services. However, the availability of data should improve as competition proceeds.

2. The X-Factor

The X-factor is an external parameter in the PCI formula that typically causes the PCI to grow more slowly than the inflation measure, to the benefit of customers. Thus, prices for regulated services are likely to decline in real terms. X is sometimes called a "productivity factor" since considerations of productivity growth are sometimes involved explicitly in choosing its value.

Various methods have been used to ensure the external character of X. Most commonly, its value in each year of the plan is set in advance and is constant throughout the plan. However, in several approved plans, the X-factors are set in advance, but scheduled to vary from year to year. For example, X-factors have been scheduled to rise gradually over the term of the plan. X may also be recomputed periodically to reflect new information as long as the computation formula is insensitive to the actions of subject utility managers. The best known precedent for this approach is the X-factor in the indexing plan for U.S. railroads.[14] This was an annually updated rolling average of the recent productivity growth of the railroad industry.

3. The Z-Factor

The Z-factor term of a PCI adjusts the allowed rate of price escalation for external developments that are not reflected in the inflation and X-factors. It is apt to differ from period to period. One of the primary rationales underlying Z-factor adjustments is the need to adjust price limits for the effect of changes in tax rates and other government policies (*e.g.*, conductor undergrounding requirements and policies promoting energy conservation) on the company's unit cost. Absent such adjustments, policymakers can

14. This is discussed in more detail *infra* Part IV.*D*.3.

adopt new policies that increase the company's unit cost, confident in the knowledge that earnings, rather than rates, will be affected. Another rationale for Z-factors is to adjust for the effect of other miscellaneous external developments on industry unit costs that are not captured by the inflation and X-factors. An advantage of Z-factors is that they reduce risk without weakening performance incentives. A disadvantage is that they can significantly raise regulatory cost.

D. The American Approach to PCI Design

At present, two countries have extensive experience with price cap regulation: the United States and Great Britain. Each country has its own approach to PCI design, and the methodologies differ greatly. In general, the differences between the British and American approaches to PCI design are poorly understood on both sides of the Atlantic.

1. The American Approach

Although rate indexing is associated in the minds of many with Great Britain, North America actually has a longer history with this regulatory system. E. Fred Sudit of Rutgers University outlined the approach to PCI design that has become common in North America in a 1979 paper.[15] William Baumol, then at Princeton University, elaborated on the idea in a 1982 paper.[16] These early treatises influenced the American approach to PCI design, but credit must also go to other individuals who were involved in the early regulatory proceedings and supporting legislation.

2. Index Logic

The founding principle of PCI design in North America is that indexes should simulate the workings of competitive markets. The logic of economic indexes yields information about competitive markets that can be used to implement this principle. A central result of index logic is that if an industry earns a competitive rate of return in the long-run, the long-run growth trend in an index of the prices that it charges (its output prices) will equal the trend in its unit cost index.

$$\textit{Trend Output Prices}^{\textit{Industry}} = \textit{Trend Unit Cost}^{\textit{Industry}} \qquad (1)$$

15. E. Fred Sudit, *Automatic Rate Adjustments Based on Total Factor Productivity Performance in Public Utility Regulation*, *in* PROBLEMS IN PUBLIC UTILITY ECONOMICS AND REGULATION 55 (Michael A. Crew ed., Lexington Books 1979).

16. William J. Baumol, *Productivity Incentive Clauses and Rate Adjustment for Inflation*, PUB. UTIL. FORTNIGHTLY, July 22, 1982, at 11.

The unit cost of an industry is its cost per unit of output.

In a competitive market, maximum prices reflect industry conditions and each individual supplier keeps all of the after-tax benefits accruing from its efforts to slow its own unit cost growth. This creates strong incentives for suppliers to contain unit cost growth. Competition ensures that slower growth in an industry's unit cost leads eventually to slower growth in the prices that it charges.

A price cap plan can simulate these competitive market conditions. Actual price indexes can measure the growth in a utility's prices for services offered on a non-competitive basis. The growth in the APIs can then be limited by PCIs that track the unit cost trend of the relevant utility industry.

A PCI conforming to the following formula reflects the industry unit cost trend:

$$Trend\ PCI = Trend\ Unit\ Cost^{Industry} \qquad (2)$$

Conformance can be achieved when the PCI tracks either the *annual* fluctuations in the unit cost of an industry or the industry's longer run unit cost *trend*. Each approach has advantages and disadvantages. The unit cost of an industry can be volatile from year to year due to input price fluctuations or to a temporary slackening or strengthening of market conditions. Unit cost responds to input prices in much the same manner as output prices do, but responds differently to demand fluctuations. For example, a slackening of demand typically lowers prices but raises unit cost. Thus, linking the PCI to annual industry unit cost fluctuations honors the competitive market standard only in the long run. Another problem with a short-term annual approach is that often the data needed to calculate industry unit cost trends accurately are not available in a timely fashion. For example, the final data needed to calculate the cost of power distribution nationwide in 2002 is not available until the middle of 2003, when the FERC Form 1 reports are due. Delays for gas distribution data are even longer.

A PCI that is calibrated to reflect only the industry's long-run unit cost trend can mitigate these problems. However, in times of input price volatility, the long-run approach may subject utilities to undue financial distress and send the wrong price signals to customers. Rapid price inflation occurs periodically in the U.S. economy and is even more common abroad.

A second result of indexing logic further facilitates the design of a PCI that honors the competitive market standard. The trend in an industry's unit cost index can be shown to be the difference between the trends in its input price and total factor productivity (TFP) indexes.

$$Trend\ Unit\ Cost^{Industry} = Trend\ Input\ Prices^{Industry} - Trend\ TFP^{Industry} \quad (3)$$

The TFP index of an industry captures the wide range of developments that can cause its unit cost to grow at a different rate than its input prices. These developments include technological progress and the realization of scale economies. TFP is volatile but typically trends upward, so that an industry's unit cost grows more slowly than its input prices over time.

Our discussion suggests that a PCI can honor the competitive market standard by conforming to the following formula:

$$\begin{aligned} Trend\ PCI &= Trend\ Input\ Prices^{Industry} - Trend\ TFP^{Industry} \\ &= Trend\ Input\ Prices^{Industry} - X \qquad (4) \end{aligned}$$

This formula has two terms: the industry's input price index and an X-factor. The X-factor is calibrated to reflect the industry's long-run TFP trend.

One practical advantage of this formula is that data on price trends are available in a more timely fashion than data on industry TFP trends. It is thus possible to have an inflation measure that reflects the latest developments, while the X-factor reflects only long-term TFP trends. Having X reflect the long-run TFP trend sidesteps the need for more timely data and avoids annual TFP calculations. It also smoothes the effect on unit cost of short-run demand shifts.

Now let us consider the implications of using a macroeconomic inflation measure in lieu of an industry-specific measure. Suppose, for example, that the GDPPI is used as the inflation measure. Index logic implies that the trend in a PCI that honors the competitive market standard should then conform to the following formula.[17]

$$\begin{aligned} Trend PCI = Trend\ GDPPI - [(Trend TFP^{Industry} - Trend TFP^{Economy}) \\ + (Trend Input Prices^{Economy} - Trend Input\ Prices^{Industry})] \quad (5) \\ = Trend GDPPI - X \end{aligned}$$

The X-factor in this case contains multiple terms. One is the difference between the TFP trends of the industry and the economy, which is sometimes called the "TFP differential." The second

17. The economy can reasonably be expected to earn, in the long run, a competitive return. Indexing logic then suggests that the input price inflation of the economy exceeds GDPPI inflation by the economy's TFP growth.

term is the difference between the input price trends of the economy and the industry, which is sometimes called the "inflation differential." X is larger, slowing PCI growth; the larger are both terms.

Even when developing a PCI that uses a macroeconomic inflation measure, the issue of whether short-term or longer term trends should be tracked remains relevant. It is customary for the inflation measure to track recent trends and for the TFP differential to track long-term trends. The practice regarding the inflation differential is less established. Inflation in the input prices of the economy and capital-intensive industries like energy distribution can differ substantially in the short-term and medium-term, so an inflation differential that reflects more recent historical differences can lead to an unusually high or low X-factor. Unfortunately, the trend in the recent past may not be a good indicator of the trend during the PBR plan. In the past twenty years, for example, the trend in the input price index of the U.S. economy has, by some measures, been more rapid than the trend for capital-intensive industries like energy distribution due to a secular decline in interest rates. Information from input price forecasts, however, suggests that any such differential is unlikely to continue.

Although an extreme value for the inflation differential is attractive to the benefiting party, either customers or shareholders, it is apt to lead to considerable X-factor volatility down the road. The injured party will inevitably suspect that the rules for X-factor calibration will be revised before X would be allowed to swing sharply in the opposite direction. One means of resolving this problem is to base the inflation differentials on inflation trends in the very long run, such as over a thirty-year period. Another is to base it on input price forecasts.

3. Early History

The earliest use of this index logic emerged from hearings before U.S. federal regulatory commissions. As early as 1980, the Interstate Commerce Commission (ICC) proposed to determine allowable increases in rail freight rates using the average increase in rail carrier costs.[18] The Staggers Rail Act of 1980 was noted above to require index-based regulation for larger railroads. The law established a Zone of Rate freedom for certain rail services. Under section 203 of the Act, the boundary of this zone was to be adjusted each quarter by an "Index of Railroad Cost . . . compiled or verified by the Commission, with appropriate adjustments to reflect the changing composition of railroad costs, including the

18. Railroad Cost Recovery Procedures, 49 CFR §1135.1 (Aug. 22, 2002).

quality and mix of material and labor . . . ."[19] The growth rate of this index came to be called the Rail Cost Adjustment Factor (RCAF).

There was vigorous and protracted debate before the ICC regarding the appropriate form of this index. The most fundamental issue was whether the index should reflect the trend in the TFP of the industry as well as the input price trend. An index reflecting both would track the unit cost of the industry, as noted above.

In 1989, the ICC concluded that the index should reflect the TFP trend of the railroad industry as well as its input price trend.[20] The X-factor it adopted is a moving average of the growth rate in an index of railroad industry TFP, as noted above. The index measured the productivity of the very companies that were subject to the PBR plan. The staff of the Surface Transportation Board, successor to the ICC, now computes the index. However, the plan is no longer operative since the railroads have exercised options contained in the plan to exit it.

The Federal Communications Commission (FCC) has issued landmark decisions on PCI design that are broadly consistent with the principles established in the railroad case. In approving the price cap plan for AT&T in 1989,[21] inflation measures and industry TFP trends were discussed extensively.[22] The X-factor reflected the industry productivity trend and an inflation measure adjustment.

In approving rate indexing for the interstate services of LECs, the need to calibrate the PCI to the industry unit cost standard was explicitly recognized. For example, in a 1995 order dealing with the PCI for LECs, the FCC states that "[t]he indexes are adjusted each year in accordance with a formula that accounts for industry-wide changes in unit costs."[23]

Since the approval of the first plans at the federal level, rate-cap plans have been adopted by a number of other regulatory commissions. The industry unit cost standard is frequently observed in PCI design. Commissions sometimes recognize the standard explicitly. Thus the Massachusetts Department of Public Utilities (DPU), in approving a rate-cap plan for NYNEX, notes that, "price cap regulation replaces company- specific, test year cost-based control of a firm's rates with an index representing the

19. Staggers Act, *supra* note 8, § 203(a)(2)(B) at 1901.

20. Railroad Cost Recovery Procedures-Productivity Adjustment, 5 I.C.C.2d 434 (1989).

21. *In re* Policy and Rules Concerning Rates for Dominant Carriers, CC No. 87-313 (1989) (codified at 47 C.F.R. pts. 61, 65, 69).

22. The affected rates of AT&T were subsequently decontrolled.

23. *In re* Price Cap Performance for Local Exchange Carriers, 10 F.C.C. Rcd 8961, 8965 (1995).

expected changes in costs for the average firm in the industry."[24]

The California Public Utilities Commission states, in approving the rate-cap plan for Southern California Edison, that:

> [T]he price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its own cost and productivity . . . The productivity measure should come from a forecast of industry-specific productivity.[25]

In Canada, the Canadian Radio and Telecommunications Commission (CRTC) has also subscribed to the industry unit cost standard. In its order approving the rate-cap plan for the Stentor Companies, the CRTC states that, "the price cap formula is composed of three basic components which, in total, reflect changes in the industry's long-run unit costs."[26]

4. Total Factor Productivity (TFP)

The TFP index of a utility industry is the ratio of its output and input quantity indexes.[27] The output quantity index measures the trend in the amount of work performed by the industry. The output of energy distributors, for instance, will typically grow with the number of customers served. An input quantity index measures the trend in the amounts of labor and capital services and other inputs used to provide service. The growth in the TFP index is then the difference between the growth rates of the output and input quantity indexes.[28] TFP grows if output growth exceeds input growth.

A representative study of industry TFP trends was recently filed by Bangor Hydro-Electric in support of a proposed PBR plan. The primary source of the data for the study was the FERC Form 1, which every major investor-owned electric utility in the United States is required to file annually. The U.S. Energy Information Administration (EIA) has published selected Form 1 data for several years in a document series currently entitled *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*. Research data were also obtained from the U.S. Department of Commerce and Whitman, Requardt, and Associates.

24. New England Tel. & Tel. Co., Mass. D.P.U. 94-50, 45 (1995).

25. *Re* Southern Cal. Edison Co., 172 P.U.R.4th 393, 402 (Cal. P.U.C. 1996).

26. Telecom Decision, *supra* note 11, at ¶ 29.

27. All indexes in this discussion are assumed to measure trends in the values of economic variables over time.

28. Equation 3 above implies that TFP growth can also be calculated as the rate at which input price growth exceeds unit cost growth.

The data was used to calculate the TFP trend of the northeast power distribution industry. Two definitions of the northeast were considered: (1) New England and (2) New England plus New York. The sample period was 1988-1999.

The following table presents the 1989-1999 growth trends in the power distribution TFP indexes computed for the northeast, as well as the multi-factor productivity index for the U.S. private business sector over a similar period. It can be seen that the 0.63% growth trend in the TFP of New England power distributors was similar to that for the private business sector. The trend in the TFP of New England and New York distributors combined was somewhat slower.

TFP Trends for Power Delivery Services and the U.S. Economy, 1988-99

	Average Annual TFP Growth Rate 1988-1999
Northeast Power Distribution	
New England	0.63%
New England + New York	0.34%
U.S. Private Business Sector	
Non Farm	0.69%
Total	0.81%

These figures have important implications for energy distribution regulation. One is that X-factors can reasonably be expected to be much higher in telecom than in power distribution price cap plans. The current TFP trend for telecom utilities is more than two hundred basis points higher than that for power distributors. It should not be surprising, then, to find approved telecommunications price cap plans with X-factors at least two hundred basis points above those in approved power distribution plans.

These productivity figures also help to explain why multi-year rate freezes may not financially stress telecom utilities as much as they do power distributors. Telecom utilities typically face input price growth of 2% to 3% per annum. Given a similar TFP growth trend, indexing logic suggests that telecom utilities have recently experienced steady or moderately declining unit costs. On the other hand, while power distributors face an input price growth trend broadly similar to that of telecom utilities, their TFP growth is much slower, so that input price growth is more likely to exceed TFP growth, and their unit cost is more likely to rise over time.

Many distributors will therefore have difficulty remaining financially viable for an extended period of time without nominal rate increases. An American-style PCI could address this situation by allowing utility rates to rise moderately each year in nominal terms to keep pace with industry unit cost growth. The fact that utility prices are apt to rise in nominal terms should by itself cause no more concern than in competitive sectors of the economy.

E. The British Approach to PCI Design

The British approach to PCI design is that typical of utility rate regulation in Great Britain. Most British utilities were formerly public enterprises. In 1984, British Telecom (BT) was the first utility to be privatized. Since then, privatization has extended to the nation's electric, gas, and water utilities.

The decision to use rate indexing in British utility regulation was strongly influenced by the recommendations of Stephen Littlechild of the University of Birmingham. In a report released in 1983, he proposed to adjust BT's rates using an index with a growth rate formula of "RPI-X" form.[29] The RPI term is the inflation in the Retail Price Index, which is Britain's consumer price index. A specific value for X was not recommended, nor was there significant discussion in Littlechild's paper of the appropriate framework to be used to determine X. Rather, the value for X was described as "a number to be negotiated."[30] The lack of a well-defined framework has given British regulators considerable discretion in determining X-factors. Over time, however, broadly similar approaches have developed for the energy utility industries.

Under "British-style" rate indexing, rate cases are held at regular intervals that usually last five years. The rate case involves multi-year cost forecasts. The principle "building blocks" of the total cost forecast are the forecasts of the value of the current capital stock and of capital spending, depreciation, the return on capital, and O&M spending. A macroeconomic inflation index such as Britain's RPI is used as the inflation measure of the price cap index. Given the forecasts of total cost, billing determinants, and the RPI, it is possible to choose a combination of initial rates and an X-factor such that forecasted revenue equals forecasted cost.

This procedure might be characterized as five-year cost of service regulation in which indexing is used only to increase regulatory lag. However, British regulators have made increasing use of

29. Stephen C. Littlechild, Regulation of British Telecommunications' Profitability: Report to the Secretary of State (London: Dept. of Industry, 1983).

30. *Id*.

statistical benchmarking to further externalize regulation. In the case of power distribution, for instance, statistical methods are used to compare the efficiency of British distributors. The results of these studies have a bearing on the allowed cost of service.[31] The use of benchmarking in Britain has proven more complicated for industries, like power and gas transmission, in which the only available peers are in other countries.

F. *Price Caps and Marketing Flexibility*

A major attraction of price cap plans is the potential for enhanced marketing flexibility. As discussed in subsection 2 *infra*, price caps can enhance the marketing freedom of a utility since the allowed escalation in rates for regulated services is determined by an external mechanism. This reduces potential concerns with cross-subsidization that result when a utility's own unit cost data are used to set prices. Utilities can benefit from greater marketing freedom to enhance the market responsiveness of rate and service offerings. Fewer marketing restrictions also allow diversification projects to be pursued in the most cost-effective manner, either through the utility or affiliated companies. The amount of marketing flexibility afforded by a price cap plan depends greatly on the details of the plan.

1. Automatic Rate Redesign and Rebalancing

The rates that most American utilities charge are inconsistent with the known structure of their cost. This is especially true of the power transmission services and power and gas distribution services that have only recently been unbundled. Quite often, rates for energy distribution could be made more efficient by raising customer charges relative to usage charges and by implementing usage charges that reflect the time of use.

Although restructuring proceedings provide an opportunity to get rates for wires and pipe services "right," practical considerations can prevent this from happening. An abrupt change in the design of rates may be undesirable. A detailed review of rate design considerations may also be a relatively low priority as the parties to the proceeding grapple with more pressing restructuring issues. The design of rates may redistribute cost responsibility in ways that are politically unpopular.

A rate-cap plan makes it possible to redesign rates for utility

31. Statistical benchmarking is also used increasingly in North American PBR. An early use of benchmarking methods was in the PBR proceeding leading to the rate-cap plan for Boston Gas. The company used the results of benchmarking to argue against the addition of an "accumulated inefficiencies factor" to the X-factor. The Ontario Energy Board is currently considering the integration of benchmarking methods into its PBR procedures.

services gradually and automatically. The API that is capped can summarize the overall escalation in the prices of a service basket and adjustments in individual rate elements need not be restricted.[32] If an API for an energy distribution service is allowed to rise by 2%, for instance, it might be possible to raise the customer charge more rapidly than this so long as the volumetric charge rose less rapidly.

Some regulators may want to limit these rate design freedoms. In the case of energy distribution, a common concern is that higher customer charges can disadvantage small-volume customers. In such a case, regulators may place side conditions on allowed changes in certain rates or rate elements in order to protect certain customers or customer classes. For example, customer charges could be limited to the growth in the PCI plus 5%.

A related source of marketing flexibility is rate rebalancing. Rebalancing occurs when some service prices grow more rapidly than the PCI and other service prices grow less rapidly. However, as with rate redesign, regulators may want to restrict rebalancing in order to protect the interests of affected customer groups. Rebalancing can be controlled with side conditions that limit the growth in prices for particular services. Rebalancing can also be controlled by reducing the scope of baskets. The potential to rebalance rates is effectively eliminated when each service constitutes a separate basket. The lesson to be learned is that an indexing plan provides a ready vehicle for controlling the amount of rebalancing that occurs.

2. Optional Rates and Services

A second source of market flexibility under rate-cap regulation is the introduction of optional rates and services. These can be subject to light-handed regulation or, in the extreme, decontrolled. Several kinds of optional offerings may reasonably be considered such as: optional tariffs for regulated services, new services, unusually complex service packages, or services to competitive markets. Economists studying price cap regulation have found that it can substantially mitigate the cross-subsidy concerns that these offerings raise under COSR. This is because prices charged are not linked directly to costs, and utilities have no incentive to manipulate cost allocations in a manner that cre-

32. Utilities can choose from among a number of alternative methods for computing the API of a particular service basket. Important criteria to use when selecting an appropriate API calculation methodology may include: 1) ease of computation; 2) the extent to which the API accurately measures the change in customer welfare from utility pricing policy; and 3) the extent to which a particular API method gives companies "credit" for discounts that may be allowed under the plan (discounts generally receive more weight in API calculations when the index accounts for consumption increases that result from price declines).

ates cross subsidies.[33]

G. Evaluation

Rate caps can generate utility performance incentives much stronger than those obtained under typical cost of service regulation. One reason is that incentives are comprehensive so that a wide range of cost containment, product development, and marketing initiatives are encouraged. Another is that indexing can facilitate an extension of the period between rate cases. To the extent that this is true, improved unit cost performance does not reduce allowed price escalation. The benefits of improved performance can thus go straight to the bottom line.[34] The potential impact on productive and allocative efficiency is substantial. The actual incentive effects of rate caps depend greatly on plan details. For example, incentives increase with the length of the indexing period and with the introduction of post plan sharing provisions.

Rate caps can provide a further boost to efficiency by permitting a relaxation of operating restrictions. The case of marketing flexibility is illustrative. To the extent that rate restrictions are external, customers of monopoly services can be insulated from the effects of a company's operations in competitive markets. This reduces concerns about cross subsidization. Light-handed regulation of utility rates for non-core services is then possible. A company can also have more leeway in its purchases from affiliates and its depreciation practices.

Rate caps also facilitate rate redesign. As noted above, a wide range of rate element adjustments is consistent with a given rate of allowed price increase. A company will typically use these freedoms to move usage charges downward in the direction of marginal cost. The consequence should be a boost in usage and a reduction in the risk of volume fluctuations.

Rate caps can reduce regulatory cost. Some startup costs must, of course, be incurred to master the new regulatory system. These may include a close monitoring of the company's operations during the terms of the first indexing plans. But the frequency of future rate cases can be substantially reduced. Furthermore, reliance on external indexes diffuses inherently controversial cost allocation and transfer pricing issues. On the other hand, controversy can be considerable over alternative methods for measuring input price and productivity growth.

The numerous inherent advantages of rate caps are offset to some degree by disadvantages. One is regulatory risk. In this

33. Ronald R. Brauetigam & John C. Panzar, *Diversification Incentives Under "Price-Based" and "Cost-Based" Regulation*, 20 RAND J. OF ECON. 373 (1989).

34. Central Maine Power executives have noted the striking effects of price caps on performance incentives and corporate culture in a series of public appearances.

paper we have described two sensible approaches to PCI design that should mitigate regulatory risk. However, the novelty of rate indexing still invites regulators to choose important plan terms arbitrarily. These reduce the willingness of parties to try the rate-indexing option and can weaken the incentive benefits of price cap plans substantially. A rate freeze is a sensible alternative to indexing in jurisdictions where this is a concern but is not suitable in all times and places, as has been noted.

Rate caps also involve business risk such as the possibility that price restrictions will not track trends in external business conditions that affect a company's unit cost. Relevant business conditions include weather, the business cycle, prices of competing energy products, and government policy. Windfall gains and losses may occur if the PCI does not reflect changes in these conditions.

Business risks can be mitigated through careful plan design and empirical research supporting key plan parameters. For example, an industry-specific inflation measure will track fluctuations in input prices better than a macroeconomic measure. An X-factor based on a regional rather than a national TFP trend may better reflect local economic activity. The Z-factor should reflect changes in government policy as noted earlier. An earnings-sharing mechanism can also mitigate business risk, as we discuss further below. However, some windfalls may occur even if the plan is well supported and designed. Ironically, this is another way in which rate-cap plans mimic competitive markets.

V. REVENUE CAPS

A. *Comprehensive Revenue Caps*

1. Description

Under a comprehensive revenue cap it is the revenue of the company and not its rates that is the focus of restriction. Service offerings and the fashioning of rates from revenue can, in fact, continue using traditional methods. The addition of a balancing account mechanism can ensure that actual revenues are similar or equal to the revenue requirement. The balancing account contains the value of any mismatch between actual revenue and the revenue requirement until rates can be adjusted to eliminate it. This is sometimes called a revenue-decoupling mechanism since it severs the link between revenue and efforts to market regulated services.[35]

35. Decoupling mechanisms have also been used in the absence of indexing. Prominent examples include the electric revenue adjustment mechanisms that have

The growth of allowed revenue is usually limited using an index. The index formulas commonly feature an inflation measure, an X-factor, and a Z-factor. As with rate caps, the indexes can be designed using either an American or British approach.

Compared with the rate indexing formula presented earlier, a growth rate formula for a revenue cap index requires some adjustment to reflect the effect of output growth on cost. An explicit term for such an adjustment may be called an output factor, which is denoted by *Y*. An index-based restriction on revenue requirement growth may then be written:

$$\Delta \textit{ Revenue Requirement} = \mathrm{P} - \mathrm{X} + \mathrm{Y} \pm \mathrm{Z}\ .$$

The X and Y terms, as here described, are sometimes captured in a consolidated X. If *X* happens to be similar to the expected growth of output (*i.e.*, $Y = X$), the formula can be simplified to:

$$\Delta \textit{ Revenue Requirement} = P \pm Z\ .$$

Some revenue cap indexes therefore do not contain X or Y factors.

Because of these practices, X-factors from revenue cap plans must be used carefully in plan comparisons. Some plans restrict growth in revenue per customer. This is equivalent to revenue requirement indexing where the growth rate in the number of customers is the output factor.

2. Precedents

a. United States

A revenue per customer indexing plan has been approved for the gas delivery services of Southern California Gas (Cal.). The company had proposed price caps but a revenue cap was deemed more consistent with its previous regulatory commitments. A comprehensive revenue cap plan began in 1998 for the power distribution services of PacifiCorp in Oregon. The X-factor in this plan emerged from negotiations. Energy conservation was an especially important issue in the evolution of this plan.

b. Canada

The NEB of Canada has approved comprehensive revenue caps for two oil pipelines, Enbridge Pipelines (formerly Interprovincial Pipe Line) and TransMountain Pipe Line. Plans for

been used in California and Maine.

both companies resulted from settlement agreements. There is no evidence that industry unit cost trends were explicitly considered.

c. Britain

The power transmission services of National Grid have been subject to revenue caps since 1993. All regulated transmission services were originally subject to revenue caps. System operation services were exempted from revenue caps at the most recent plan update.

d. Australia

Revenue requirement indexing has also been approved for the power transmission services of Energy Australia, Powerlink Queensland, and Trans Grid in Australia. The inflation factors in all of these plans are consumer price indexes. Plan updates have been fashioned in the British style. The current X-factor for TransGrid is designed to compensate the utility for exceptional capital expenditures that are anticipated in the development of a national energy market.

3. Evaluation

Comprehensive revenue caps can create strong incentives for cost containment by permitting operation for an extended period with an externalized revenue requirement. The extent of externalization depends on other plan provisions, including those for benefit sharing and plan termination. There are incentives for a wide range of cost containment initiatives. The external basis for the revenue cap also encourages some forms of operating flexibility. For example, extended utility operation under a revenue cap could permit a regulator to relax its concern about the terms of purchases from an unregulated affiliate.

The main difference between the consequences of rate and revenue indexing lies in the area of allocative efficiency. One reason is that revenue caps focus on an incorrect measure of consumer welfare. Consumer welfare is properly measured as "consumer surplus," or the difference between the value received and the expenditure on a product. Consumer surplus always increases when prices decline, but this is not always true for lower customer bills (equal to total company revenues when summed over all customers) because the quantities purchased may, for whatever reason, be less. When the demand for a good is elastic, price declines lead to increases in both consumer surplus and total expenditures on the product. Revenue cap regulation therefore focuses on a variable (the sum of customer bills) that is fundamentally flawed as a welfare measure. In contrast, price cap regulation controls the escalation in utility prices and hence has a direct link to the welfare of utility customers.

A company is apt to continue facing restrictions on the development of market responsive rates and services. If the plan includes a revenue decoupling mechanism, incentives for an improved marketing performance will also be compromised. Marketing incentives may, in fact, be weaker than under cost of service regulation. For example, reducing volumetric charges in the direction of marginal cost will, by raising total revenue, promptly lower rates.

Revenue indexing can raise more concerns than rate caps about the quality of utility services. As with rate caps, service quality may suffer because there are strong incentives to cut costs. While the pressures to minimize costs are the same under rate and revenue caps, under the latter approach, revenues that are lost if poor service leads to fewer sales can be recovered through price increases on remaining customers using the balancing account. Since this is not possible under rate caps, the incentives to maintain service quality are weaker in the absence of counterbalancing incentive provisions.

Revenue indexing that is tied to a revenue decoupling mechanism reduces windfall gains and losses from demand fluctuations. This stabilizes company earnings and can thereby lower capital cost, but in the process, it destabilizes rates. For example, a recession in the service territory can place upward pressure on rates.

Another important attribute of decoupling is its ability to strengthen incentives to promote energy conservation. Conservation is an important goal in some jurisdictions. However, there are other methods for promoting energy conservation. One possibility is appending a targeted benchmark incentive for demand-side management to a comprehensive price cap plan. The costs of this program can be collected via a Z-factor. Such an incentive mechanism can be used to achieve conservation objectives without having the same implications for allocative efficiency as revenue caps.

Consideration may be finally paid to the issue of regulatory cost. Revenue indexing can permit economies in the cost of regulation relative to the cost of service approach. However, regulatory cost is likely to be somewhat greater than under rate indexing. The main reason is the continued need to approve the allocation of revenue requirements between customer groups, service offerings, and rate design.

B. Non-Comprehensive Revenue Caps

1. Basics

Under non-comprehensive revenue caps there are caps on only a portion of the company's rates or revenue requirement. An example might be a cap on the revenue requirement (allowed cost) for O&M expenses. As with comprehensive revenue caps, partial caps are usually fashioned using indexes. In the event of indexing, an adjustment for output quantity growth is once again needed. Partial indexing plans typically do not address rate and service offerings. Utilities therefore typically require authority outside of partial rates and revenue caps to alter these offerings. Design of a partial revenue cap index involves the usual choices of an inflation measure, X-factor, and Z-factor. The inflation measure in a revenue cap index for energy procurement would presumably be sensitive to changes in energy prices.

2. Precedents

a. United States

An important early example of non-comprehensive revenue caps is the first PBR plan for San Diego Gas and Electric. This plan, which applied to both gas and electric services, was approved in 1994. It has been claimed that the term "performance based ratemaking" was coined by San Diego personnel during this plan's development.

The plan included index-based adjustments for revenue requirements corresponding to allowed O&M expenses and capital spending. Separate O&M indexing mechanisms were specified for gas and electric operations. The mechanisms included inflation factors, X-factors, and adjustments for output growth.

b. Canada

Non-comprehensive revenue caps have been more widely used in Canada than in the United States. BC Gas began operating under caps for certain categories of base rate revenue in 1994. The caps pertained to O&M expenses and small capital expenditures. BC Gas also operates under a revenue decoupling mechanism called the Revenue Stabilization Adjustment Mechanism. It applies only to revenues from residential and commercial sales.

The NEB approved a non-comprehensive revenue cap plan for gas transmission services for Westcoast Energy in 1996. Indexing limited growth in the revenue requirement components covering O&M expenses and small capital additions. The formula for growth in both revenue cap indexes was forecasted inflation in a CPI. There were no explicit X or output factors in the formula.

The Alberta commission has approved non-comprehensive revenue caps for NOVA Gas Transmission. The caps apply to O&M expenses and small capital additions. A plan was approved for the gas delivery O&M expenses of Toronto-based Consumers Gas in 1998.

3. Evaluation

Non-comprehensive revenue caps can substantially externalize revenue requirements in the targeted areas. The full degree of externalization depends on other plan provisions, including plan termination and benefit sharing measures. The approach can focus management attention on specific problems and help accelerate their rectification. A partial indexing approach is also useful where there is consensus only on PBR for certain areas of the company's business. If the scope of regulation is changing, for instance, plans may be designed to focus only on areas subject to continuing regulation.

Non-comprehensive revenue caps can also permit increased operating flexibility in some areas. Suppose, by way of example, that a utility wishes to play an asset manager role and purchase numerous O&M services from unregulated affiliates. A cap on allowed O&M expenses can then permit relaxed vigilance on service transfers without placing recovery of capital cost at risk.

One potential problem with partial revenue caps is the unevenness of performance incentives. There will, at a minimum, be no special incentives to market or to control cost in non-targeted areas. At worst, the company may be given an incentive to improve performance in the targeted areas at the expense of performance in other areas. If a utility were subject only to a cap on O&M revenue, for instance, excessive capital spending could be undertaken to reduce O&M expenses. Overall, the company's performance might not improve.

This problem is mitigated to the extent that the partial caps cover most areas of controllable cost. For example, plans covering both O&M expenditures and capital expenditures have been defended on the grounds that they cover all "controllable" costs. However, plans approved to date have typically not extended to major capital additions.

By itself, partial indexing also does not improve allocative efficiency relative to cost of service regulation. As noted above, partial indexing approaches do not typically provide for the pricing and marketing flexibility that is helpful in achieving allocative efficiency. Partial indexing also does not create strong incentives for aggressive product development and marketing.

VI. BENCHMARK REGULATION

A. Benchmarking Basics

Benchmark regulation involves the evaluation of one or more indicators of company activity using external performance standards (benchmarks). The standards are external to the extent that they are insensitive to the actions of subject utility managers. Evaluations and rate adjustments are accomplished by formal mechanisms that are established in advance of use and typically function for several years.

The key features of a benchmark plan are the performance indicators, the performance benchmarks, and the rate adjustment mechanism. The performance indicators used in approved benchmark plans vary greatly in scope. Plans are comprehensive to the extent that they cover all of the utility performance dimensions that matter to customers.

The performance benchmarks used in benchmark plans are also varied. A common benchmark is a company's activity level in a period just prior to plan commencement. A company is rewarded for improvement in its performance relative to recent history.

An alternative approach, which is an example of "yardstick regulation" or statistical benchmarking, is to use the corresponding performance indicator of a group of utilities. Under this approach, a company is rewarded for improving its performance indicator relative to the group. The utility group is sometimes called a peer group, but can consist of all utilities in the same region as the company subject to the plan. In that event, the peer group may be viewed as a proxy for the regional industry. In principle, the region can also be the entire nation.

The rate adjustment mechanisms in approved benchmark plans vary. A major design issue is the customer sharing percentage. The mechanism may or may not feature a deadband in which deviations from the benchmark do not induce rate adjustments.

Benchmarking plans provide supplemental adjustments to rates rather than serving as the sole basis for rate adjustment restrictions. Several rate adjustment mechanisms can, in principle, coincide with a benchmarking plan. At one extreme, rates may be adjusted for the actual trend in a company's unit cost. At the other, rates may be predetermined for several years.

B. Comprehensive Benchmark Regulation

1. Description

A comprehensive benchmark plan is one in which benchmarking mechanisms cover substantially all facets of company performance that matter to customers. Comprehensiveness can be achieved by having a large number of indicators that cover separate performance dimensions, or by having a small number of broadly focused indicators.

Retail price indexes, unit cost indexes, and TFP indexes are examples of broad-based performance indicators. A basic unit cost index is the ratio of total utility cost to a utility output quantity index. Unit cost indexes can also rigorously incorporate additional utility performance dimensions that may influence customer welfare. These include service quality, environmental degradation, and the promotion of conservation. Conceptually, a benchmark plan with such a "master index" can be separated into a plan with a set of consistent non-comprehensive performance variables and associated weights. Decomposing a master index in this manner does not affect its incentive properties.

The following two relations detail an interesting example of the relationship between the award mechanism and the primary rate adjustment mechanism:

$$\Delta PNDX^{award} = \alpha \cdot (\Delta UCNDX^{external} - \Delta UCNDX^{company})$$

$$0 \leq \alpha \leq 1.$$

Here $\Delta PNDX^{award}$ is the adjustment in the utility's output price escalation due to the award. It is proportional to the difference between the growth rates in $UCNDX^{external}$ (a unit cost index benchmark) and in the unit cost index of the company. The award rate, α, may assume a value between zero and unity. Thus, it determines the share of the measured performance improvement that is kept by the utility. If $\alpha = 1$, the utility keeps all of the benefits of improving its performance relative to the unit cost benchmark. If $\alpha = 0$, the utility keeps none of the benefits.

Assume, now, that other than the award mechanism, the escalation in a company's rates is approximately equal to the growth in its unit cost index. The escalation in a company's price index is then given by:

$$\begin{aligned}\Delta PNDX^{company} &\cong \Delta UCNDX^{company} + \alpha \cdot (\Delta UCNDX^{external} - \Delta UCNDX^{company}) \\ &\cong \alpha \cdot \Delta \cdot UCNDX^{external} + (1-\alpha) \cdot \Delta \cdot UCNDX^{company}.\end{aligned}$$

It can be seen that the allowed inflation in a company's output price index ($PNDX^{company.}$) is approximated by a weighted average of the inflation in its unit cost index and in the external unit cost standard. The weights assigned to each category depend on the award rate. If $\alpha = 0$, inflation in the output price index is approximated by the inflation in a company's unit cost index. This may be termed "cost plus" regulation. If $\alpha = 1$, output price escalation is approximated by the growth in the external unit cost standard. This is a form of rate indexing.

The plan described in these relations therefore places a utility on a continuum between a variant of cost of service regulation (one without prudence reviews) and a variant of index-based regulation ("pure" price caps without discounting). That is, comprehensive benchmark regulation provides an opportunity to move "part way" towards rate indexing.

2. Precedents

a. United States

Several comprehensive benchmark incentive plans have been approved for U.S. energy utilities. Included are plans for Mississippi Power, Niagara Mohawk Power, Northern States Power, and Otter Tail Power. All of the plans involve multiple performance indicators. The Mississippi Power plan is noteworthy for being an early and influential example of the genre. The Niagara Mohawk plan is noteworthy for using unit cost indexes for other gas and electric utilities as benchmarks for evaluating the company's unit cost performance. This was an early formal use of statistical benchmarking in U.S. regulation.

b. Canada

A plan for West Kootenay Power was approved in 1996. Benchmarks were developed for a sizable number of narrowly defined cost categories. Different inflation measures, X-factors, and output factors were used to construct the benchmarks. An Incentive Adjustment Mechanism reduced business risk by sharing differences between Target Cost and Actual Cost with customers.

3. Evaluation

Comprehensive benchmarking has the potential to strengthen utility performance incentives relative to cost of service regulation with short rate case cycles. Incentives are potentially balanced and comprehensive so that companies are guided to pursue the most promising of a wide range of performance improvements. For instance, companies can work to beat a unit cost or productivity benchmark through old-fashioned cost cutting or aggressive marketing to boost the usage of system capacity.

Comprehensive benchmarking can also help to extend the period between rate cases by sharing deviations of actual performance from targeted performance using an automatic mechanism. This reduces regulatory and business risk in a manner that may predispose interested parties to agree on longer periods between plan reviews. The reduction in risk is, of course, valuable in its own right.

The actual effects of comprehensive benchmarking on performance incentives depend on plan details. The other provisions for rate adjustments are especially crucial. Incentives are weakened to the extent that other rate adjustment provisions involve regulator discretion. This is because regulators with discretion can respond to large performance awards by taking a tough line on other rate adjustments. A company will view this as an expropriation of benefits with disincentive consequences. Another plan detail with important incentive consequences is the share of the benefits of improved performance that is due to customers. Incentives weaken as the customer share rises. However, incentives can be strengthened relative to cost of service regulation if the benchmarking plan permits an extension of the period between rate cases.

We should also consider the extent to which comprehensive benchmarking can reduce regulatory cost and ease inefficient restrictions on operating flexibility. The sharing of performance gains under a benchmarking mechanism can raise awkward issues of cost allocation and transfer pricing. Resolving these issues can raise regulatory cost and may lead to operating restrictions. Comprehensive benchmarking also does not, by itself, allow for rate redesign or the introduction of new rates and services.

C. Service Quality Benchmarking

1. Description

Service quality is becoming an important issue in utility regulation. A report issued by North American regulators states that "[a]ttention to service quality will be of greater importance as competitive markets proliferate and financial regulation diminishes."[36] Service quality incentives designed to maintain or improve the quality of utility services can be either a stand-alone PBR application or a component of broader PBR packages.

A service quality incentive mechanism is a form of benchmark PBR which rewards or penalizes a utility depending on the relationship between its measured quality of service and quality benchmarks. There are three basic elements in a service quality

36. THE NATIONAL REGULATORY RESEARCH INSTITUTE, MISSIONS, STRATEGIES, AND IMPLEMENTATION STEPS FOR STATE PUBLIC UTILITY COMMISSIONS IN THE YEAR 2000: PROCEEDINGS OF THE NARUC 95-8 (NRRI 1995).

incentive plan: a series of indicators of the company's quality of service, an associated set of quality benchmarks, and an award mechanism that leads to changes in utility rates or allowed returns. The indicators are measurable service quality dimensions. The benchmarks are the standards against which the indicators are judged. They can be based on the company's historical performance, industry norms, or levels that are deemed to be acceptable for other reasons. An award mechanism determines the adjustment in rates that is warranted by the change in service quality. Important design issues include the symmetry of awards and penalties, and the customers' valuation of specific quality indicators.

A critical issue in the development of an effective service quality incentive plan is the choice of indicators on which performance will be judged. Ideally, individual quality indicators should satisfy three criteria: 1) they should be related to the relevant aspects of service; 2) they should focus on monopoly services; and 3) they should cover all major quality dimensions.

First, since measured service quality can ultimately affect customer rates, indicators should be linked to aspects of utility service that customers actually value. This may seem obvious, but a strict application of this criteria excludes indicators that have been included in some plans. For instance, the knowledge and courtesy of phone center employees may be a legitimate quality indicator, but the goal of establishing worker training programs to build these skills is not. By the same token, quality indicators should depend on quality *per se* and not on other aspects of distribution service. This has implications for the appropriate use of customer satisfaction surveys, since expressed satisfaction levels can depend on the perceived fairness of prices. In the case of power distribution, satisfaction can even depend on competitive transition charges and prices in the bulk power market. If survey results reflect price perceptions, they may create a kind of "double counting" of warranted price changes and, therefore, be inappropriate for use in incentive plans.

Second, indicators should focus on the quality of the activities for which there are few, if any, alternative suppliers. This is consistent with the principle that regulation, including regulation of service quality, is less necessary in competitive markets. Market forces are likely to create acceptable quality levels when products are available from multiple providers.

Third, quality indicators should not focus on some areas while ignoring others because performance may deteriorate in the non-targeted areas. Comprehensiveness can be achieved simply by adding indicators to a plan. However, regulatory costs often rise accordingly since more utility and commission resources must be devoted to quality monitoring and measurement of quality indicators. Some commissions have been sensitized to the regulatory costs of complex service quality plans. In these jurisdictions, service quality incentives have been simplified by relying on fewer, but more broadly-based, indicators.[37] While the specific indicators may vary widely among approved service quality incentive plans, there are broad similarities between the types of indicators used for energy utilities. We have found it useful to group service quality indicators into seven broad categories.

Reliability indicators measure the continuity of the basic service. Electric utilities are expected to provide a continuous power supply at all times, so interruptions in power supply constitute a diminution in service quality. Reliability is often measured by the frequency and duration of power interruptions.

Non-emergency on-site services pertain to non-safety related services that require visits to customer premises, such as a visit to repair a broken meter. On-site visits to restore power supplies may fall into this category if the supply problems are customer-specific rather than network-related. An example of a non-emergency on-site indicator is the percentage of non-emergency calls that the company responds to within twenty-four hours.

Safety indicators reflect possible health and safety problems if utility products are not delivered properly. Safety indicators are much more common for gas than electric utilities. An example is the time it takes to respond to calls about gas odors.

Telephone services pertain to the quality of service provided by the company's phone center. Since most customers communicate complaints or concerns by telephone, the quality of phone contacts is an important component of overall service and is often linked to other indicators (*e.g.*, the response time for emergency visits depends in part on how rapidly calls are answered and relayed to field personnel). One example of a telephone service indicator is the average time it takes to answer customer calls.

Metering and Billing indicators reflect the quality of these services that the company provides. Quality in this area will be enhanced by timely and accurate meter-reading and bill preparation. Examples of quality indicators include the percentage of prepared bills that must be adjusted because of errors.

Customer satisfaction is a category that reflects how content customers are with their utilities. Indicators include surveys of overall customer satisfaction.

Finally, the *other* category includes a panoply of miscellaneous indicators that have been featured in approved service quality incentive plans. Examples include employee safety and customer outreach and education programs.

37. For example, an updated service quality incentive for Brooklyn Union Gas used just eight indicators, while the plan it replaced contained twenty-one.

Many of these indicators relate to services that non-regulated energy retailers can provide in a competitive market. Therefore, service quality incentives may be less appropriate for these indicators once the competitive marketplace has matured. In the interim, however, the quality of the services that the utility provides is likely to remain an important regulatory concern.

Quality benchmarks are the standards against which measured quality is judged. Benchmarks should be ideally sensitive to a utility's external business conditions and relatively immune to the influence of random events. The quality of energy distribution service, for example, is potentially influenced by a number of external factors, which may be called quality "drivers." The list of relevant factors includes: weather (*e.g.* winds, lightning, extreme heat and cold); vegetation (contact with power lines); the amount of undergrounding mandated by local authorities; the degree of ruralization in the territory (typically increasing the exposure of feeders to the elements and lengthening response times when faults occur); the difficulty of the terrain served; the mix of residential, commercial, and industrial customers; the incidence of poverty; the heterogeneity of languages spoken; the rate of growth in the number of customers; the tendency of customers to relocate; and regulatory changes such as a restructuring of the industry to promote competition. Quality drivers influence customer satisfaction as well as the more operation-specific quality indicators.

Universally accepted quality standards do not exist for utility industries, so commissions have considerable latitude in setting benchmarks. For any given indicator, one straightforward benchmark is the utility's average performance over a recent period. Quality assessments would then depend on measured quality levels that differ either positively or negatively from recent historical experience.

Using past utility performance to set benchmarks is appealing in many ways. This approach ensures that benchmarks will reflect the *typical* external factors faced by a company which, as noted, may vary substantially between utilities. In addition, the resources needed to deliver recent quality levels are presumably reflected in current rates.

However, regulators may not consider a utility's past performance to be an adequate quality standard, especially if recent service levels are poor. Some utility managers may also view the company's history as inappropriate when its performance is exceptionally good. In this case, it may be considered unfairly demanding to expect the utility to match its historically superior performance on an ongoing basis.

An alternative is to base benchmarks on the service quality performance of the industry, defined either nationally or regionally. Industry benchmarks may also be based on measured performance levels for a peer group of comparable utilities. In principle, industry-based benchmarks may be attractive in PBR. They are clearly external to the subject utility, which creates strong performance incentives. Industry benchmarks also tend to be consistent with the operation of competitive market, where customer choices are driven by the cost and quality of products relative to available substitutes.

In practice, however, industry-based benchmarks are often problematic because uniform and publicly-available data are not collected for large numbers of energy utilities. This lack of available data probably explains why so few approved plans contain industry-based quality benchmarks. While this is a recognized problem, some commissions (*e.g.* Massachusetts) are nevertheless examining the desirability of using peer data within their state to set reliability benchmarks for individual utilities.[38]

As noted, a company's measured service quality performance can be affected by external business conditions that are beyond management control. Some of these business conditions are volatile and prone to fluctuations that are hard to predict. Utilities should not ideally be subject to penalties or rewards because random factors have affected their measured service quality. PBR plans can be designed to mitigate the impact of random factors in leading to inappropriate penalties or rewards.

One way to handle the impact of external business conditions is through deadbands. A deadband is a range around a quality benchmark where measured performance is neither penalized nor rewarded. Statistical methods can provide a rigorous foundation for setting deadbands that reduce the probability of inappropriate penalties or rewards to specified levels (*e.g.* 5%). Such statistical methods have been used in several service quality PBR plans for telecom utilities and have been proposed by energy utilities in some states.[39]

The symmetry of the award mechanism is another important design issue. It has been argued that symmetric awards (*i.e.* both rewards and penalties are possible) are not needed when quality incentives are designed only to maintain quality levels which might otherwise decline due to the stronger incentives to cut costs under PBR. However, a strong case can be made that symmetric incentive plans are more appropriate. Symmetric plans can in

---

38. Order on Motion for Clarification by Joint Utilities, Mass. D.T.E. 99-84 (2001) [hereinafter Order on Motion].

39. *See generally* Pacific Economics Group, *Statistical Benchmarking of Utility Service Quality*, (November 9, 2000), *available at* http://www.state.ma.us/dpu/electric/99-84/uc_appb.pdf (offered in testimony by Massachusetts Energy distributors in D.T.E. 99-84).

fact be calibrated to incite only the maintenance of current quality standards. The encouragement of better quality may, in any event, be desirable. All types of PBR, including service quality incentives, are fundamentally motivated by a desire to improve utility performance and not simply prevent performance from slipping. Asymmetric plans generally do not create incentives for companies to improve quality and thus may limit the total customer benefit that is available from utility operations.

Symmetric plans are also more consistent with the behavior of unregulated markets and the competitive market paradigm for regulatory design. Customers in competitive markets routinely pay higher prices for higher quality products, and a symmetric service quality incentive reflects this phenomena. However, competitive markets usually offer an array of goods with varying quality levels, and not all customers choose to consume high-quality goods. In some cases, incentive plans lead to price increases on monopoly services.[40] Where this is the case, at least some customers may be paying for quality improvements that they do not want.[41]

Symmetric service quality plans have been approved for energy utilities. For example, both the California and New York commissions adopted symmetric service quality plans based on explicit findings that the underlying principles are sound. However, asymmetric service incentives are somewhat more common.

The impact of external business conditions on measured service quality performance also tends to support symmetric service quality incentives. As noted, some business conditions can be quite volatile and may lead to inappropriate penalties or rewards. Symmetric service quality incentives reduce the likelihood that random factors will lead to inappropriate net penalties or rewards over the course of a multi-year incentive plan. That is because random changes in business conditions can lead to rewards as well as penalties. Over time, the magnitudes of any inappropriate penalties and rewards can therefore be expected to cancel each other out. All else equal, this leads to reasonable penalties and rewards that on average reflect a utility's underlying quality per-

40. Note that, depending on the other features of the PBR plan, symmetric service quality incentive plans may not lead to price increases even if the utility is rewarded under the plan. For example, if the PBR plan also features as ESM, the service quality reward can be an increase in the allowed return at which earnings are shared, rather than a price increase.

41. This distributional implication is tempered somewhat by some research showing that the *optimal* level of quality in a monopoly market can be provided only if prices are sensitive to the quality of services. Lawrence White, *Quality Variations When Prices Are Regulated*, 3 BELL J. OF ECON. & MGMT. SCI., 425-36 (1972); Carl Shapiro, *Premiums for High Quality Products as Returns to Reputations*, 98 Q. J. of ECON. 659-79 (1983).

formance. This would not be the case with an asymmetric service quality incentive, where external factors may subject a company to penalties without the chance of being compensated with offsetting rewards.

Another significant plan design issue is the magnitude of rewards or penalties levied. In practice, empirical evidence is rarely presented to justify the amount of potential penalties or rewards in a plan. Instead, penalty levels are sometimes chosen with the idea that they are "significant" enough to prevent service levels from declining. The rationale seems to be that the penalties should at least exceed cost savings that the utility might expect by cutting resources used to deliver service quality.

The uncertainties related to the magnitude of rewards or penalties lends additional support for symmetric service incentives over asymmetric incentives. Since regulators often use considerable discretion in setting penalty rates, a symmetric plan may discipline regulators into choosing more appropriate rates. That is, with an asymmetric plan, regulators may err on the side of choosing very high penalties to assure that quality does not decline under the plan. This is less likely under a symmetric plan, which would require an equally high *reward* due to performance improvements. Hence, even if an asymmetric plan is ultimately approved, a symmetric service quality proposal may be beneficial if the prospect of symmetry leads to more appropriate magnitudes for penalty payments.

Ideally, a service quality incentive requires information on how customers value different quality indicators so that the potential rewards and penalties for performance will reflect the value of the service provided. Given its importance, it is somewhat surprising that little empirical work has been done on customer valuations of quality indicators included in incentive plans. In part, this is because quality is inherently difficult to value. But while this information may not be readily available, it can be gathered from a number of sources.

Although a complete discussion of the topic is beyond the scope of this article, three basic methods are used to estimate the value of service quality. One method uses proxy data related to the service attribute. For example, the value of having to wait for a field service representative to arrive can be approximated as the customer's lost wages (*i.e.*, the opportunity cost of the customer's time). Proxy prices have the advantage of simplicity, but they can be imprecise and bear a tenuous link to actual service valuations.

A second method of estimating customer valuation uses market-based measures for the value of service. The difference between firm and interruptible rates is one example of market-based data that reflects some customers' valuations of reliability. Another example of market-based measures is the use of hedonic price indexes, which are developed by regressing market prices on identifiable quality attributes. Hedonic price indexes reflect the notion that price differences are due to implicit markets for individual product characteristics. Some official statistics utilize hedonic methods; for example, the Bureau of Labor Statistics adjusts for quality changes of some products when computing the Consumer Price Index.[42] While market-based methods are often conceptually sound, they can be controversial, are often not well-understood, and can produce divergent estimates of underlying quality valuations. In addition, hedonic methods are less likely to capture the underlying quality valuations in utility markets since prices often reflect regulatory decisions rather than market forces.

Finally, quality valuations can also be obtained through customer surveys. An advantage of this approach is that surveys can focus on specific aspects of utility services that might be included in an incentive plan. However, survey results reflect subjective perceptions rather than actual consumer behavior, and hypothetical valuations may not be a good guide to how consumers would actually act in markets.

2. Precedents

There are a large number of approved PBR plans for service quality. Service quality PBR is especially well established in New York and California. Generic proceedings on service quality PBR have been held in several states.[43]

3. Evaluation

Service quality PBR is becoming more important in utility regulation. Quality incentive mechanisms can play an important role in ensuring that incentives for quality and unit cost containment are balanced. Despite their importance, research to place these plan provisions on a solid foundation of reason and empirical research is not well advanced.

D. Other Non-Comprehensive Benchmarking

1. Basics

Non-comprehensive benchmark plans are similar in many respects to comprehensive benchmark plans. They involve performance indicators, performance benchmarks, and award mechanisms. The main difference is that a non-comprehensive plan does not cover all dimensions of company performance.

42. The CPI calculations consider improvements in personal computers, for example.

43. *See generally* Order on Motion, *supra* note 38.

2. Precedents

Traditionally, many approved benchmark plans for energy utilities have been markedly non-comprehensive insofar as they feature a small number of narrowly focused performance variables. For electric utilities, indicators measuring performance in the areas of fuel procurement, generator management, and demand-side management (DSM) have also historically been common. In a 1986 survey on incentive regulation, Joskow and Schmalensee identified forty-three generator performance plans in nineteen states.[44]

In the gas distribution industry, there are numerous approved benchmarking plans for gas procurement cost. The design of gas supply benchmarking has been challenging. Frontier issues include the treatment of transportation cost and the provision of incentives for gas cost stability.

3. Evaluation

The merits of non-comprehensive benchmark plans are broadly similar to those of non-comprehensive indexing mechanisms. Performance areas can be targeted that are of special concern to the regulatory community. The chief difference between non-comprehensive benchmarking and non-comprehensive indexing results from the sharing that necessarily applies to the latter approach. Sharing reduces regulatory and business risks. The net effect of sharing on incentives depends on whether the presence of a sharing mechanism permits an extension of the period between general rate cases.

VII. BENEFIT SHARING PROVISIONS

As we explained in section II, a well-designed PBR plan generates stronger performance incentives with fewer operating restrictions than cost of service regulation. Performance is then expected to improve under such a plan, and utilities can earn more and their customers pay less, at the same time, than could be the case under cost of service regulation. The details of a PBR plan will influence the allocation of plan benefits between utilities and their customers, and the proper mechanism for sharing plan benefits is a controversial issue in many PBR proceedings.

Appropriate benefit-sharing provisions allow *both* shareholders and customers to fare better than under standard rate regulation. If PBR is voluntary, utilities have little incentive to agree to a plan unless it offers a reasonable chance for higher earnings, especially in view of the higher risk entailed. It is incorrect, then, to

44. Paul R. Joskow & Richard Schmalensee, *Incentive Regulation for Electric Utilities*, 4 YALE J. ON REG. 1 (1986).

point to higher utility earnings as evidence of the "failure" of PBR. Higher utility earnings are consistent with successful PBR as long as customers also benefit compared to a continuation of the status quo.

The selection of a benefit sharing mechanism should be based on sensible criteria. We evaluate alternative sharing mechanisms primarily in terms of their effect in three areas: performance incentives, cross-subsidization, and risk reduction. Other attributes considered include simplicity and "salability," *i.e.*, the ability to convincingly demonstrate benefit sharing. In this section, we evaluate three benefit-sharing provisions that may be used under various approaches to PBR: 1) stretch factors; 2) adjustments to initial rates; and 3) earnings-sharing mechanisms.[45] We describe the basic features of each approach, detail important precedents, and evaluate its advantages and disadvantages as a means of benefit-sharing.

A. The Stretch Factor

As we have already seen, the X-factor in a rate or revenue-cap index influences the allowed escalation of rates or revenues. A higher value for X therefore benefits customers of regulated services. An X-factor designed in accordance with classic American principles is calibrated to reflect the TFP trend of the relevant industry. One way to share expected plan benefits with customers, then, is to set the X-factor at a level above the calibration point. This component of the X-factor is often called a stretch factor. It is set in advance to help ensure an external character for X. However, it can be allowed to vary from year to year.

An early use of stretch factors was in the initial price cap plan approved by the FCC for AT&T. A "consumer dividend" of 0.5% was added to the calculated TFP differential of 2.5% to yield an X-factor of 3%. Since then, stretch factors have been featured in many U.S. indexing plans. They are sometimes explicit and sometimes implicit in the choice of an X-factor.

An important advantage of stretch factors is that their values can be assigned independently of a company's unit cost growth during the plan, so they do not compromise performance incentives or raise cross-subsidy issues. Valuations made prior to the first indexing period clearly have this attribute.

Some critics of stretch factors have argued that regulators cannot commit to a stretch factor policy for subsequent plans. Absent such commitments, parties might reasonably expect stretch factors in future plans to reflect the utility's unit cost in the current plan. However, the brief history of U.S. price cap

45. A less general form of sharing which is not discussed at length is the kind encountered in benchmarking mechanisms. This was discussed *supra* Part VI.

regulation does not provide much evidence to support the validity of this concern.

To the extent that they are external, stretch factors are not useful in reducing business risk. For example, the application of a stretch factor may give customers a 0.5% break in rates even if the company's earnings were depressed by mild weather and a regional recession. As for regulatory risk, the short history of U.S. price cap regulation provides few clear lessons. Critics of stretch factors argue that they lack the solid foundation in economic research that unit cost calibration points have. Regulators' abilities to assign values for stretch factors arbitrarily exacerbates the risk. On the other hand, the range of explicit stretch factor values that have been approved is actually fairly narrow. Nearly all have fallen in the 0% to 1.0% range.

Regarding their salability, stretch factors are appealing to regulators insofar as they represent an advance commitment to customer benefits. Customers therefore benefit whether or not performance improvements are realized. On the other hand, customers and their representatives may not understand that stretch factors are designed to be insensitive to a utility's current earnings and so may resent high earnings if they occur.

B. Adjustment of Initial Rates

Another important approach to sharing plan benefits is to lower the initial (base year) rates or revenue requirement below the levels that would otherwise result. When this is done, consumers immediately reap a plan benefit. Moreover, benefits continue to be created in subsequent years since, with lower initial rates, lower prices result from index-based rate adjustments. This approach has been more widely used in Great Britain than in North American PBR to date.

The advantages and disadvantages of initial rate cuts as a benefit sharing mechanism are similar to those for stretch factors. To the extent rate cuts do not deepen in response to performance improvements, performance incentives are strong. Cuts at the outset of the first plan are not problematic. The concern is, instead, with the size of initial rate cuts that might occur at the start of subsequent plans and their linkage to past performance improvements under PBR. As with stretch factors, initial rate cuts do not mitigate business risk and can actually increase regulatory risk absent a proper conceptual and empirical foundation. Customers benefit whether or not utility performance improves, but may resent high earnings if they occur.

A unique advantage of initial rate adjustments is the immediacy of the benefits. On the other hand, a unique disadvantage is the difficulty of demonstrating that rate cuts are in fact being made when, as is common for energy utilities, companies propose rate increases just prior to indexing. Utilities are then in the awkward position of claiming they could have asked for even larger price increases and that customers have benefited from the company's restraint. Since other parties will have differing opinions about whether any increase is warranted, the benefits may be less convincing.

C. Earnings-Sharing Mechanisms

An earnings-sharing mechanism (ESM) adjusts a company's price restrictions when its earnings rate has been in a certain range over a recent historical period. The mechanisms are established in advance of their use and typically function for several years. The most widely-used earnings rate measure is return on equity (ROE).

Approved ESMs vary significantly in several ways. The most important difference is the shares of surplus (and/or deficit) earnings assigned to shareholders and customers. These shares may change in different ranges of the ROE. Many plans feature a range (called a deadband) in which rates are not sensitive to ROE fluctuations. Immediately beyond the deadband, the customer share is commonly 50%. In some plans, it increases substantially when ROE is extraordinarily high and falls substantially when it is extraordinarily low. Such plans are said to be characterized by "regressive" sharing mechanisms. Alternatively, a "progressive" ESM reduces the customer's share of benefits as ROE increases. Some plans are symmetric in the sense that they provide for rate decreases when earnings are high and rate increases when earnings are low. Other plans provide for rate adjustments only when earnings are high.

ESMs are one of the oldest approaches to PBR. They were used in England as early as 1855 to regulate local gas companies.[46] A plan was adopted in Canada in 1877 to regulate Consumers Gas. An early American plan was established in 1905 for Boston Consolidated Gas. A plan for Potomac Electric Power, approved in 1925, remained in effect until 1955. More recent PBR plans for many U.S. and Canadian energy utilities involve ESMs. However, ESMs were not included in the rate-cap plans for National Grid (Mass.) or the plans approved by the FERC for oil pipelines or the power transmission services of International Transmission.

Experience with ESMs in the U.S. telecommunications industry is also interesting. For example, ESMs were featured in an

46. For further discussion of the early precedents *see generally* Harry Trebing, *Toward An Incentive System of Regulation*, PUB. UTIL. FORTNIGHTLY, July 18, 1963, at 22.

early PBR plan that the FCC approved for LECs in 1991.[47] At around the same time, commissions in several states approved price cap plans with ESMs for LEC services under their jurisdiction. However, ESMs have become rare in the telecom industry in more recent years. Instead of ESMs, most plans use either stretch factors or initial rate cuts to ensure benefit-sharing. The rate-indexing plan for Canadian telecom utilities does not have an ESM.

Regulators in Britain have considered the adoption of ESMs on several occasions. One review of a British Gas plan featured an especially thorough deliberation of this issue. However, few ESMs have been adopted to date in Britain. A recent and notable exception is the latest plan for the transmission system operation (SO) services of National Grid. There are also no ESMs in the approved index plans for Australia's power transmission and distribution utilities.

ESMs have some important advantages as benefit sharing mechanisms. One is their ability to mitigate risk. ESMs are an automatic means of adjusting rates for a wide range of risky external developments. As an alternative to initial rate reductions and X-factors, they also reduce regulatory risk. In effect, benefits are shared as they are realized and there is less pressure on regulators to choose stretch factors and initial rate reductions that share the (usually speculative) plan benefits. There is, however, some regulatory risk to the utility in proposing an ESM: principally, the risk that the Commission will approve an asymmetric ESM in which earnings shortfalls are not shared.

In addition to risk management, another benefit of ESMs is their salability. Customers and their representatives can appreciate how an ESM aligns shareholder and customer interests. Benefits seem transparent and easily computed. If the distributor had a 14% ROE last year, for instance, the ESM might reduce the revenue from regulated services by the value of a percentage point of ROE. ESMs will also keep utility earnings within politically acceptable bounds.

On the downside, ESMs do not, by themselves, guarantee that customers benefit from a PBR plan. Customers may complain if distributor earnings exceed the target ROE but fail to reach the

47. The decision to allow ESMs in this plan was due in part to the unique circumstances of the case. The plan applied to eight different companies with service territories as diverse as New England and the Pacific Northwest. Although the FCC recognized that regional differences in economic growth and other conditions could cause variations in the productivity growth potential of LECs, it also found that the service territories of several LECs accounted for most of the business in their regions. Because the regional data would be inappropriate for these essentially one-firm service areas, the PCIs were designed using national unit cost data. The ESMs were viewed in large part as a "backstop" to reduce the resulting risk.

sharing range. Higher rates due to an earnings shortfall can be especially controversial.

Another disadvantage of ESMs is that the continued focus on earnings keeps alive inherently controversial issues like utility-affiliate transactions and cost allocations between a utility's various regulated services and any competitive market services. Unwarranted or excessive regulator attention to these issues can both discourage efficient diversification and impose undue regulatory costs. Utilities will become more sensitive to the problems associated with ESMs as they seek to realize potential scale and scope economies from simultaneous involvement in regulated and competitive markets.

The effect of ESMs on performance incentives is controversial. Compared to a multi-year rate-cap plan in which rate restrictions are completely insensitive to a utility's performance, a plan with an ESM weakens a company's performance incentives. After all, utility managers have less incentive to improve performance if half of the after-tax benefits go to customers. On the other hand, the various advantages of ESMs may permit the interested parties to agree to an extension of the period between plan reviews. ESMs may also help the parties agree to plan termination provisions that have less deleterious incentive consequences. For example, it can be agreed that in the event of any cost based true-up of rates at the end of the plan, a company is entitled to keep its share of any surplus earnings and is not entitled to compensation for its share of surplus losses.

The analysis of the impact of ESMs on the direct cost of regulation has a similar flavor. ESMs increase regulatory costs during periods where companies are not otherwise subject to regulatory intervention, such as a multi-year rate plan. For example, with ESMs it may be necessary to compute the cost of regulated services, and therefore to allocate total cost between regulated and unregulated services.[48] This effect is offset to the extent that an ESM can extend the period between other, more extensive regulatory interventions.

The reasons for the prevalence of ESMs in the approved PBR plans of U.S. energy utilities and their relative paucity in the PBR plans of telecom utilities merit brief consideration. Two explanations seem plausible. First, cost allocation issues have historically loomed larger for telecom companies than for energy utilities. Interstate access and local exchange services to business customers of LECs have long been subject to physical bypass, while residential customers have cellular bypass options and, increasingly, access to alternative land line providers. Because customers have

48. This is a major concern for telecom utilities, which typically provide extensive regulated and unregulated services from the same facilities.

so many alternatives to utility network service, the marketing and cost allocation issues that result from ESMs may be more costly for telecom utilities. A second reason for the discrepancy in the use of ESMs may be the relative novelty of PBR for energy utilities. As noted above, many early PBR plans for telecoms featured ESMs, but earnings-sharing in the industry has become rarer over time. Similarly, ESMs may become less common for energy utilities as regulators and parties gain experience with PBR.

VIII. PLAN TERMINATION PROVISIONS

Plan termination provisions are another important class of PBR tools that are applicable to a range of basic PBR approaches. One important provision is the term of the plan. Provisions for resetting rates at the conclusion of the plan are also important.

A. Plan Term

Regarding plan term, the trend in PBR has clearly been towards longer term plans. Three year plans of durations were typical during the 1990's. More recently, five-year terms have become standard and some plans of considerably longer duration have been approved. Especially noteworthy in this regard are the ten-year plans for power distribution services of National Grid in Massachusetts and New York.

Plans of longer duration strengthen performance incentives and alleviate concerns about cross-subsidies and novel operating practices that can lead to operating restrictions. Longer terms are especially useful in encouraging initiatives that involve up-front costs to achieve long-run efficiency gains. That is one reason why longer plan terms are of interest in PBR plans occasioned by utility mergers. Both of the National Grid plans just mentioned involved mergers.

On the downside, longer plan terms can increase both business and regulatory risk. This makes them less suitable for businesses undergoing rapid change or for regulatory jurisdictions where there is exceptional risk of unusual stretch factors or initial rate adjustments. The risk of a longer plan term can be reduced by several other plan provisions, including industry-specific inflation measures, Z-factors, marketing flexibility, and ESMs. In choosing among these tools, plan designers should, as usual, be mindful of their differential effects on plan externality.

B. Rate Reset Provision

The rate reset provisions of PBR plans vary widely. At one extreme, the plan may include a provision for a full-scale cost-based rate or revenue requirement true-up at the plan's conclusion. At the other, a plan could be reset entirely on the basis of external data. For example, a rate or revenue cap index could be revised only to better reflect the recent unit cost trend of the relevant industry.

The rate reset provisions of most PBR plans for energy utilities lie between these extremes. The most common approach is to simply not specify how rates might be reset. An interesting alternative is to establish by some means that in the event of a cost-based rate true-up, utilities will be entitled to keep some of the demonstrable benefits of superior performance.[49] Plans with this innovative feature have included those for the power distribution services of National Grid (Mass.) and of power distributors in Victoria, Australia.

Rate reset provisions are important because of their effect on the externalization of the regulatory mechanism. To the extent that a full cost-based rate true-up is not ensured, performance incentives are strengthened and there are reduced concerns about cross subsidies and novel practices that can lead to operating restrictions. Incentives for initiatives involving up-front costs and long term benefits are, once again, especially affected. On the downside, rate plans that do not call for a full cost-based rate reset involve greater risk. As in the case of longer plan terms, a variety of other mechanisms are available to mitigate the resultant risk.

IX. CONCLUSION

Our survey has revealed that many tools are available for the construction of PBR plans for energy utilities. These tools have differential impacts on risk and return. Careful plan design can help achieve a risk-return balance that is right for utilities and their customers. Tools that reduce risk without unduly raising concerns about performance incentives and operating practices are especially desirable. In our experience, this list includes industry-specific inflation measures, X-factors based on regional productivity trends, Z-factors, and optional rates and services.

Our analysis has also highlighted the importance of encouraging energy utilities to undertake initiatives that involve up-front cost to achieve long term performance gains. Plan termination provisions play an especially critical role in the incentives for such initiatives. The greater risk of provisions that strengthen such incentives can be offset by more careful attention to eliminating unnecessary sources of operating risk under the plan. The time horizons of most PBR plans are still sufficiently short that utilities must plan carefully if they hope to profit from long-term performance initiatives.

49. In principle, they might also be asked to share the losses from demonstrably inferior performance.

X. APPENDIX: A SUMMARY OF NOTEWORTHY PBR PLANS

A. *Indexed Rate Caps*

1. Gas Distributors

Jurisdiction	**Company / Term of Plan**	**Operations Subject to PBR**	**Indexing Formula**	**Benefit Sharing Mechanism**
California	San Diego Gas & Electric	Gas delivery services	IPI - X +/- Z 2000: X = 1.08% 2001: X = 1.23% 2002: X = 1.38%	Allowed ROE can be adjusted through a Cost of Capital "Trigger Mechanism" Shareholders receive all gains and losses up to 25 basis points around authorized ROE Between 25 and 300 basis points the share- holder (ratepayer) share of losses and gains rises(declines) from 25%(75%) to 100%(0%) Shareholders receive all gains 300 points above ROE and are responsible for all losses 300 or more basis points below the authorized ROE
"Opinion Regarding San Diego Gas and Electric Company's Distribution Performance-Based Ratemaking Mechanism." Decision 99-05-030 (May 13, 1999).				
Massachusetts	Boston Gas 1997-2001	Gas delivery services	GDPPI - 0.5% +/- Z factors X= 0.5% = 0.1% productivity offset + -0.1% input price differential + 0.5% consumer dividend Note: Original X factor also included a 1.0% accumulated inefficiencies factor, but this was later eliminated.	0.5% consumer dividend Earnings Sharing Mechanism: 25/75 sharing with ratepayers of ROE above 15% or below 7.0%
"Order on Motion of Boston Gas Company." Massachusetts Department of Public Utilities D.P.U. 96-50-C (Phase I) (May 16, 1997).				

Maine	Bangor Gas Company 2000-2010	Gas Delivery Services	First 5 years: GDPPI Next 5 years: GDPPI - .5%	50/50 sharing of ROE in excess of 15%
"Order Approving Rate Plan." State of Maine P.U.C. Docket No. 97-795 (June 26, 1998); 186 P.U.R.4th 223.				
Ontario	Union Gas 2001-2003	Gas Delivery Services	GDPP-2.5% +/- Z	50/50 sharing of ROE more than 100 basis points above or below target ROE
"Decision with Reasons," Ontario Energy Board RP-1999-0017 (July 21, 2001)				
Britain	British Gas 1987-1992	All services subject to regulation	RPI - 2.0% +/- Z (RPI = Retail (Consumer) Price Index)	None
	British Gas 1992-1994	No change	(RPI - 5.0%) * (share of non-gas costs)+ % change in (F - Y) * (1992 share of gas costs) +/- Z factors F = an external index of gas costs Y = Efficiency factor for gas purchases (ranges from 2.01% to 6.15%)	None
	British Gas 1994-1997	Customers without retail access:All services subject to regulation	Sales services: (RPI - 4.0%) * (share of non-gas costs) + % change in (F - Y) * (1992 share of gas costs) +/- Z factors Transportation and Storage Services: RPI - 5.0% +/- Z factors	None
	British Gas 1997-2002	Customers with retail access: Gas delivery services No change	1997: 21% price cut 1998-2002: RPI - 2.0%	None

2. Electric Utilities

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism

California	PacifiCorp 1994-1996	Bundled Power Service	% change electric utility input price index - 1.4% +/- Z % change input price index = weighted average of DRI forecasts of inflation for capital, fuel, materials and labor; the weights were determined from the share of each component in Pacificorp's 1992 total cost	None
"Opinion." Public Utilities Commission of California Decision 93-12-106 (December 3, 1993).				
California	PacifiCorp 1997-1999	No change	% change electric utility input price index -1.5% +/- Z % change input price index = weighted average of DRI forecasts of inflation for capital, fuel, materials and labor; the weights were determined from the share of each component in Pacificorp's 1992 total cost	None
	San Diego Gas & Electric 1999-2002	Power Delivery	IPI - X +/- Z 2000: X = 1.32 2001: X = 1.47 2002: X = 1.62	Allowed ROE can be adjusted through a Cost of Capital "Trigger Mechanism" Shareholders receive all gains and losses up to 50 basis points around authorized ROE Between 50 and 300 basis points the shareholder (ratepayer) share of losses and gains rises(declines) from 25%(75%) to 100%(0%) Shareholders receive all gains 300 points above ROE and are responsible for all losses 300 or more basis points below the authorized ROE
"Opinion Regarding San Diego Gas and Electric Company's Distribution Performance-Based Ratemaking Mechanism." Decision 99-05-030 (May 13, 1999).				

	Southern California Edison 1997-2001		CPI - X +/- Z 1997: X = 1.2% 1998: X = 1.4% 1999-2001; X = 1.6%	Allowed ROE can be adjusted through a Cost of Capital "Trigger Mechanism" Shareholders receive all gains and losses up to 50 basis points around authorized ROE Between 50 and 300 basis points the shareholder (ratepayer) share of losses and gains rises(declines) from 25%(75%) to 100%(0%) Shareholders receive all gains 300 points above ROE and are responsible for all losses 300 or more basis points below the authorized ROE
	"Decision on Application of Southern California Edison (A.93-12-029)," D96-09-092. Public Utilities Commission of the State of California (September 6, 1996).			
Maine	Bangor Hydro Electric 1998-2000	Power Delivery	GDPPI - 1.2% +/- Z	
	"Corrected Order, Proposed Increase in Rates." State of Maine Public Utilities Commission Docket No. 97-116 (March 24, 1998).			
	Central Maine Power 1995-2000	Bundled Power Service	1995: GDPPI - 0.5% +/- Z 1996: If % change in GDPPI is less or = 4.5% GDPPI - 1.0% +/- Z factors if % change in GDPPI is > 4.5%, the greater of: 3.5% - Penalties +/- Z factors, or (1-QF)*(GDPPI - 1.0%) +/- Z factors 1997-99: (1-QF)*(GDPPI - 1%) +/- Z factors where QF=0.375 to reflect long-term Qualifying Facility contracts that do not vary with the rate of inflation	50/50 sharing of profits outside the benchmark ROE +/-3.5% deadband; 1995 ROE=10.55% is indexed in future years by Moody's dividend and bond yields
	Central Maine Power Company. Maine Public Utilities Commission 159 P.U.R.4th 209 (January 10, 1995); Docket No. 92-345 (II).			

	Central Maine Power 2001-2008	Power Delivery	GDPPI - X +/- Z X increases from 2% to 2.9% during the plan	Earnings sharing only **below** ROE of 5.2%
	"Order Approving Stipulation." Maine Public Utilities Commission Docket No. 99-666 (November 16, 2000).			
Ontario	Ontario electricity distribution companies 2000-2003	Power Distribution	IPI – 1.5% +/- Z	Earnings are shared with customers over a
	"Decision with Reasons." Ontario Energy Board RP-1999-0034 (January 18, 2000)			
England & Wales	Regional electric cos. (RECs) 1990-1995	Power distribution services	RPI - X Each of the companies has a different X value, ranging between 0 and - 2.5%	None
	RECs 1995	No change	RPI - 2.0% Initial Price Cut 11-17%	None
	RECs 1995-2000	No change	RPI - 3.0% Initial Price Cut 9%	None
	RECs 2001-2005	No change	X = 3% Initial price cut 19-33%	None
	National Grid Company (transmission) 1990-1993	Power transmission services	% change in RPI	None

Scotland	Scottish Power 1990-1995	Customers without retail access: all services subject to regulation Customers with retail access: delivery, billing, and collection	Transmission: RPI - 1.0% Distribution: RPI - 0.5% +/- Z Billing and Collection: RPI - 0.5% +/- Z	None
	Scottish Power 1995-2000 (1994-1999 for transmission)	No change	Transmission: RPI - 1.0% Distribution: RPI - 2.0% Billing and Collection: RPI - 2.0%	None
	Scottish Hydro 1990-1995	Customers without retail access: all services subject to regulation Customers with retail access: delivery billing and collection	Transmission: RPI - 0.5% Distribution: RPI - 0.3% +/- Z Billing and Collection: RPI - 0.3% +/- Z	None
	Scottish Hydro 1995-2000 (1994-1999 for transmission)	No change	Transmission: RPI - 1.5% Distribution: RPI - 1.0% Billing and Collection: RPI - 2.0%	None
Northern Ireland	Northern Ireland Electricity 1992-1997	Customers without retail access: all services subject to regulation Customers with retail access: power transmission and distribution services	Transmission and Distribution: - Fixed component: RPI + 3.5% - Variable component: RPI + 1.0% +/- Z Billing and Collection: RPI +/- Z Factors	None
Australia: Victoria	Power Distributors 1995-2000	Power Delivery	CPI - X X ranged from 1% to 1.92% by company	None
	Power Distributors 2001-2006	Power Delivery	CPI - X Initial price cut ranged from 9.1% to 18.4% 2002-2006: X = 1%	None
	"Electricity Distribution Price Determination, 2001-05." Office of Regulator General, Victoria (September 2000).			

3. Gas Pipelines

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism

FERC	Transwestern Pipeline Co. 1998-2005	Gas transmission	0.60 * (% change GDP Implicit Price Deflator) Annual index-based rate increase cannot be less than 2.0% or greater than 5.0%	None
	"Order Approving Transwestern Contested Settlement Agreement. 72 F.E.R.C. ¶ 61, 085 (July 27, 1995); Docket No. RP95-271 et al.			

4. Oil Pipelines

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism
FERC	U.S. oil pipelines (except Trans-Alaska) 1995-2000	All services subject to regulation	% change in Producer Price Index for Finished Goods - 1.0%	None
	U.S. oil pipelines (except Trans-Alaska) 2000-2005	All services subject to regulation	% change in Producer Price Index for Finished Goods - 1.0%	None
	"Revisions to Oil Pipeline Deregulation Pursuant to the Energy Policy Act of 1992." Order No. 561; F.E.R.C. Stats. & Regs. ¶ 30, 985 (1993).			
	"Five Year Review of Oil Pipeline Pricing Index." 18 C.F.R. Part 342; Docket No. RM00-11-000; 93 F.E.R.C. ¶ 61, 266 (December 14, 2000).			

B. Rate Freezes and Pre Scheduled Adjustments

1. Gas Distributors

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism
Michigan	Consumers Gas	Gas supply and delivery	Freeze	50/50 between 13.51-17.5% and 25 utility/75 customers in excess of 17.5%
	"In the matter of the application of Consumers Energy Company for approval of an experimental pilot program for expanded gas customer choice." Michigan Public Service Commission Order in Case No. U-11599 (December 19, 1997).			
	Michigan Consolidated Gas 1999-2001	Gas supply and delivery	Freeze	50/50 between 13.51-17.5% and 25 utility/75 customers in excess of 17.5%

2. Electric Utilities

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Rate Adjustment Provisions	Benefit Sharing Mechanism
Connecticut	United Illuminating 1997-2001	Retail base rate	Freeze	Earnings above 11.5% ROE allocated equally: 1/3 shareholders 1/3 ratepayers 1/3 increased amortization of assets Co. may apply for rate relief if forecasted ROE falls below annual 10% rate
Iowa	MidAmerican Energy Company 2001-2005	Power Delivery	Freeze	50/50 split for ROE between 12% and 14% Over 14% company only receives one-sixth
Massachusetts	National Grid USA 2000-2010	Power Delivery	Price Freeze 2000-2005 2006-2010: Prices adjusted by index of regional power distribution charges	None
	“Rate Plan Settlement.” Massachusetts DTE Docket DTE 99-47 (November 29, 1999).			
Michigan	Edison Sault Electric	Power Delivery	Freeze	None
	“In the Matter of the Application of Edison Sault Electric Company for Authority to Implement Price Cap Regulation.” Michigan Public Service Commission 164 P.U.R. 4^{th} 1 (September 21, 1995).			
	Consumers Energy	Power Delivery	Freeze	50/50 sharing of ROE between 13.51-17.5% 25/75 for ROE above 17.5%
	“Order Approving Application.” Michigan Public Service Commission U-11599 (December 19, 1997).			
Missouri	Union Electric Co. 1995-2001	Retail Power Sales services	Freeze	50/50 sharing of ROE between 12.61% - 14.0% All earnings above 14.0% ROE returned to ratepayers
	"Report and Order." Missouri Public Service Commission; ER-95-411(July 21, 1995)			
New York	National Grid USA 2001-2011	Power Distribution	Freeze	50/50 sharing of ROE above 11.75%, computed cumulatively

	"Order and Opinion Authorizing Merger and Adopting Rate Plan." State of New York Public Service Commission, Opinion No. 01-6 in Case 01-M-0075 (December 3, 2001).			
South Dakota	Black Hills Power & Light	Bundled Power Service	Freeze	None
	Docket EL 95-003 1995.			
Alberta	Northwestern Utilities 1999-2002	Bundled Power Service	Fixed price increases of: 1999: .5% 2000: 1% 2001: 1% 2002: 2%	200 basis points > NEB return then 50% reduction in rate increase 300 b.p. > NEB return then 75% reduction 400 b.p. > NEB return then no increase in rates 300 b.p. < NEB return then 50% increase in rates
	"An Application for Approval of Rates, Tolls, Charges, and Terms and Conditions of Service for Core Customers for 1998 through to 2002." Alberta Energy and Utilities Board Decision U98060 File 1502-1 (March 31, 1998). Docket EL95-003, 1995			

C. Comprehensive Revenue Caps

1. Gas Distributors

Jurisdiction	**Company / Term of Plan**	**Operations Subject to PBR**	**Indexing Formula**	**Benefit Sharing Mechanism**
California	Southern California Gas 1997-2002	Gas delivery	%Gas Utility Price Index - X +/- Z Gas utility price index is a weighted average of inflation in price subindexes for capital, labor, and materials inputs X has the following values: 1997: 2.1% 1998: 2.2% 1999: 2.3% 2000: 2.4% 2001: 2.5% X has three components: 0.5% industry productivity trend 1.0% to reflect declining rate base a consumer dividend that varies annually	A consumer dividend that increases from 0.6% in 1997 to 1.0% in 2001 in 0.1% annual increments Earnings sharing beginning 25 basis points above the benchmark return on equity; there are nine sharing bands, with shareholders' portion of incremental earnings increasing from 25% to 100% as ROE increases
	"In the Matter of the Application of Southern California Gas Company to Adopt Performance-Based Regulation ("PBR") for Base Rates to be Effective January 1, 1997." 179 P.U.R.4th 237 (July 16, 1997).			

2. Electric Utilities

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism
Oregon	PacifiCorp 1998-2000	Distribution Service	GDPPI - X X = 0.3%	
	"In the Matter of the Revised Tariff Schedules in Oregon filed by PacifiCorp." Public Utility Commission of Oregon Order No. 98-191 (May 5, 1998).			
England & Wales	National Grid 1993-1997	Power transmission services	RPI - 3.0%	None
	National Grid 1997-2001	No change	1997: 20% price cut	None
	National Grid 2001-2006	Power transmission service (delivery only)	RPI 1.5%	None
Australia: Victoria	PowerNet Victoria	Power Transmission services	CPI - 1.79%	None
Australia: New South Wales	Transgrid and Energy Australia 1996-1999	Power Transmission services	CPI - 3%	None
	"NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04." Australian Competition and Consumer Commission File No. CG98/118.			
	Transgrid 1999-2004	Power Transmission services	CPI + 1.3%	None
Australia: Queensland	Powerlink 2002-2007	Power Transmission services	CPI + 6.37%	None
	"Queensland Transmission Network Revenue Cap 2002-2006/07: Decision." Australian Competition and Consumer Commission File No. C2000/659 (November 1, 2001).			

3. Oil Pipelines

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism

Canada - National Energy Board	Interprovincial Pipeline 1995-1999	Revenue requirement excluding "non-routine adjustments"	CPI - 0% CPI inflation cannot be less than 1% or greater than 5% in any given year	Cost performance sharing mechanism:60/40 sharing with tollpayers if Net Income is between $51.5 million and $58 million If Income > $58 million, 50/50 sharing
	Interprovincial Pipeline (Enbridge) 2000-2005	Revenue requirement excluding "non-routine adjustments"	.75 * % change in GDP Implicit Price Index +/- Z	50/50 net income sharing above threshold
	"1995 Incentive Toll Settlement." Order TO-1-95 (March 22, 1995). And Order TO-3-2000 (June 15, 2000).			
	TransMountain Pipeline 1996-2000	Revenue requirement excluding "non-routine adjustments"; these adjustments can include costs resulting from policy changes, insuring service quality, or major facilities expansions	CPI - 0% CPI inflation cannot be less than 1% or greater than 5% in any given year	Pre-tax net income exceeding $13 million is shared 50/50
	"Reasons for Decision." National Energy Board RHW-2-96 (March 1996).			

D. Non Comprehensive Revenue Caps

1. Gas Distributors

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism
Canada	BC Gas 1998-2000	Revenue requirement to recover non-gas operation and maintenance costs	CPI - (X - Customer growth) 1998: X = 2.0% 1999: X = 2.0% 2000: X = 3.0%	If actual O&M costs less than target, 50/50 sharing of difference between actual and target O&M costs
	"In the Matter of BC Gas Utility Ltd. Revenue Requirements Application 1998-2002, Reasons for Decisions." British Columbia Utilities Commission No. G-85-97 (July 23, 1997).			

2. Electric Utilities

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism

California	San Diego Gas and Electric 1994-1999	Operation and Maintenance expenses	Electric: Inflation - .58 * (Customer growth - 1.5%) Gas (non-gas costs): Inflation - .75 * (Customer growth - 1.5%) The inflation measure is a weighted average of inflation in labor and non-labor price subindexes, with weights equal to cost shares in the preceding year; the price subindexes are: Labor: a weighted average of SDG&E's labor cost increases for administrative, clerical/technical, and union workers, with weights equal to the share of each class of workers in payrolls for the preceding year; if these data are not available, the labor inflation subindex is the previous year's growth in the CPI Non-Labor: the non-labor price subindexes used in DRI's O&M cost index for electric or gas utilities, depending on whether inflation factor applies to electric or gas O&M expenses	25/75 sharing of returns between 100 and 150 basis points above authorized returns 50/50 sharing of returns exceeding 150 basis points above authorized returns
	"Application of San Diego Gas and Electric Company to Establish an Experimental Performance-Based Ratemaking Mechanism (U 902-M)." Decision No. 94-08-023; Application No. 92-10-017; 55 CPUC 2d 592; 154 P.U.R. 4th 313 (August 3, 1994).			

3. Gas Pipelines

Jurisdiction	Company / Term of Plan	Operations Subject to PBR	Indexing Formula	Benefit Sharing Mechanism

Canada - National Energy Board	TransCanada Pipeline 1996-1999	Adjustment of costs in an "Incentive Cost Envelope", including operation, maintenance and administration costs	Inflation - X 1997: Inflation = 3.25%, X = 0.50% 1998: Inflation = 3.00%, X = 0.75% 1999: Inflation = 2.75%, X =1.00%	Difference between actual and forecast costs in Incentive Envelope shared 50/50
	Trans Quebec & Maritimes Pipeline Inc. 1997-2001	Adjustment of "Incentive Cost Envelope", which includes Operation and Maintenance Costs less Stress Corrosion Cracking Costs, and Insurance Costs	The "Incentive Cost Envelope" has been set at CA$7,440 million for 1997 It will be subject to a yearly increase : 1998: 1.5% 1999: 1.0% 2000: 0.5% 2001: 0.0%	Miscellaneous discretionary revenues that differ from target shared 1/3 by shareholders, 2/3 by customers
	WestCoast Energy 1997 - 2002	O&M costs, NEB cost recovery expenses, and minor capital additions	O&M costs: CPI - "business process improvement" productivity gains; in C$, these gains were: 1997: 2.4 1998 - 2000: 3.2 2001: 3.3 Others: CPI inflation	50/50 sharing of difference between actual and index-based costs None
	"Reasons for Decision," NEB RH-2-97 Part I and Part II (August 1997)			
Alberta Energy and Utility Board	Nova Gas 1996-2000	Gas Transmission	Revenue is escalated by 2% every year	
	"Cost Efficient Incentive Settlements." Alberta EUB Order No. U96119; File 1601-2 (December 12,1996.)			
FERC	El Paso Natural Gas 1998- 2005	O&M expenses	.93 * (% change GDP Implicit Price Deflator) Annaul escalations cannot be less than 1% or greater than 4.5%	None

E. Benchmark Regulation

1. Electric Utilities

Jurisdiction	Company / Term of Plan	Operations Subject to PBR
Mississippi	Mississippi Power PEP-1 1990-1993	Bundled Power Service
	Mississippi Power PEP-2 1993-	Bundled Power Service
	"Performance Evaluation Plan Rate Schedule PEP-1A." Mississippi Public Service Commission 92-UN-0059 (November 3, 1992), and 90 (December 28, 1990).	
New York	Niagara Mohawk Power Co. 1993-1996	Bundled Power Service
	New York State Electric & Gas 1993-1998	Bundled Power Service
North Dakota	Northern States Power 2001-2005	Bundled Power Service
	"Findings of Fact, Conclusions of Law and Order." North Dakota Public Service Commission Case No. PU-400-00-195 (December 29, 2000).	
	Otter Tail Power 2001-2005	Bundled Power Service
	"Findings of Fact Conclusions of Law and Order." North Dakota Public Service Commission Case No. PU-401-00-36 (December 29, 2000).	
Canada - British Columbia	West Kootenay Power 1997-1999	Bundled Power Service
	British Columbia Utilities Commission Order No. G-73-96 (1996).	

2. Gas Procurement

Jurisdiction	Company / Term of Plan
California	Pacific Gas & Electric San Diego Gas & Electric Southern California Gas
	"Order Instituting Rulemaking to Review the Time Schedules for the Rate Case Plan and Fuel Offset Proceedings.; In the Matter of the Application of Southern California Gas Company to Adopt Performance Based Regulation ("PBR") for Base Rates to be Effective January 1, 1997.
Idaho	Avista
Illinois	Nicor Gas
	"Order." Illinois Commerce Commission 99-0127 (November 23, 1999).
Kentucky	Columbia Gas of Kentucky Louisville Gas & Electric Western KY Gas
Minnesota	Minnegasco
Missouri	Laclede Gas Missouri Gas Energy
New York	New York State Electric and Gas
Pennsylvania	Peoples Gas
Oregon	Avista
	"Opinion." Public Utility Commission of Oregon Order No. 99-521 (August 26, 1999).
Tennessee	United Cities Gas
Washington	Avista

IGUA #15

INTERROGATORY

Ref: PEG Report, p. (iv)
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG states that rate design can be addressed periodically in hearings much like it is today.

a) In PEG's experience, is rate design normally addressed during the term of the IR plan, or alternatively, at the end of the IR plan?

b) What are the advantages and disadvantages of allowing for rate design changes during the term of the IR plan?

c) If rate design changes are permitted during the term of the IR plan, will this necessitate an adjustment to the PCIs or Revenue Cap Indexes ("RCI") set out in the PEG Report? Please explain.

RESPONSE

a) Rate redesign is not normally addressed by traditional means (*e.g.* a cost allocation study) during the term of a *price* cap plan. However, some price cap plans give utilities some discretion to adjust rates during the plan without traditional hearings. PEG does not know the precedents with regard to *revenue* cap plans.

b) Rate changes can be advantageous if current rates aren't reflective of cost and demand conditions. On the other hand, the redesign of rates can cause some customers to experience rate increases well above those that they would otherwise receive under the applicable PCI.

c) Yes, PEG's indexes were calculated under the assumption that no rate redesign will occur. Rate redesign might result in higher fixed charges.

Witness: Mark Lowry

Since, additionally, the number of customers served is a rapidly growing billing determinant this can bolster utility earnings.

IGUA #17

INTERROGATORY

Ref: PEG Report, p. (vi)
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

PEG states that the evidence indicates that declining average use is being experienced by many gas utilities in North America. Please provide copies of all of the evidence relied upon in making this statement.

RESPONSE

Attached please find papers on this topic released by the American Gas Association and the Canadian Gas Association. We also attach an article on this topic written by PEG personnel and recent Massachusetts testimony by PEG partner Larry Kaufmann that addresses the issue. Please see IGUA IR#17 Attachments A to F.

Witness: Mark Lowry

IGUA #18

INTERROGATORY

Ref: PEG Report, p. (vii)
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined
3.2 What are the appropriate components of an X factor?

PEG refers to research it has previously conducted for Board Staff to develop an IR Plan for power distributors in which it was concluded that the average explicit stretch factor approved for energy utilities in rate escalation indexes was around 0.50%. Please provide a copy of that research.

RESPONSE

Please see our response to Enbridge Exhibit R-PEG Tab 3 Schedule 44.

Witness: Mark Lowry

IGUA #19

INTERROGATORY

Ref: PEG Report, p. (vii)
Issue Nos.: 3.1 and 3.2
Issue: 3.1 How should the X factor be determined
3.2 What are the appropriate components of an X factor?

PEG refers to incentive power research it undertook for Board Staff that suggests a stretch factor of 0.42% for EGD and Union. Please provide a copy of that incentive power research.

RESPONSE

See the working papers attached to our response to Enbridge Exhibit R-PEG Tab 3 Schedule 45. Please note that access to the code for the incentive power model requires the signing of a confidentiality agreement.

Witness: Mark Lowry

IGUA #24

INTERROGATORY

Ref: PEG Report, page 21
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

PEG states that “other sources of data” were also used in the Ontario indexing research. Please provide copies of all “other sources of data” relied upon by PEG.

RESPONSE

Please see the working papers attached to PEG’s response to Enbridge Exhibit R-PEG Tab 3 Schedule 2.

Witness: Mark Lowry

IGUA #25

INTERROGATORY

Ref: PEG Report, page 23
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG computed the indexes on the cost of funds for EGD and Union using a 65/35 weighting of debt and equity. The debt to equity ratio currently approved for EGD and Union is 64/36. Please re-calculate your PCIs and RCIs using the 64/36 debt to equity ratio.

RESPONSE

Changing the debt / equity mix by 1% results in no change in the cost of funds to the first decimal. The trend in the cost of funds changes by less than 0.005% which we consider negligible. The impact on the remaining results is also negligible.

PEG cannot provide the results of this update within the timelines of the interrogatories' responses. However, results of this recalculation will be available prior to the commencement of ADR.

Witness: Mark Lowry

IGUA #26

INTERROGATORY

Ref: PEG Report, page 26
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

In computing output quantity indexes for EGD and Union, PEG added to the weather normalized volumes certain estimates, provided by Union and EGD, of their DSM savings. Please provide the DSM savings provided to PEG by Union and EGD.

RESPONSE

Please see PEG's response to Enbridge in Exhibit R-PEG Tab 3 Schedule 2. The DSM volumes will be in sections 1.1 and 1.2 in the dbf files entitled "DSMvolumes.dbf".

Witness: Mark Lowry

IGUA #27

INTERROGATORY

Ref: PEG Report, page 32
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

PEG observes that the Partial Factor Productivity Index for EGD fell by more than 11% in 2003 and did not subsequently regain much of that lost ground. The year 2003 was the first following the conclusion of EGD's targeted IR Plan for O&M inputs. PEG further observed that there is no evidence that this plan produced lasting benefits for EGD customers.

a) What steps can be taken to assure that EGD and Union achieve sustainable productivity gains?

RESPONSE

One important step is to choose a plan period long enough to permit the company to benefit from performance improvement initiatives with long term benefits and longer payback periods. A plan with at least four “out” years is necessary in this regard. Another important step is make sure that rate update s at the conclusion of the IR plan is not based *solely* on the results of a traditional rate case. One way to accomplish this is to undertake statistical benchmarking of the companies' recent historical costs and proposed costs. Another way is to build innovative rebasing mechanisms into the IR plans. A simple example would be to have the new rates based 80% on the results of a new and thorough rate case and 20% on a one-year continuation of the expiring rate adjustment mechanisms. Innovative rebasing rules, which are sometimes called efficiency carryover mechanisms, are increasingly popular features of IR and were discussed on pp. 4-17 of PEG's presentation at the stakeholder meeting on November 3, 2006, which is posted at the OEB website.

Witness: Mark Lowry

IGUA #28

INTERROGATORY

Ref: PEG Report, page 47
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

The evidence indicates that the weather-normalized trends computed by PEG were similar to the companies in the case of Union but not in the case of EGD. Moreover, the figures calculated by PEG suggest average use declines for EGD that are conservatively less severe than those calculated by EGD.

a) Please set out the methodology used by PEG to compute the weather normalized trends for both Union and EGD.

b) If the Board approved weather normalization methods for each company are changed, will this affect PEG's calculation of the Average Use Factor, or any other component of the PCIs or RCIs?

c) If the Board approves the weather normalization methodology requested by Union at Ex.B, Tab 2, how will this affect PEG's calculation of the Average Use Factor, or any other component of the PCI or RCI?

RESPONSE

a) Please see the extensive discussion of this work on pp. 71-74 of our June report. Additional details can be found in the working papers attached to our response to Enbridge Exhibit R-PEG Tab 3 Schedule 2.

b) No it would not, since we did not rely on the weather normalized data provided by Enbridge and Union in our research.

c) There will be no effect, for the reason stated in b).

Witness: Mark Lowry

IGUA #29

INTERROGATORY

Ref: PEG Report, page 61, Union Evidence, Ex.B, Tab 1, page 32 of 48
Issue No.: 3.1
Issue: How should the X factor be determined?

PEG states that a stretch factor used in the determination of an X factor will facilitate the sharing between utilities and customers of any benefits that are expected to result from the stronger performance incentives generated by the Plan. At Exhibit "B", Tab 1, p. 32 of 48, Union claims there is no justification for a stretch factor during the next IR Plan and that the stretch factor proposed by PEG is purely an "ad hoc add on".

a) Does PEG agree that the proposed stretch factor of 0.5% is "purely an ad hoc add on"? If not, why not?

b) In the absence of a stretch factor, how are benefits shared with customers?

c) If there is no stretch factor, should there then be an ESM?

d) Under what circumstance, if any, is it appropriate for an IR Plan to have no stretch factor and no ESM?

RESPONSE

a) The proposed stretch factor is not ad hoc because it is supported by a very sophisticated incentive power analysis. The incentive power model performs simulation exercises based on very realistic assumptions concerning model parameters. The regulatory systems that the model can consider are quite sophisticated. Since Union and Enbridge provide no sensible argument in opposition to stretch factors, the results of this model and the industry precedents should be determinative in this proceeding.

b) Benefits can then potentially be shared in the next rate case or, hypothetically, through a reduction of initial rates.

c) If there is no stretch factor or reduction in initial rates, an ESM may be necessary to fairly share plan benefits.

Witness: Mark Lowry

d) As our previous remarks imply, this might be appropriate in the presence of an initial rate cut, ideally bolstered by a well designed efficiency carryover mechanism. Please note also that a negtotiated rate freeze or any form of implicitly stretch productivity offset would also suffice.

IGUA #30

INTERROGATORY

Ref: PEG Report, pp. (v) and 61, Union Evidence, Ex.B, Tab 1, pp. 32 to 34 of 48
Issue No.: 3.1
Issue: How should the X factor be determined

Union's evidence sets out a number of factors in an attempt to justify the absence of a stretch factor. At page (v) of the PEG Report, PEG states that utilities should demonstrate superior performance with convincing benchmark evidence if they wish to receive special rate treatment with respect to inclusion [or exclusion] of a stretch factor. In PEG's opinion, do the factors identified in Union's evidence demonstrate superior performance such that they ought to receive special rate treatment and have no stretch factor applied to the calculation of their X factor? If not, why not?

RESPONSE

No. The highlight of Union's five sentence argument concerning its operating performance is that they don't operate under annual rate cases. But annual rate cases aren't the norm in the gas utility industry. Union states that it has had three rate cases in ten years. That is in our view pretty close to standard practice in the North American gas utility industry.

Please note also that the PBR plan that Union refers to featured a comparatively short plan term and an earnings sharing mechanism. As can be seen in the table attached to our response to Enbridge Exhibit R-PEG Tab 3 Schedule 45, our incentive power model indicates that a plan of this character doesn't generate strong performance incentives. Union has had an opportunity in this proceeding and in recent rate cases to file convincing evidence of superior operating performance but elected not to do so.

Witness: Mark Lowry

IGUA #31

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 10 of 48
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

Union has requested that certain adjustments be made to the 2000 Base Rates, including:

(a) Items from previous Board Decisions:

(i) Splitting the M2 rate class into two rate classes (M1 and M2);

(ii) Adjustments for the 2008 GDAR capital costs;

(iii) Treatment of S&T deferral accounts;

(iv) DSM;

(b) A one-time adjustment to reflect the 20-year trend weather normalization method.

If these adjustments are approved by the Board, would they necessitate any adjustments to the PCIs and RCIs contained in the PEG Report? If the answer is yes, then provide details of the necessary adjustments

RESPONSE

Splitting the M2 rate class into two rate classes (M1 and M2) might occasion the reassignment of the non-residential class to the other services class in our calculations. This would likely require a recalculation of the ADJs.

Witness: Mark Lowry

IGUA #33

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 18 of 48
Issue No.: 1.1
Issue: What are the implications associated with a revenue cap, a price cap and other alternative multi-year incentive ratemaking frameworks?

Union states that a Price Cap Mechanism should be used because it better addresses the two items that matter most to customers: the price and quality of the service they receive. Does PEG agree that a Price Cap Mechanism addresses these two items better than a Revenue Cap Mechanism? Please explain.

RESPONSE

Yes. A price cap mechanism generates stronger incentives for utilities to develop a market responsive array of rates and services because they benefit financially from increased system use. This benefit is especially great for a company like Union that has an unusually sizable business with large volume customers who have special service packages and comparatively price-elastic demands. The incentive to provide good quality service is also strengthened to the extent that customers respond to poor quality by reducing system use.

Witness: Mark Lowry

IGUA #34

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 36 or 48
Issue No.: 4.1
Issue: Is it appropriate to include the impact of changes in average use in the annual adjustment?

Union states that it does not understand how PEG can calculate separate Service Group PCIs for each Rate Class that contains residential customers without doing a productivity study by Rate Class. Does PEG agree that a productivity study by Rate Class is necessary to determine Service Group PCI's? If not, why not?

RESPONSE

Please see our response to IGUA Exhibit R-PEG Tab 5 Schedule 11.

Witness: Mark Lowry

IGUA #35

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 36 of 4
Issue No.: **4.1**
Issue: **Is it appropriate to include the impact of changes in average use in the annual adjustment?**

Union recommends an alternative to PEG's calculation of Service Group PCI's which is calculated by adjusting the company-wide Average Use Factor by the combined revenue share of the General Service Rate classes. Does PEG agree with Union's proposed approach to calculating the Average Use Factor applicable to the General Service Rate classes? If not, why not?

RESPONSE

Union's proposed approach has the advantage of simplicity and produces similar results for residential customers. However, it provides for substantially more rapid PCI growth for non-residential customers. The Board needs to query whether this is just and reasonable. The Union approach, in essence, assigns a productivity target to the PCI for non-residential services that is designed to apply to all services. Recalling the sources of TFP growth (*e.g.* technological change, scale economies, and changes in external business conditions), this assumes, for example, that residential and non-residential customers make equal contributions to the realization of incremental scale economies. That is certainly debatable inasmuch as output growth for non-residential customers is chiefly a matter of volume growth and our econometric research has established the existence of substantial economies in volume growth. The Board needs to decide whether the benefits of simplicity and slower rate growth for residential customers offset the cost of this inaccuracy.

Witness: Mark Lowry

IGUA #36

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, page 40 of 48
Issue No.: 6.1
Issue: What are the criteria for establishing Z factors that should be included in the IR plan?

Union lists as an example of a possible Z factor the return on equity formula.

a) Does PEG agree that a change in the Return on Equity Formula during the IR term is an appropriate Z factor? If not, why not?

b) If a Return on Equity Formula is changed during the IR term, would this necessitate a change in any of the components of the PCIs or RCIs as calculated by PEG? If so, please provide an explanation.

RESPONSE

a) No. The return on equity is a component of the price of capital. A change in the return on equity is thus an input price issue and should be addressed by the PCI inflation measure and any input price differential (IPD) that is part of the X factor formula. If Union seeks explicit protection for changes in the target ROE it should propose an industry specific input price index.

   PEG nonetheless has no objections to the periodic recalculation of he target ROE for reference purposes (*i.e.* not for use in rate setting during the IR plan) using a formula. This might reduce uncertainty concerning the target ROE that the Board might choose when rates are rebased upon the plan's expiration.

b) Yes, therefore Z factoring of the ROE might best be handled by recalculating the (fixed) input price differential before the plan begins.

Witness: Mark Lowry

IGUA #37

INTERROGATORY

Ref: Union Evidence, Ex.B, Tab 1, Schedule 1, page 5 of 22
Issue No.: 1.2
Issue: What is the method for incentive regulation that the Board should approve for each utility?

EGD alleges that the following objectives cannot be satisfied by a plan that does not adequately compensate the utility for the cost escalation and growth pressures it faces:

(a) Maintain a safe and reliable system;

(b) Meet service quality requirements;

(c) Retain incremental ROE resulting from efficiency improvement initiatives; and

(d) Respond to the continuing demand for new customer attachment, recently at a pace of 45,000 to 50,000 new customers per year.

In PEG's opinion, can these objectives be satisfied by both a PCI and an RCI? Please explain.

RESPONSE

The answer is yes, provided that the plan includes appropriate incentives for the maintenance of safety and quality standards. The chief difference between revenue caps and price caps does not lie here but rather in incentives for effective marketing and the question of who absorbs the risk of volume fluctuations.

Witness: Mark Lowry

IGUA #38

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 1, page 2 of 37
Issue No.: 3.1
Issue: How should the X factor be determined?

EGD's analysis of the X factor focused only on the geometric decay method and ignores the use of the cost of service method. Is it appropriate to ignore the cost of service method? If not, why not?

RESPONSE

No. The chief benefit of the cost of service (COS) method in our view is its ability to expedite the selection of an appropriate input price specification for the price cap index. The COS approach may also generate more relevant measures of productivity growth. For example, it might be more useful in examining the short run effect of cast iron replacement on TFP growth.

Witness: Mark Lowry

IGUA #44

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 2, page 18 of 24
Issue No.: 3.1
Issue: How should the X factor be determined

Dr. Carpenter states that PEG's reasoning that the prospects for the realization incremental scale economies by EGD is inversely related to initial operating scale is faulty. Dr. Carpenter states that at some point scale economies will plateau or be exhausted, particularly when incremental customers and volumes require the construction of greater miles of new distribution main per customer. Does PEG agree with these assertions? If not, why not?

RESPONSE

No. Our empirical finding that large gas distributors can still earn sizable incremental scale economies is consistent with economic theory.

Witness: Mark Lowry

IGUA #49

INTERROGATORY

Ref: EGD Evidence, Ex.B, Tab 3, Schedule 3, page 12 of 64
Issue No.: 3.1
Issue: How should the X factor be determined?

Dr. Bernstein states that omitting an X factor component designed to measure future changes in infrastructure expenditures that differ from past trends will lead to an incorrect X factor.

a) Does PEG agree with this statement? If not, why not?

b) In PEG's view, if X factors should be designed to measure future infrastructure expenditures, then should X factors also measure all other non-infrastructure-related future changes? Please explain.

RESPONSE

a) No. Accommodations of this sort can be reasonable for a company making major plant additions that cause a sizable discontinuity in its unit cost trajectory. An example might be a medium-sized utility that is bringing a sizable power plant into rate base. These kinds of discontinuities are comparatively rare for gas and electric power distributors because significant investments are required each year to connect new customers.

   As it happens, Enbridge hasn't made a convincing case that a major unit cost discontinuity is on the horizon. Its rapid customer growth should accelerate its productivity growth and not slow it. As for its cast iron replacements, cast iron accounts for a remarkably *small* percentage of the massive Enbridge system. And cast iron replacement can trigger a sizable acceleration in the productivity of operation and maintenance inputs. Our econometric work does not suggest that cast iron replacement has a significant impact on TFP growth.

b) This is a reasonable question since utilities have an incentive to single out for special treatment developments that may raise their unit cost but not developments that would lower them. With regards to cast iron, for instance,

Witness: Mark Lowry

the acceleration in O&M productivity that is likely to be triggered by replacements is a tandem issue. Regulators in some jurisdictions (*e.g.* Britain and Australia) finesse this problem by basing X on a multiyear forecast of *total* cost. Please note also that, if a company receives a special X factor adjustment for big investments, regulators should be attentive in the future to the need for special X factor adjustments to recognize a lack of big investments.