SUBMISSION TO THE PRODUCTIVITY COMMISSION *REVIEW OF THE GAS ACCESS REGIME: PRODUCTIVITY COMMISSION DRAFT REPORT*

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1. Introduction

The issue of productivity-based regulation (PBR) has arisen in the Productivity Commission's (PC's) Review of the Gas Access Regime.[1] Previous work on this topic in Australia has concluded that productivity-based regulation is theoretically superior to the building block approach to CPI-X regulation. The PC also says that implementing productivity-based regulation involves certain implementation issues that have not yet been resolved. Although the PC has supported productivity-based regulation in the past, the Draft Report concludes that there is little merit in undertaking further research on this topic.

I have been asked by the Essential Services Commission (ESC) of Victoria to prepare a submission on the issue of productivity-based regulation. My work is to address three main points: 1) to describe productivity-based regulation (PBR); 2) to evaluate the theoretical merits of PBR vis-à-vis the building block method; and 3) to present some practical, "real-world" experience with productivity-based regulation and other incentive regulation options that have not been used in Australia's energy utility industries. Providing concrete information on how regulatory alternatives have operated in practice will hopefully lead to greater insight into the feasibility and viability of such options for Australia's gas access regulation.

Overall, I believe productivity-based regulation deserves further examination. PBR has clear theoretical appeal. Conceptual analysis suggests that productivity-based regulation can foster long-run efficiency and create benefits for both shareholders and customers of Australia's natural gas utilities. This regulatory option also has a proven track record. While certain issues will inevitably arise with any change in regulation, there is little reason to believe that the issues associated with implementing PBR would be either insoluble or especially costly.

My submission is structured as follows. I begin by discussing some basic principles for evaluating regulatory regimes. I then describe productivity-based regulation and evaluate its merits as potentially applied in Australia's Gas Access Regime. I then discuss PBR precedents as well as alternative, incentive regulation options and tools. Next, I discuss an incentive power model that my firm, Pacific Economics Group (PEG), is developing and that may prove valuable in providing more rigorous assessments of regulatory options. Finally, I consider some recent experience with investment and regulation in the US natural gas industry, noting that a number of prior submissions to the PC claim that regulation tends to have a "chilling" effect.

[1] The acronym "PBR" also sometimes refers to "performance based regulation," which includes productivity-based regulation as well as other approaches. To avoid confusion, this submission will not use the term performance-based regulation and all references to PBR will mean productivity-based regulation.

2. Regulatory Principles

Economists believe that competitive markets often create the maximum benefits for society. The operative market forces of customer choice and producer competition create optimal incentives to behave efficiently. For example, firms in competitive markets that are not productively efficient have costs above the minimum. This leads to lower profits as sales are lost to more efficient rivals. Lower profits in turn, create pressures to reduce costs. Similarly, firms that choose non-optimal prices or do not produce the products that consumers demand lose sales to competitors. Profits thereby decline, leading to changes in marketing behavior that promote allocative efficiency.

Competitive markets also create strong incentives for dynamic productive and allocative efficiency (*i.e.* efficient investment and product development choices, respectively). One reason is that competitive markets typically use available information more effectively than more centralized economic structures. Dynamic efficiency requires knowledge of how customers' demands are changing and how to invest to respond to the evolving marketplace. Competitive markets naturally create these incentives as firms continuously endeavor to stay ahead of their rivals.

While economists agree that that competition is more effective than regulation in promoting efficiency and long-term customer benefit in most markets, it is equally clear that this is not always the case. When industries are "natural monopolies," it is more efficient for a single firm to provide service to the entire market than to allow the service to be provided competitively by multiple firms. Firms with monopoly franchises can exert monopoly power that would undermine economic efficiency, so such utilities are subject to price and quality regulation.

When regulation is implemented, the regulator serves as a surrogate for market forces. Regulation can promote greater efficiency in the provision of utility services by attempting to replicate the same market-based forces and outcomes that prevail in competitive markets. This can be done through "high powered" incentive regimes that decouple allowed prices from a firm's actual costs, at least for a period of time. Firms accordingly bear a greater degree of risk to changes in their cost structure than under more "low powered" incentive plans.

Optimal regulation would encourage utilities to realize the maximum efficiencies that are inherent in the production technologies of the services they are providing. Since utilities subject to a given regulatory regime will achieve this goal with different degrees of success, a company's returns under high-powered regulation would be commensurate with its *performance*. More efficient firms would earn higher returns, while less efficient firms would have lower returns. This parallels the outcomes of competitive markets, where some firms outperform their rivals even in the long run. High-powered regulation will therefore not attempt to impose the same returns on all firms, since that penalizes good managers and subsidizes bad ones. It will also not create explicit links between returns and risks. Such a direct link naturally presupposes a cost-based, and therefore low-powered, regulatory scheme.

At the same time, regulators try to ensure that customers share in the benefits of realized efficiency gains. This also parallels the outcomes of competitive markets. Market-based forces naturally lead industry-wide gains in efficiency to be passed on to customers as price declines.

However, regulators' face a dilemma in attempting to satisfy these twin objectives. Transferring benefits to customers undercuts companies' incentives to undertake actions that lead to efficiency gains in the first place. Regulators therefore face a tradeoff in trying to create incentives for utilities to behave efficiently and in ensuring that customers benefit from efficiency gains. Optimizing this tradeoff is central to regulation.

Regulators may also face a tradeoff with respect to incentives and risk. As noted, high-powered incentive regimes create stronger performance incentives but also entail greater risk. Low-powered regulation reduces incentives but also mitigates risk. Regulators must be cognizant of investors' risk perceptions since these will influence the amount of investment that takes place in the industry, as well as the terms on which investors are willing to provide capital. Investment, in turn, is critical to both the efficiency and quality of utility services, particularly in the long run.

These tasks are inherently complicated, and they are made more so by the information asymmetries that exist between regulators and the firms they regulate. If regulators knew the efficient way to produce and market utility services, they could simply mandate the optimal array of services and set prices to recover the minimum cost of providing them. Unfortunately, it is often difficult for even 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 know much less about the utility business. Accordingly, regulators' efforts to set appropriate prices requires substantial exchange, processing, and analysis of utility cost and sales data. These actions are costly to both the regulator and the utility and can create yet another tradeoff – between regulators' attempts to replicate the efficient behavior and outcomes of a competitive market and the regulatory costs that are incurred through these efforts.

Regulation therefore involves a number of delicate balances. Regulators attempt to satisfy objectives that include encouraging economic efficiency (including efficient investment), ensuring that customers benefit from efficiency gains, mitigating risk, and minimizing regulatory costs. Some of these goals are likely to be in conflict. A given regulatory approach will be preferred to the extent that it satisfies all these objectives but, in practice, consideration will have to be paid to the tradeoffs associated with achieving different regulatory aims.

3. Productivity-based regulation

Productivity-based regulation is by now a well-established technique. It has been used for over 20 years in a variety of US industries. It has more recently been applied in jurisdictions including Canada, Argentina, and Colombia. The bundled power utility in Jamaica also operates under a License specifying a CPI-X plan where the X factor formula is calibrated using the company's expected total factor productivity (TFP) growth. Most recently, New Zealand established a CPI-X regulatory "thresholds" regime, where the X factor was set using information on the industry's (and New Zealand economy's) TFP growth trend. The New Zealand Commerce Commission considered setting the terms of the CPI-X formula using a building block approach but rejected this option. In describing PBR precedents, I will focus only on US energy utility examples since this experience is more relevant (compared with telecom or railroad precedents) and extensive (than other countries using PBR).

3.1 Basics

Although rate indexing is associated in the minds of many with Great Britain, the United States has a similarly long history with this regulatory system. The approach that has become common in America was outlined in a 1979 paper by E. Fred Sudit of Rutgers University.[2] [3] William Baumol, then at Princeton University, elaborated on the idea in a 1982 paper.[4] The American approach was influenced by these early treatises, but credit must also go to regulators in early regulatory proceedings and supporting legislation.[5]

The American approach is based on the premise that utility regulation should mimic the outcome of competitive markets. The trend in the prices charged by a competitive industry is the trend in its unit cost. The benefits of productivity growth are then passed to customers over time in the form of slower price growth. Because the *industry* unit cost trend is insensitive to individual firm actions, companies in competitive markets have strong incentives to slow unit cost growth.

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[2] E. Fred Sudit, "Automatic Rate Adjustments Based on Total Factor Productivity Performance in Public Utility Regulation", in *Problems in Public Utility Economics and Regulation* ed. M. Crew, Lexington Books, 1979.

[3] Sudit subsequently collaborated with Michael Crew and Paul Kleindorfer on an alternative approach to index based regulation that has not to our knowledge been implemented. In this approach, the utility nominates the X-factor that is used in the plan. A mechanism is proposed that incents the company to base its nomination on its TFP growth expectation.

[4] William J. Baumol, "Productivity Incentive Classes and Rate Adjustment for Inflation", *Public Utilities Fortnightly*, July 22, 1982, pp. 11-18.

[5] The earliest price indexing plans approved in the United States emerged from hearings before federal regulatory commissions in the 1980s. An indexing plan was first approved in 1981 for certain services of Class I railroads. This predates both Stephen Littlechild's famous 1983 paper on the merits of RPI-X indexing and the first UK application of RPI-X regulation to British Telecom in 1984. For more detail on the history of rate indexing in the US and the UK, see Kaufmann, L. and M.N. Lowry, *Updating Price Controls in Victoria: Analysis and Options*, June 1997, Report to the Office of the Regulator General in Victoria, Australia.

The logic behind this important result merits explanation. A central result of index logic is that if an industry earns, in the long run, a competitive rate of return, the growth trend in an index of the prices it charges (its output prices) will equal its unit cost trend.

$$trend\ Output\ Prices^{Industry} = trend\ Unit\ Cost^{Industry}. \quad [1]$$

It can be shown that the trend in an industry's unit cost is the difference between trends in its input price index and its TFP index.[6]

$$trend\ Unit\ Cost^{Industry} = trend\ Input\ Prices^{Industry} - trend\ TFP^{Industry}. \quad [2]$$

It should be emphasized that the TFP index above corresponds to that for the relevant utility industry. This is necessary for the allowed change in prices to conform with the competitive market paradigm. In competitive markets, prices change at the same rate as the *industry's* trend in unit costs and are not sensitive to the unit cost trend of any individual firm.

However, it should be noted that industry TFP trends are necessarily estimated using the industry's historical data. Many utility industries have historically been subject to lower-powered regulatory schemes, like rate of return regulation. Economists generally believe that rate of return regulation does not create optimal incentives to contain unit cost. Industry TFP and input price trends calculated from historical data will naturally reflect the industry's historical unit cost performance under these low-powered regulatory mechanisms.

Rate indexing is designed to create stronger performance incentives than traditional regulation. Superior incentives should lead, in turn, to more rapid TFP growth relative to historical norms. Regulators recognize this, and rate indexing plans typically incorporate what are called either "consumer dividends" or "stretch factors" to reflect the expectation that TFP growth will increase under PBR, and consumer prices should reflect some of the benefits of this expected growth.

US PBR plans have used two main approaches for selecting an external inflation factor. One general approach is to use a measure of economy-wide inflation such as those prepared by government agencies. Examples include the Price Index for Gross Domestic Product (GDP-PI) and the U.S. Consumer Price Index (CPI). Inflation

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[6] Here is the full logic behind this result:

$$\begin{aligned}
\text{trend Unit Cost}^{\text{Industry}} &= \text{trend Cost}^{\text{Industry}} - \text{trend Customers}^{\text{Industry}} \\
&= \left(\textit{trend}\ \text{Input Prices}^{\text{Industry}} + \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&\quad - \textit{trend}\ \text{Output Quantities}^{\text{Industry}} \\
&= \textit{trend}\ \text{Input Prices}^{\text{Industry}} \\
&\quad - \left(\text{trend Customers}^{\text{Industry}} - \textit{trend}\ \text{Input Quantities}^{\text{Industry}}\right) \\
&= \text{trend Input Prices}^{\text{Industry}} - \textit{trend}\ \text{TFP}^{\text{Industry}}.
\end{aligned}$$

factors in Australian and British indexing plans have almost exclusively used economy-wide inflation indexes.

The primary advantage of an economy-wide inflation factor is its simplicity. Such inflation measures are also credible since the indexes are computed by respected government agencies. The main concern is that economy-wide price inflation may not reflect price trends for inputs purchased by the regulated industry. This is particularly true over short time frames.

An established alternative in US plans is to construct an index of external price trends for several inputs used by utilities. This approach is expressly designed to measure input price inflation of the regulated industry.[7] Such industry-specific inflation measures have been approved in indexing plans for Pacificorp-California, Southern California Gas, and San Diego Gas and Electric.

By design, an industry-specific inflation measure tracks fluctuations in industry input prices better than an economy-wide index. Industry-specific inflation measures should therefore reduce business risk. The main disadvantage with this approach is its complexity. Since input price trends for utility industries are often not computed by official sources, utilities must develop inflation factors that reflect growth in the industry's input prices. Appropriate input price indexes can be constructed from publicly-available data and, as noted above, have in fact been approved in some plans.

Our exposition of this analytical framework helps to explain some major issues that are addressed in American price indexing proceedings. One is the TFP trend of the industry. A second is the success with which proposed inflation measure tracks industry input price inflation. A third is the appropriate benefit sharing mechanism, which will in most cases involve choosing a value for the consumer dividend. The X-factor can in principle reflect all three considerations. [8] [9]

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[7] The first US example of this is the Index of Railroad Cost in the railroad rate indexing plan. The growth rate in this index is a weighted average of the growth rates in external indexes of the prices of railroad inputs. There are separate categories for labor, fuel, materials, equipment rentals, depreciation, interest, and miscellaneous inputs. The weights are the shares of the inputs in the applicable total cost of the railroad industry. Because of this initial precedent, this kind of inflation measure is sometimes said to be of "railroad style".

[8] For example, a consumer dividend can be added directly to the industry TFP trend so that the X factor is the sum of the industry TFP trend plus the consumer dividend. The logic involving terms that allow the inflation measure to track the industry input price trend better is somewhat more complex. Many firms use broad measures of economy-wide inflation, like the GDP-PI, as an inflation factor in indexing plans. If the trend growth in GDP-PI is both added and subtracted from the right hand side of equation [2] above, this equation is unchanged. Doing so yields the following formula

$$trend\ Unit\ Cost^{Industry} = trend\ GDPPI - \begin{bmatrix} trend\ TFP^{Industry} \\ + \left(trend\ GDPPI - trend\ Input\ Prices^{Industry}\right) \end{bmatrix} \qquad [3]$$

3.2 Potential Merits of Productivity-Based Regulation

The main difference between a building block and productivity-based approach to setting price changes in CPI-X regulation is that the latter is calibrated on the basis of *industry* TFP trends and not a company's own expected costs.[10] Industry performance measures are distinct from and "external" to the performance of any individual firm. Setting the terms of indexing plans on the basis of industry TFP measures is therefore an arguably more high-powered form of regulation since it creates less of a link between a regulated firm's own costs and its allowed prices. The economic literature clearly indicates that the strength of incentives, and associated "power" of a regulatory regime, depends on the extent to which prices and costs are de-linked.[11]

The items in the bracketed term can be further decomposed by recognizing that the GDP-PI is a measure of *output* price inflation in the overall economy. Given the broadly competitive structure of our economy, the same indexing logic detailed in equation [1] and [2] will also apply to the measures of economy-wide output price inflation. This logic implies that the long-run trend in GDP-PI is the difference between the trends in input price and TFP indexes for the economy.

$$trend\ GDPPI = trend\ Input\ Prices^{Economy} - trend\ TFP^{Economy}\ . \qquad [4]$$

Substituting [4] into [3] implies that

$$trend\ Unit\ Cost^{Industry} = trend\ GDPPI - \begin{bmatrix} \left(trend\ TFP^{Industry} - trend\ TFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) \end{bmatrix} \qquad [5]$$

If the GDP-PI is used as an inflation factor, the bracketed expression corresponds to the X factor. This result shows that the X factor should be calibrated to reflect *differences* in the input price and TFP trends of the relevant utility industry and the economy. The productivity differential will be the difference between the TFP trends of the industry and the economy. X is more apt to be positive, slowing allowed price growth, when industry TFP growth exceeds the economy-wide TFP growth embodied in the GDP-PI. The inflation differential is the difference between the input price trends of the economy and the industry. X will tend to be larger (smaller) when the input price inflation of the economy is more (less) rapid than that of the industry.

[9] Some indexing plans also apply comprehensive indexes to revenues rather than prices. Rather than limiting the escalation in an index of utility prices, revenue caps limit revenue growth. A growth rate formula for a revenue cap index requires an adjustment to reflect the effect of output growth on cost. An explicit term for such an adjustment may be called an output factor and denoted by *Y*. An index-based restriction on revenue requirement growth may then be written

$$\%\ \Delta\ Revenue\ Requirement\ =\ P\ -\ X\ +\ Y\ \pm\ Z\ .$$

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 measure, *Y*.

[10] In this submission, I will not consider the issue of whether building blocks may play a role in setting initial prices in an otherwise productivity-based regulatory regime. As the Essential Services Commission submission discusses, there are many possible ways in which building blocks and productivity-based regulation can in principle interact, and the Commission will be commencing research on this and related topics. A complete discussion of these complex topics is therefore premature and beyond the scope of this submission.

[11] For example, see J. Laffont and J. Tirole (1998), *A Theory of Incentives and Procurement*, MIT Press, Cambridge, MA.

Compared with a building block approach, productivity-based regulation can simultaneously enhance performance incentives, facilitate marketing flexibility, and reduce regulatory cost. Because PBR-based prices are set using external data, unit cost reductions do not decrease allowed rate escalation but go straight to the bottom line. This creates optimal incentives to control costs.

Productivity-based regulation may further enhance performance by allowing many operating restrictions to be relaxed. This is especially true of marketing flexibility. When utility revenues are based on external indexes rather the company's own costs, prices of monopoly services can be insulated from the company's involvement in competitive markets. This reduces concerns about cross subsidies and the impact of uncertain competitive market initiatives on core customer tariffs. Light-handed regulation of non-core services is then possible. A company can also have more leeway in its purchases from affiliates and in its depreciation policies.

Productivity-based regulation can also have a beneficial effect on regulatory compliance cost. The cost and contentiousness of regulatory reviews can be substantially reduced. Unlike the building block approach, reviews can focus on industry TFP and input price trends rather than detailed examinations of company costs. Detailed cost reviews expose regulators to the same information asymmetries that are the heart of problems with traditional, US cost of service regulation. These information asymmetries may be especially pronounced under the building block approach since prices are set using information on the company's past cost performance and, more importantly, it's expected growth in costs. Evaluating cost forecasts, particularly for capital expenditures, is an inherently difficult and uncertain exercise. Regulators' challenge in evaluating whether future cost projections are inflated is exacerbated by the fact that they know much less than company managers about the underlying utility business and its outlook for demand, cost and technological growth.

Productivity-based regulation also encourages utilities to discover new uses for their assets and expertise in related markets. Accordingly, it can be instrumental in facilitating efficient diversification and new product development. Such long-run benefits are examples of dynamic efficiency.

The potential for gas utilities to exhibit dynamic efficiency, be innovative and introduce new products can perhaps be made more concrete through an example. It should be emphasized that this example is illustrative only and does not imply that any Australian utilities are currently considering such an initiative or would pursue it under productivity-based regulation. However, it will hopefully demonstrate that certain innovative and creative practices will be much more feasible under PBR than under building blocks regulation.

There are currently field demonstrations examining the feasibility of inserting fiber optic lines in "live" gas lines. This could prove to be a much cheaper method of installing the "last mile" of fiber optic networks in urban areas. The "last mile" installation costs have generally been prohibitively expensive for most end-users but, by using existing infrastructure, installing fiber optics in gas delivery networks could make the extension of the fiber optic network more economically feasible.

I believe such a project is more feasible under productivity-based regulation than building blocks CPI-X regulation. Gas distributors subject to productivity-based regulation would evaluate the merits of renting space in their gas lines by evaluating the incremental revenues they would earn relative to the incremental costs they would incur. Under building blocks, companies would also examine these incremental costs and revenues but would have to consider a host of related regulatory issues that would not arise under productivity-based regulation. For example, the utility would have to consider whether any incremental revenues they earn would have to be given back to customers. The company may also have to project the costs and revenues associated with this service in future regulatory periods. Such forecasts for a new service would be highly speculative. It would also not be possible to finesse the regulatory issues by undertaking this activity through an unregulated subsidiary, since the project necessarily uses utility infrastructure. Under productivity-based regulation, however, there are fewer regulatory concerns or unknowns, since the company's allowed prices would be set for a known, multi-year period by an external formula rather than on its own costs or revenues. It is therefore more likely that such a long-run, dynamically efficient project (if deemed to be commercially viable) will be pursued under productivity-based than building blocks regulation.

I also believe that most of the "Costs of the current Gas Access Regime" that are identified in the Draft Report (p. 256) can be reduced with productivity-based regulation.[12] For example:

- *the high potential for regulatory error* may be reduced by decreasing the number of variables on which the regulator must make decisions (*e.g.* the various cost components and projections in the building block approach) to a much smaller but more comprehensive set of performance measures (chiefly industry TFP and input price trends)
- *high regulatory risk* may be similarly contained by reducing the number of regulatory parameters and specifying more clearly the formulas that will be used to calculate industry TFP and input price trends
- *high compliance costs* and *time delays*, as discussed above, can be reduced
- *the distortion of investment* via asymmetric truncation of returns can also be contained. As noted, productivity-based regulation is an example of external regulation where the terms of the CPI-X formula are largely insensitive to the actions or performance of an individual firm. A firm's actual profits or losses depend on its success in managing its own TFP growth relative to the targets embodied in the price controls. Gains that result from higher productivity

[12] However, some of these costs go beyond the issue of whether the method of regulation is based on building blocks or productivity-based regulation.

growth are treated symmetrically with losses stemming from poor productivity performance.

- *regulatory gaming and lobbying* As discussed above, the incentives and potential to engage in regulatory gaming under the building block method are strong. This potential is greatly ameliorated under PBR since the firm's allowed prices depend on industry performance measures that any individual firm has little if any ability to manipulate for regulatory proceedings.
- *limited guidance from economic theory* and *difficult to apply regulation objectively* Productivity-based regulation has a strong foundation in economic theory and is explicitly designed to emulate the incentives and outcomes of a competitive marketplace.
- *the incentive for regulators to overregulate* by increasing the amount and complexity of information in order to fix regulatory deficiencies may also be reduced; again, PBR represents a relatively "clean" and straightforward approach that focuses on a few, comprehensive regulatory parameters.

I also believe that other sections of the Draft report recognize that productivity-based measures can be important for streamlining and improving gas access regulation. In fact, the Draft Report recommends that TFP measures be used as part of the price monitoring option the PC wants to add to the Regime. I believe that TFP trend measures can do more than simply play a monitoring role; they can also form the core of an alternative regulatory approach for setting gas access reference prices. The theoretical merits of PBR are buttressed by the ample experience (discussed below) demonstrating the effectiveness of this approach in energy utility regulation.

At the same time, it should be recognized that productivity-based regulation does have certain disadvantages. The biggest such concern is business risk, or the possibility that price controls will not track trends in external business conditions that affect a company's costs. Relevant business conditions include weather, the business cycle, prices of competing energy products, and government policy. Windfall gains and losses occur to the extent that allowed prices do not reflect changes in these conditions. This higher business risk is the other side of the coin of a high-powered regulatory regime. As I discuss later in the next section, many of these risks can be mitigated through careful design of productivity-based regulation plans.

3.3 Precedents

While many US energy utilities are still subject to cost of service regulation, a number of indexing plans have been approved for US energy utilities. Consistent with the US approach to CPI-X regulation, TFP evidence has been important in nearly all of these plans. Below I briefly describe ten such plans, emphasizing the role of productivity evidence and the final X factors that were approved.[13] [14]

- the comprehensive power services of Pacificorp-California
- the comprehensive power services of Central Maine Power
- the power distribution services of Central Maine Power (after the Maine electric utility industry was regulated and competition introduced for power generation services)
- the power distribution services of Southern California Edison
- the gas distribution services of Southern California Gas
- the power distribution services of San Diego Gas and Electric
- the gas distribution services of San Diego Gas and Electric
- the gas distribution services of Berkshire Gas (Massachusetts)
- the gas distribution services of Boston Gas
- the updated plan for Boston Gas

California

The first indexing plan for energy utilities in California was approved in late 1993 for PacifiCorp. This plan featured an industry-specific inflation measure. The X-factor in this plan was based on the company's own long-run TFP trend. This TFP trend was computed by the Office of the Ratepayer Advocates, which is a part of the California Public Utilities Commission (CPUC). The initial X-factor was set at the company's long-term TFP trend of 1.4%. In 1997, this TFP trend was updated to include the three most recent years of Pacificorp's TFP performance. The resulting X-factor was 1.5%. No consumer dividend was added to this long-run TFP trend when setting the X factor.

[13] It may be interesting to note that, in the ten other plans listed, PEG personnel have provided TFP evidence in seven. The exceptions are for Pacificorp-California (where the TFP studies were done by a division of the California Public Utilities Commission), Southern California Edison (done by the Company itself), and the power distribution plan for Central Maine Power. The Berkshire Gas plan used our previous study for Boston Gas.

[14] It may also be noteworthy that index-based price plans have also been widespread in the Canadian province of Ontario. For example, the Ontario Energy Board (OEB) has approved a CPI-X plan for power distributors in the Canadian province of Ontario. The OEB adopted a competitive market paradigm when setting the terms of the CPI-X formula. It wrote "PBR (performance-based regulation) is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behavior which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies" (Ontario Energy Board, *Decision With Reasons*, RP-1999-0034, January 18, 2000, p. 13). The X factor in this plan was based on the TFP trend for the Ontario power distribution industry. These TFP studies were done for the OEB. The OEB examined both the five-year and ten-year trend when deciding on an industry TFP measure. It believed more weight should be placed on the longer-term trend but some weight should also be applied to more recent experience. It applied a two-thirds weight to the 10-year trend and a one-third weight to the five-year trend. This led to an industry TFP growth rate of 1.25%. A 0.25% stretch factor was added to this to arrive at an overall X factor of 1.5%.

The first CPI-X regulation plan approved for a North American power distributor was for Southern California Edison (SCE). This plan took effect in 1997. The inflation measure was the US CPI. The X factor in this plan rises from 1.2% in 1997 to 1.4% in 1998 and 1.6% in 1999-2001. This X factor was based on a TFP study that the company conducted of its TFP growth. This study showed that SCE's long-term TFP growth trend was 0.9% per annum. The Commission accepted this estimate. The overall X factor therefore reflects this TFP trend plus consumer dividends that rise from 0.3% to 0.7% over the plan, with an average value of 0.56%.

In approving this plan, the California Public Utilities Commission (CPUC) said it would have preferred to use industry TFP measures as the basis for the X factor. However, no party in SCE's preceding presented evidence on industry TFP. The CPUC espoused a competitive market standard as the rationale for its preferred approach. It wrote:

> The 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.[15]

The plan approved for Southern California Gas (SCG) represents the first approved for a California energy utility that used industry TFP research. SCG commissioned a study from PEG personnel that showed a TFP trend for the US gas distribution industry of 0.5% per annum. In reviewing this study, the CPUC staff was interested in developing its own TFP estimate and asked for the data used in the study. These data were compiled from publicly-available sources, but they were collected by PEG personnel themselves and are not available from a centralized source. The data were provided to the CPUC staff subject to a confidentiality agreement, and the staff proceeded to conduct its own TFP study. The staff's estimated TFP trend for the industry was identical to the 0.5% proposed by SCG. In light of this experience, the CPUC approved a 0.5% figure for industry TFP growth and ruled that this figure "elicited little criticism from the parties."[16]

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[15] Application of Southern California Edison to adopt a Performance Based Rate Making Mechanism Effective January 1, 1995, Alternate Order of Commissioners Fessler and Duque, July 21, 1996.

[16] Decision 97-07-054, *In the Matter of the Application of Southern California Gas Company to Adopt Performance Based Regulation for Base Rates*, July 16, 1997. It should be noted, however, that there was less agreement on other elements of the X factor. SCG proposed a 0.5% consumer dividend, but the CPUC approved dividends that rose from 0.6% to 1.0% throughout the plan. The CPUC also added a 1.0% increment because SCG's capital stock was projected to decline during the plan. This is a fairly unique situation, and it is the only such instance of a North American CPI-X plan including an increment for a declining rate base.

San Diego Gas and Electric (SDG&E) was the first indexing plan approved for both the gas and power distribution operations of a combination utility. The company commissioned PEG personnel to estimate industry TFP trends in both power distribution and gas distribution. Our TFP trends were 0.68% and 0.92% per annum for gas and power distribution, respectively. The CPUC accepted this evidence and added an average consumer dividend of 0.55% per annum to each plan. The average X factors for gas and power distribution were therefore 1.23% and 1.47%, respectively.

Maine

TFP evidence has been presented in the two approved indexing plans for Central Maine Power. In both cases, however, the final terms of the indexing plans resulted from a settlement reached between proposals that were put forward by different parties. This settlement process is probably somewhat unique to US regulation, and to make it more concrete I will describe the regulatory process for the first CMP plan in some detail.

The first CMP indexing plan grew out of a rate case that was brought before the Maine Public Utilities Commission in December 1992. In its final Order in December 1993, the Commission approved a modest rate increase but also concluded that the efficiency and cost-cutting efforts of CMP were inadequate. It directed CMP and other parties to develop a price cap plan that provided stronger incentives to operate efficiently.

The original CMP indexing proposal was presented in June 1994. The Company proposed to use an indexing mechanism to set rates for the 1995-99 period. The inflation factor was to be the change in the Consumer Price Index (CPI) for all Urban Consumers.

No X factor would be applied in the first two years of the plan. The X factor in each year from 1997-99 would equal to one-third of the CPI growth rate. Given projected inflation trends, this would have created an X factor in these years of about 1%. This X factor was deemed to be reasonable in light of TFP evidence the Company presented that showed industry TFP growth in the provision of comprehensive power services that was slightly below 1% per annum. However, indexing would not apply to several important classes of expenses (DSM costs, restructured purchase power contracts and one-half of the costs related to a change in accounting procedures for post-employment benefits), which were to be treated as “Z factors,” or items whose costs could be passed through directly to prices subject to regulatory approval of final costs.

Coincident with the CMP proposal, another price cap plan was developed by a consortium of interested parties. This plan became known as the Public Party/Customer Proposal (PPCP). Minor modifications of this plan were suggested by some groups, but the PPCP was essentially a consensus counterproposal that enjoyed broad support among Commission staff and major intervenor groups.

The PPCP featured the fixed-weight deflator for Gross Domestic Product (GDP-PI) as the inflation measure. The X factor increased over the term of the plan from 0.5% in 1995 and 1996 to 1.0% in 1997 and 1.5% in 1998-99.

The PPCP also contained a long list of Z factors. The items proposed by CMP were also recommended as Z factors in the PPCP. In addition, Z-factor treatment was to be afforded to the deferral of Electric Revenue Adjustment Mechanism (ERAM) balances, 50% of the margins from (FERC-regulated) bulk power, cost changes that result from variation in capacity factors at plants where CMP purchases power, and amortizations of CMP's cancelled plant.

In October 1994, a Stipulation was agreed to between CMP and the parties represented in the PPCP. This agreement resembled the PPCP more than the CMP proposal. However, the Stipulation contained important modifications of the PPCP and several features that were not present in either proposal. The Commission approved this stipulation without modification.

The GDP-PI was selected over the CPI as the inflation measure for three reasons. First, the GDP-PI is a more accurate index of economy-wide inflation by virtue of tracking prices for a greater number of goods and services. Second, the GDP-PI utilizes more recent data to weight individual service prices in computations of the index. Finally, the Commission concluded that the GDP-PI has been less volatile than the CPI in recent years.

The X factor was to be 0.5% in 1995 and 1.0% in 1996-99. These values were lower than had been proposed in the PPCP. The items to be afforded Z-factor treatment were essentially the same as that proposed by CMP.

The application of the indexing formula was different than either party had proposed. CMP wanted the index to apply to the entire rate, while the PPCP applied the index to base rate changes only and set fuel rates through a complex system of fuel cost projections and reconciliations. In the final agreement, the index was applied to the entire rate but there was a "QF adjustment" to reflect the fact that some of CMP's purchased power costs were not sensitive to aggregate inflation trends. In practice, the QF adjustment was to be implemented by multiplying the change in the index due to the inflation, X and Z factors by (1-.375). The value selected for the QF adjustment was based on the judgment that 37.5% of CMP's costs are not affected by inflation.

A somewhat similar outcome occurred in the power distribution plan that was approved for CMP in 2000. The Company's proposal also featured TFP evidence The final terms of CMP's CPI-X plan were again reached in a stipulation agreement between most interested parties. The Maine Public Utilities Commission only had to decide whether or not to approve this stipulation and did not have to make a specific finding on the industry TFP trend. However, the approved X factors, ranging from 2% to 2.9% over the course of the plan, were nearly identical to those proposed by the Office of the Public Advocate and were substantially different from those supported by CMP. It should be noted, however, that part of this X factor included merger savings from a merger that CMP recently concluded. This is obviously a unique situation and represents "productivity" gains well in excess of those that would typically be reflected in the TFP trend or X factor.

Massachusetts

A rate indexing plan was approved for Boston Gas (BoGas) in Massachusetts in 1997. The X factor approved for BoGas had four components: a TFP differential (*i.e.* the difference between industry and economy-wide TFP trends), an input price differential (*i.e.* the difference between economy-wide and industry input prices), a stretch factor, and an accumulated inefficiencies factor. The first two of these components reflect the indexing logic previously presented when an economy-wide inflation measure is employed as the inflation factor. This was the case for Boston Gas, whose proposed inflation factor was the gross domestic product price index (GDP-PI), the official measure of GDP price inflation.

The Massachusetts Department of Public Utilities (DPU) approved an overall X factor of 1.5%. The approved TFP trend for the gas distribution industry was 0.4%, which was a proxy for the trend in the regional gas distribution industry. The Commission agreed that the industry for the region (the Northeast United States) was distinct from that of the rest of the country because of evidence of different cost pressures in the Northeast. This TFP evidence was provided by PEG personnel. The *economy*-wide TFP trend was 0.3%, so the TFP differential between the industry and the economy was 0.1%. The input price differential was measured to be –0.1%. Input prices in the industry were therefore shown to be growing 0.1% less rapidly than economy-wide input prices. The sum of the TFP and input price differentials was therefore zero.

The approved consumer dividend was 0.5%. A fourth "accumulated inefficiencies" factor was also added that was equal to 1.0%. This factor is unique to Massachusetts, and it is designed to reflect the accumulated inefficiencies of operating under cost of service regulation, which purportedly encouraged inefficient practices. The Massachusetts Commission first approved an accumulated inefficiencies factor of 1% in the indexing plan for the state's telecom utility, NYNEX-Massachusetts. BoGas subsequently appealed the accumulated inefficiencies factor to the courts, which agreed that it had no evidentiary basis and ordered it to be eliminated. The final X factor in this plan was therefore 0.5%.

The industry TFP and input price evidence was later used in an indexing proposal by Berkshire Gas. Unlike Boston Gas, Berkshire Gas is a relatively small gas distributor. It argued that it would not be cost effective for it to undertake a separate

TFP study to support its X factor, and that the outcome of such a study would probably not differ dramatically from that presented by Boston Gas in any case. Berkshire therefore took the zero value for the combined TFP and input differentials in the Boston Gas case as the starting point for its X factor.

The final X factor for Berkshire also included a consumer dividend of 1%, so the overall X factor in this plan is 1%. While this is at the high end of approved consumer dividends in US indexing plans, the Berkshire plan does not contain an earnings sharing mechanism, so it is reasonable for the value of the consumer dividend to be higher since it is more important in ensuring that customers benefit from performance gains that may occur under the plan. In addition, the Berkshire plan may be in effect for as long as 10 years, which creates stronger performance incentives than most indexing plans that have terms between three and five years. All else equal, stronger performance incentives should lead to a greater acceleration of TFP under the indexing plan relative to the industry's historical norms, which in turn tends to support a higher value for the consumer dividend. Berkshire had also recently consummated a merger, and the consumer dividend may have partly reflected anticipated merger savings.

The most recently approved indexing plan in Massachusetts was for Boston Gas. PEG personnel again provided TFP evidence and formal testimony in support of the plan. The X factor formula was identical to that approved in the original plan, except for the elimination of the accumulated inefficiencies factor. The approved TFP trend for the Northeast gas distribution industry was 0.56%. The TFP trend for the US economy was 0.77%, so the TFP differential was -0.21%. The input price differential approved by the Commission was 0.3%. The consumer dividend was 0.3%. The overall X factor was therefore 0.41% (-0.21% + 0.3% + 0.3% = 0.41%). Like the Berkshire plan, the term of the Boston Gas plan was also 10 years.

Industry TFP and Stretch Factors

It may be valuable to review the approved TFP and stretch factors in indexing plans for North American energy utilities.[17] Below we present the industry TFP and stretch factors approved in the eight comprehensive indexing plans for which North American regulators made specific findings on these elements.[18]

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[17] There are many precedents for stretch factors in North American regulation. The first such factor was in the price indexing plan approved by the US Federal Communications Commission (FCC) for AT&T in 1988. The approved stretch factor in this plan was 0.5%, which was equal to 20% of AT&T's estimated TFP growth of 2.5%. In both the original and updated PBR plans for the interstate services of Local Exchange telecom carriers, the FCC also imposed stretch factors of 0.5%. These values were again equal to approximately 20% of the industry's estimated TFP growth.

[18] This includes two plans from Canada that are not discussed in this report. Also, as discussed earlier approved X factors in some plans were determined via negotiation among various interested parties. The stretch factors here are also average stretch factors over the term of the plan; in some cases, the value of the stretch factor differs during the term of the plan.

Company	Jurisdiction	TFP	Stretch
Southern California Edison	California	0.90%	0.56%
Southern California Gas	California	0.50%	0.80%
San Diego Gas and Electric – Gas	California	0.68%	0.55%
SDG&E-Electric	California	0.92%	0.55%
Boston Gas	Massachusetts	0.40%	0.50%
Boston Gas-update	Massachusetts	0.56%	0.30%
Berkshire Gas	Massachusetts	0.40%	1.00%
Ontario power distributors	Ontario, Canada	1.25%	0.25%
Union Gas	Ontario, Canada	0.90%	0.50%
Average		0.72%	0.56%

It can be seen that the average TFP trend in these plans is 0.72% and the average stretch factor is 0.56%. Both the TFP trend and stretch factors in these plans fall in a relatively narrow range. This experience clearly shows that there has been a high degree of convergence among the TFP trends that were estimated in these plans, although power distribution TFP is growing somewhat more rapidly than gas distribution TFP. This consistency is even more remarkable since it comes from different time periods and different countries (*i.e.* Canada and the United States). Perhaps even more surprising is the similarity in approved consumer dividends. All consumer dividends average between 0.25% and 1.0% per annum, and most are equal to or only slightly greater than 0.5%.

Assessments of US PBR Precedents

I believe the experience summarized above is generally positive. It suggests that TFP is a well-accepted technique and has tended to produce stable results in repeated applications. There has also been little controversy in these plans about whether past TFP growth is a good proxy for expected TFP growth. In part, this is because X factors in these plans include a (firm specific) stretch factor that reflects the company's expected TFP acceleration relative to the industry's historical norms. The value of this consumer dividend has typically been set by judgment, but the update of the Boston Gas plan did present econometric and accounting evidence on the impact that the company's last PBR plan had on its cost performance. The Commission accepted this evidence as the basis for the 0.3% consumer dividend/stretch factor approved in the updated plan.

Another reason why an industry's historical TFP trend has been viewed as a reliable guide to future TFP growth is that these TFP trends have, in fact, been fairly stable. This partly reflects the nature of the industries. Most plans have been approved for gas and power distributors, and output and investment growth in these industries is often, although not always, relatively stable over time. This is less true for power and gas transmission companies. Investments in these industries provide for bulk energy transfers from supply sources to large energy users and distribution points. Such large investments tend to be "lumpier" compared with energy distribution infrastructure, which is more often added in smaller increments in response to customer and demand growth. All else equal, a period when large, lumpy investments are made will be one where input quantity growth expands rapidly and TFP growth (equal to the difference between output and input quantity growth) accordingly declines. By the same token, a period where investments are either not necessary or are not undertaken is more likely to register relatively rapid TFP growth. The lumpiness of investment is therefore likely to make TFP trends in the power and gas transmission industries less stable than for either power or gas distribution. This could limit the appeal of such an approach in these industries, but this issue deserves more detailed examination.

Another factor promoting relative stability in TFP for these industries is that these industries are relatively mature. While PBR does represent a change in the regulatory regime compared with traditional cost of service regulation, the companies mentioned above have long been subject to private sector ownership and commercial incentives. PBR may represent a less dramatic "regime change" than, say, the switch from public to private ownership. If greater inefficiencies occur under public ownership than under rate of return regulation for privately owned firms, then the switch to stronger regulatory incentives may lead to greater TFP acceleration for once-publicly owned firms. If this is the case, then the historical TFP gains registered by a privatized utility industry may not be representative of the TFP gains that are expected going forward. Various techniques can be used to isolate the expected long-run TFP trend, especially econometric techniques that can "decompose" TFP growth into various components. PEG personnel presented econometric decompositions of TFP growth trends in our work for San Diego Gas and Electric. This issue may also be relevant when implementing productivity-based regulation in Australia and deserves greater attention.

4. Related Regulatory Tools

A basic productivity-based regulatory regime can be modified in various ways. These modifications have various objectives. Some are designed to share the benefits from PBR in other ways. Others are designed to ameliorate business risk. Still others are targeted at achieving complementary regulatory goals (*e.g.* service quality, demand-side management). While a full treatment of this topic goes beyond this submission, below I will briefly describe some other regulatory tools and incentive regulation options that may be integrated into the Gas Access Regime.

Earnings Sharing Mechanisms

Earnings-sharing mechanisms (ESMs), sometimes called "sliding-scale" mechanisms, adjust a company's allowed rates when its rate of return has been in a certain range in 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. One important difference is the share of surplus (and/or deficit) earnings assigned to customers. This may change in different ranges of the ROE. Many plans feature a range (called a deadband) in which rates are insensitive to ROE fluctuations. Immediately beyond the deadband, the customer share is commonly 50%. In some plans, the customer share increases at very high rates of return. In others it falls substantially. Some plans are symmetric in the sense of featuring both 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 incentive regulation. They were used in England as early as 1855 to regulate local gas companies.[19] A plan was adopted in Canada in 1877 to regulate Consumers Gas Company. An early American plan was established in 1905 for the Boston Consolidated Gas Company, and a plan for the Potomac Electric Power Company, approved in 1925, remained in effect until 1955.

ESMs are also used today in the regulation of several U.S. energy utilities. Two of the more long-standing plans with these features are the Rate Stabilization and Equalization (RSE) plans for the base rates of Alabama Power and Alabama Gas. These were approved in 1982 and 1983, respectively, and are still in effect. They adjust base rates whenever earnings are outside of relatively narrow deadbands around the allowed ROEs. The plans have been reviewed and re-approved on several occasions. One important modification took place in 1990, when a benchmark incentive for non-gas operation and maintenance (O&M) costs per customer was added to the plan for Alabama Gas. Both plans include adjustment provisions to allow for automatic recovery of changes in income taxes, and certain local tax rates.

Several ESMs have recently been approved for electric utilities. Examples are the plans for Ameren Union Electric, United Illuminating, Tampa Electric Company, Arizona Public Service, Public Service of Colorado, Mid American Energy, Entergy, Northern States Power, Otter Tail Power, and Black Hills Power and Light. Base rates in all these plans are otherwise frozen for a term of several years.

ESMs are also common in rate and revenue indexing plans of U.S. energy utilities. Of the indexing plans discussed above, all except Pacificorp-California, Central Maine Power-power distribution, and Berkshire Gas contained an ESM. However, the CMP power distribution plan did have a *lower* limit on how far returns could go before the Company could petition for changes to the plan. The Boston Gas plans also have wide deadbands around the allowed ROE within which earnings are not shared with customers.

There are both advantages and disadvantages with using ESMs in rate regulation. One clear disadvantage is that ESMs can weaken incentives for cost cutting and marketing. Utility managers clearly have less incentive to undertake such efforts if

[19] Trebing, H., "Toward An Incentive System of Regulation", *Public Utilities Fortnightly*, July 18, 1963, p. 22-37.

doing so leads in part to price reductions. A continued focus on earnings also maintains the potency of inherently controversial issues like utility-affiliate transactions and cost allocations between core and non-core services. Regulatory attention to these issues can both discourage profitable diversification and impose regulatory costs through ongoing monitoring and evaluation.

Not withstanding these problems, earnings sharing has some important potential benefits. It is a predetermined and automatic means of adjusting prices for a wide range of external developments that could otherwise produce windfall gains and losses for the utility. By mitigating the potential for windfalls, earnings sharing reduce business risk. Their ability to reduce a utility's business risk has been an important rationale for the ESMs that have been included in US PBR plans.

ESMs will also, by design, keep utility earnings within politically acceptable bounds and hence may build consensus among parties. This can increase regulatory commitment and thereby decrease regulatory risk. These benefits can in principle have a positive effect on incentives that more than offsets the negative incentive effects of the sharing itself.

Benchmark Regulation

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 most common type of benchmark regulation mechanism is a service quality incentive (SQI). SQIs have been approved for power distributors in Victoria and South Australia and by the ACCC for several power transmission companies. This type of benchmark plan is a countervailing incentive that encourages utilities to maintain or improve the quality of their services at the same time that they have stronger incentives to cut costs.

Other types of benchmark plans focus on a company's cost performance. Many of these plans are complementary to the basic ratesetting mechanism and do not replace regulatory reviews entirely. For example, some early US incentive regulation plans focused on achieving narrow cost or performance targets, like generator heat rates or plant construction costs. However, other benchmark plans have focused on relatively comprehensive cost or performance targets and reward or penalize the utility accordingly. Perhaps the most prominent of these mechanisms is the Performance Evaluation Plans (PEPs) approved for Mississippi Power. Mississippi Power has been subject to one version or another of PEP since 1986. A brief summary of the history of this plan is included in the Appendix of this submission.

Risk Mitigation

As noted, one of the potential benefits of earnings sharing mechanisms is that they can mitigate both business and regulatory risk. Other regulatory tools can also be integrated into a regulatory regime that address risk more directly. Such provisions can be important because "high powered" incentive regimes can also be more risky than more low-powered regulatory approaches.

One such tool was discussed in the previous section. An industry-specific inflation factor is tailored to measure input price trends in the regulated industry. It therefore reduces the risks that there will be sudden changes in unit costs that are not reflected in the (economy-wide) inflation factor or X factor.

Another regulatory tool is the Z factor. The Z-factor adjusts the allowed rate of price escalation for external developments that are not reflected in the inflation and X-factors. One rationale for Z-factor adjustments is to recover the effect on the Company's unit cost of changes in government policy. Absent such adjustments, policymakers can change policies in ways that increase the Company's unit cost confident in the knowledge that earnings rather than rates will be affected. Hence Z-factors can be used to protect utilities from some regulatory risks. Another rationale for Z-factors is to adjust for the effect of external developments on industry unit costs that cannot be captured by the inflation and X-factors.

A more dramatic risk protection device is the offramp. Offramps allow for changes in the terms of price control plans when certain events occur. An example of an offramp is the lower bound on earned ROE in the Central Maine Power-power distribution plan.

Menus

The tools above and others can be combined in various ways. Some economic literature finds that appropriately constructed "menus" of regulatory options can lead to efficient regulatory outcomes. With this approach, alternative price control plans with varying regulatory parameters could be devised. An example might be a menu that presents three different regulatory options, each of which has a different X factor and an associated earnings-sharing mechanism. A higher X factor would be associated with a less demanding ESM, while a lower X factor would have a more demanding ESM. The Company could then select its desired choice from the menu.

While menus may have some theoretical appeal, they must be constructed carefully if they are lead to efficient outcomes. Below I discuss one tool that may be useful in constructing regulatory "menus," as well as evaluating regulatory alternatives more generally.

5. Incentive Power

The "power" of a regulatory regime has been receiving greater attention in recent proceedings. Because this concept is becoming increasingly important, and may in fact be relevant to evaluating regulatory options for the Gas Access Regime, I would like to review the incentive power idea briefly before discussing how it may be applied in the current Review.[20]

Incentive regulation can be viewed as a form of regulation that utilizes both accounting data from the regulated firm and data external to the firm's operations.[21] An incentive regulation regime incorporates both accounting and external data into ratemaking by specifying two components of regulated rates. One is the regulated firm's own unit cost. The second is an award mechanism or incentive contract. This mechanism rewards the utility if it is able to keep its unit cost below an objective measure, $UC^{external}$, and penalizes the utility if its costs rise above that objective standard.

In general, we can specify an award rate, β, that determines the fraction of unit cost performance improvements that are either retained or lost by the utility depending on its performance. The award rate may assume a value between zero and unity. If $\beta = 1$, the utility keeps all the benefits of improving its performance relative to the unit cost standard and is responsible for all unit costs that exceed the benchmark. If $\beta = 0$, the utility keeps none of the benefits and is responsible for none of the losses.

The value of β is sometimes referred to as the "power" of the incentive scheme. Ratemaking under this general incentive regulation approach is characterized by the following relationship:

$$\begin{aligned} P^{utility} &= UC^{utility} + reward \\ &= UC^{utility} + \beta\left(UC^{external} - UC^{utility}\right) \\ &= \beta UC^{external} + (1-\beta)UC^{utility} \end{aligned}$$

It can be seen that the general incentive regulation mechanism sets prices according to a weighted average of the utility's own unit cost and an external unit cost performance measure. If the award rate $\beta = 0$, output prices depend entirely on the utility's own unit cost. If $\beta = 1$, prices depend entirely on a unit cost performance standard that is external to the regulated utility.

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[20] The exposition that follows below was first presented in the 1997 report by myself and Mark Lowry, *op cit*.

[21] The ideas below are similar to those presented in Chapter One of Laffont and Tirole's *A Theory of Incentives in Procurement and Regulation*, op cit. However, our example differs from theirs in that we discuss incentive regulation in terms of prices rather than revenues and specify a slightly different award mechanism.

Each of these outcomes represents one of the two basic forms of regulation. Ratemaking that depends only on the unit cost of the regulated utility ($\beta = 0$) is a form of "pure" cost of service regulation and "low powered" regulatory regime. Conversely, ratemaking based entirely on external performance standards ($\beta = 1$) is a form of "pure" price cap regulation and a "high powered" regulatory regime. Any given regulatory regime will lie between one of these two polar cases. Where a given type of rate regulation lies on the continuum between pure price caps and pure cost of service regulation depends on the relative weights that the regulator places on the utility's own unit cost and external performance standards. As my previous examples show, the application of productivity-based regulation in the US is very high-powered in the sense that external data are used to set the adjustments in a utility's allowed prices, but these regulatory plans also contain other provisions designed to reduce risk and/or share benefits with customers. While achieving these goals is important, doing so also tends to reduce the power of the regime.

There have recently been greater efforts to define and *quantify* the power of specific regulatory regimes. These efforts have been most prominent in the United Kingdom. The National Audit Office report on "Pipes and Wires" industries presented a simple analytical model to quantify and evaluate the incentive power of specific incentive regulation regimes. These steps have been extended in Ofgem's current review of power distribution price controls. In Australia, recent studies by Darryl Biggar for the ACCC highlight the importance of incentive power and present some mathematical criteria that can be used to evaluate regulatory alternatives.

My firm, Pacific Economics Group (PEG), has also been investigating the incentive power issue. We have developed an analytical tool that can quantify the power of incentives and long-run benefits to customers and shareholders under a very wide variety of regulatory alternatives. These include many regulatory plans that are intermediate between the pure price cap and cost-plus models discussed above. Plans can therefore be ranked in terms of the power of the incentives they create and the overall benefits they are expected to generate for different parties.

PEG calls this analytical tool its "incentive power model." Using a sophisticated optimizing algorithm, we model how companies maximize profits subject to different regulatory constraints that are embodied in regulatory plans. Regulatory scenarios are evaluated by varying the parameters of a plan. The incentive power model therefore establishes a type of benchmark that shows the maximum potential benefits to customers and shareholders that are inherent in a given regulatory option *if* the regulated firm responds optimally to the incentives that the plan creates.

For example, PEG's incentive power model quantifies how overall incentives, customer benefits and shareholder benefits are affected by:

- the term of the PBR plan (*e.g.* three years or five years)
- a "symmetric" earnings sharing mechanism that shares both over- and under-earnings at a constant rate between customers and shareholders

- a "progressive" earnings sharing mechanism where shareholders retain an increasing share of earnings as returns increase
- a "regressive" earnings sharing mechanism where shareholders retain a declining share of earnings as returns increase
- different methods of sharing benefits *between* PBR plans, including full cost of service true-ups, partial cost-based true-ups, and externalized price updates

PEG's incentive power model can also assess whether specific initiatives to cut costs will be profitable under different PBR plans. Efficiency-boosting initiatives differ in many ways, including their up-front costs and payback periods. Our results show that, if the PBR plan is not designed appropriately, some initiatives will not be pursued and both shareholders and customers will lose. Determining whether a given initiative will be profitable involves complex tradeoffs between:

- the upfront costs associated with implementing the initiative
- the term of the PBR plan within which returns are retained
- the amount of returns that must be shared within the PBR term

We believe that this incentive power model has stronger microeconomic foundations than other related efforts. PEG's incentive power model is also more flexible and can evaluate the incentive effects and long run benefits associated with a greater range of regulatory options. This last feature may be especially important in regulatory reviews. The incentive power model has the ability to evaluate regulatory proposals rigorously. It can accordingly be helpful in allowing parties to think through the complex interactions that are involved in designing a specific regulatory regime.

In addition, the incentive power model can be used to generate "menus" of regulatory alternatives. This can be done by varying the terms of a "benefit neutral" plan. That is, by taking a given regulatory plan as a baseline and observing the total long run customer benefits expected to be generated by the plan, new regulatory options can be developed by varying regulatory parameters subject to the constraint that these new options generate the same long-run benefits as the baseline plan. Such an approach would give companies the flexibility to select the regulatory option that appeals most to their preferences while ensuring that customers are as well off as under the baseline regulatory scenario.

Further work is needed on this incentive power model. In particular, PEG would like to explore the issues of gaming incentives (under the building block approach) and risk in greater detail. Nevertheless, we believe that this incentive power model responds to both fundamental theoretical concerns and regulatory issues that are "ripe" in Australia and overseas. Further work may make this model an especially valuable tool for evaluating the merits of different regulatory approaches.

6. Regulation and Investment

Before concluding, I will briefly address the issue of regulation and investment. A number of prior submissions to the PC have argued that regulation can have a "chilling effect" on gas infrastructure investment. A principal problem is the "asymmetric truncation" problem, whereby asset owners are penalized with bad returns when they are inefficient but cannot benefit through higher returns when they register good performance. Some submissions seem to go farther and suggest that price regulation *per se* has a chilling effect on investment, particularly "greenfields" projects.

While there is no doubt that bad regulation can deter otherwise efficient investment, it is important not to exaggerate the impact of regulation *per se*. I believe the recent experience from the US suggests that "greenfields" gas developments can take place in a regulated environment. This is demonstrated in both the gas transmission and gas distribution sectors.

Gas Transmission

Gas transmission in the US can certainly be characterized as a mature industry. The first interstate gas pipelines (originally for manufactured "town gas" rather than natural gas) were constructed in the late 19th century. A boom in natural gas pipeline construction began in 1925 and continued into the early 1930s. This boom period was interrupted by the Great Depression and World War II, but it resumed with renewed vigor in the post-war period. The North American gas market also became interconnected internationally in 1957 when separate connections were made to gas pipelines originating in Mexico and Alberta, Canada. By 1984, there was a total of 284,954 miles of gas transmission pipe in the United States (and an additional 750,168 miles of gas distribution main). Most major end-use markets were served by more than one pipeline. The US natural gas industry was heavily regulated during all but the earliest part of this history. Indeed, during some of the periods of greatest infrastructure development (the 1950s and 1960s), the industry was regulated "from wellhead to burner tip," and essentially no natural gas function was unregulated.

The US natural gas industry has undergone substantial deregulation and structural change since 1978. However, gas transmission services are still subject to price regulation, almost invariably using traditional cost of service methods. This ongoing regulation has nevertheless coincided with significant competition for pipeline services, including pipeline-on-pipeline competition and negotiated contracts for a large share of interstate gas volumes. There has also been substantial new investment in gas transmission infrastructure. Data from the US Department of Energy show that the total miles of gas transmission pipe increased from 284,954 in 1984 to 307,524 in 2002, equivalent to an average of 1274 additional miles each year. Significant transmission pipelines that have either been completed recently or are under construction include the Alliance Pipeline, a $2.5 billion, 1875 mile pipeline from western Canada to Chicago, and the Southern Trails Pipeline, a 700 mile pipeline from the Permian basin in northwestern New Mexico to Long Beach, California. It is significant that these regulated projects have been funded to major markets (Chicago and greater Los Angeles, respectively) that are both already served by multiple pipelines.

Gas Distribution in Maine

The geographic area in the continental US that has traditionally had the least developed natural gas industry is northern New England.[22] The reason is the distance of these markets from the Gulf Coast gas basin (in Louisiana and Texas), which provides most of the natural gas to the northeastern US. Gas transportation costs naturally rise as pipelines are extended farther from the Gulf Coast production area into the northeast. These higher transportation costs tend to make natural gas cost prohibitive compared with other fuels, principally petroleum-based home heating oil and residual fuel oil (in industrial applications). These higher transportation costs meant that, in most of the northeastern-most state of Maine, there has historically been little to no use of natural gas.[23]

This situation began to change in the late 1990s and early 2000s. In late 1998, the TransQuebec and Maritimes Pipeline was extended from just east of Montreal, Canada to the New Hampshire border, where it interconnected with the Portland Natural Gas Transmission system. Even more significantly, in 2000 the Maritimes & Northeast (M&NE) Pipeline came on line carrying gas from the Sable Island gas basin. This basin is located offshore from Nova Scotia, Canada, which is just north of Maine. The M&NE Pipeline travels directly through Maine, past the state's largest population centers of Bangor and Portland before it terminates just outside Boston. These pipeline investments meant that much of Maine could be served by nearby and/or cost competitive natural gas supplies for the first time.

This has prompted the establishment of "greenfields" gas distributors in the State. Two new gas distributors have been formed (Bangor Gas and Maine Natural Gas). Their distribution services are regulated in interesting ways. For example, the gas distribution prices for Bangor Gas have been set using a combination of "benchmark" and index-based methods. The initial (2000) distribution rates for the company were not based on either actual or projected costs for the company's gas delivery operations. Rather, these prices were set to be equal to the difference between the retail (delivered) price of heating oil and the company's cost of purchasing gas. Since heating oil is a close substitute for natural gas in Maine, this differential essentially sets distribution rates at a level that just allows natural gas to be competitive in terms of *price* with home heating oil, regardless of what the company's initial *cost* is of providing this service. This may be interpreted as a very strong application of the competitive market paradigm that was discussed above.

[22] There is even less gas use in Hawaii, which has no natural gas supplies, but does have limited distribution of town gas to some areas.

[23] A small gas distributor, Northern Utilities, has provided service to some customers in and near Portland, Maine; this company currently has about 22,000 customers.

Changes in Bangor Gas's distribution prices are set according to a GDP-PI minus X indexing formula. This mechanism will operate for ten years. In the first five years (2000-2005), the X factor was 0. In the last five years (2006-2010), the X factor will be 0.5%. While these values were not chosen on the basis of any TFP study, they are quite close to the values chosen in the Boston Gas indexing plans (0.5% and 0.41%, respectively, in the initial and updated plans). Recall that these TFP studies were explicitly based on a *regional* definition of the gas distribution industry, which would in principle include Maine.

I believe that this gas distribution example is potentially relevant in Australia. This is a clear example of a greenfields gas distribution development. The prospect of regulation *per se* did not deter these greenfields investments. Indeed, investment took place under a form of regulation requested by the company that was explicitly designed to combine high-powered incentives (by separating allowed prices from the company's cost) with a long-term regulatory plan that provided greater certainty for investors. This is evident from the Order approving the Bangor Gas plan, which states "..Bangor Gas has requested a rate plan with a long term within which it may gradually recover the front-end loaded costs of system development. Bangor Gas asserts that it must convince its investors that the revenues it has projected over the term of the plan will remain stable, so the plan seeks to minimize Commission involvement in rates for a 10-year period. In essence, the plan purports to allocate the risk of poor performance, and the potential for high returns, to Bangor Gas."[24] This was the plan the Maine Commission approved, although it should be noted that the company's proposal also contained an ESM that shared earnings above a 15% ROE with customers.

7. Conclusion

In sum, theory and experience both indicate that productivity-based regulation can be a valuable regulatory approach. This option therefore deserves consideration for the Gas Access Regime. A productivity-based regulatory regime can also integrate regulatory tools designed to achieve objectives other than "high powered" incentives, such as reducing business and regulatory risk and sharing benefits with customers. Incentive power models may be important for evaluating the full range of mechanisms that can be brought together when designing a regulatory regime. Such models provide a rigorous method for evaluating which set of regulatory tools is expected to create the greatest long-run benefits for customers and shareholders.

As others who have examined the issue have noted, implementing a productivity-based regulatory regime does involve certain challenges. These challenges include ensuring that robust, consistent historical data are available to calculate industry TFP and input price indexes; evaluating whether differences in utility operating environments (e.g. urban versus rural territories, variations in geographic, network and other characteristics) should be accommodated in price controls; analyzing

[24] Maine Public Utilities Commission, Order Approving Rate Plan Docket No. 97-795, p. 3.

whether there have been transitory TFP changes (*e.g.* one-time efficiency gains related to privatization) that are not representative of long-run TFP trends; and assessing whether PBR is equally applicable for gas distribution and gas distribution companies. These issues are not insoluble but can be readily addressed through research.

Appendix: Mississippi Power PEP Plan

Mississippi Power Company (MPC) has operated under a Performance Evaluation Plan (PEP) since 1986. PEP-1 was in effect until 1993 and provided for quarterly adjustments of MPC's rates and allowed returns depending on the company's performance in a number of areas. Better performance increased MPC's allowed rate of return, while allowed returns declined when performance deteriorated.
The features of PEP-1 were determined through a collaborative process between MPC, Commission Staff and major intervener groups. The discussions focused on choosing a comprehensive set of performance indicators. To promote comprehensiveness, PEP-1 included several performance variables.
Operationally, PEP-1 was administered through a five-step procedure:

1. MPC's Earned Return on Equity (EROE) was computed.

2. A Benchmark Return on Equity (BROE) was calculated. The BROE was determined as the average of three financial models that are used to calculate expected utility returns.

3. MPC's performance rating was calculated from data on its performance in the targeted areas.

4. The BROE and performance rating were used as inputs to the so-called PEP-1 matrix. This matrix determined the allowed range of returns for MPC. The midpoint of allowed returns was equal to the BROE. Higher performance ratings increased the allowed earnings range by up to 100 basis points above the BROE; lower performance ratings reduced the allowed earnings range by as much as 100 basis points below the BROE.

5. The EROE was compared to the allowed range of returns given by the PEP-1 matrix and required revenue adjustments were made.

Seven performance indicators were specified in PEP-1: customer price, customer satisfaction, service reliability, equivalent availability, construction performance, contribution to load factor, and employee safety. The first three indicators were directly linked to customer welfare. The customer price indicator evaluated the level of MPC's retail prices compared with the retail prices of utilities in the Southeastern Electric Exchange (SEE). The customer satisfaction indicator measured the public's perception of MPC's service. The service reliability index measured the reliability of the MPC's power supply.

The next three indicators were focused on the efficiency of MPC's operations. The equivalent availability indicator measured the availability of generating units to produce electricity. The construction performance indicator measured the correspondence between MPC's budgeted and actual expenditures on construction projects. The contribution to load factor indicator measured the ability of MPC to utilize its capacity.

The final indicator was focused on the welfare of MPC's employees. The employee safety indicator was a measure of the safety of the MPC workplace. Safety was measured by the amount of employee time lost because of accidents.

Each indicator was evaluated against a benchmark level of performance. These benchmarks were determined through negotiation between the parties. A score between 0 and 10 was awarded for each indicator, with higher scores indicative of better performance. In most cases, the value of the indicator was based on MPC's operations over the 12-month period that ended in the last month of the quarter of the evaluation period.[25] Individual performance indicators were then weighted to arrive at a comprehensive performance rating.[26]

MPC was placed into one of five performance categories based on its performance rating. The performance category determined the allowed earnings range for the company. The relationship between performance ratings, performance categories and the allowed earnings ranges (in basis points, bp) was as follows:

Performance Rating Range	Performance Category	Midpoint of Allowed
0.0 - 2.0	I	BROE less 100 bp
2.1 - 4.0	II	BROE less 50 bp
4.1 - 6.0	III	BROE
6.1 - 8.0	IV	BROE plus 50 bp
8.1 - 10.0	V	BROE plus 100 bp

Revenue changes took place based on the relationship between actual MPC earnings and the allowed earnings range. Four types of revenue adjustments could result from this comparison:

1. If EROE was above the allowed range and MPC was in performance categories I, II, III or IV, then revenues would be reduced until returns were at the midpoint of the allowed range.

2. If EROE was above the allowed range and MPC was in performance category V, then revenues would be reduced until returns were halfway between the EROE and the midpoint of the allowed range.

[25] One exception was for the customer service indicator, which was based on the results of a semi-annual survey of customer satisfaction.

[26] The following weights were applied: customer price, 0.2; customer satisfaction, .15; service reliability, .16; equivalent reliability, .16; construction performance, .11; contribution to load factor, .11; safety, .11.

3. If EROE was below the allowed range and MPC was in performance categories II, III IV, or V, then revenues would be increased until returns were at the midpoint of the allowed range.

4. If EROE was below the allowed range and MPC was in performance category I, then revenues would be increased until returns were halfway between the EROE and the midpoint of the allowed range.

From these rules for revenue adjustments, it is clear that PEP-1 could influence MPC's earnings in two ways. First, higher overall performance ratings would tend to increase the allowed range of earnings. In addition, MPC's returns could be outside of the allowed range if the company was in either the highest or lowest performance categories. The last feature removed the upper bound on MPC's potential earnings and therefore accentuated the incentives for efficient performance. Consumers would also benefit from performance gains since rates would be reduced automatically anytime earnings exceeded the allowed range.

The operation of the PEP-1 matrix can perhaps be clarified through numerical examples. Using actual MPC data, in the fourth quarter of 1990 the BROE was calculated to be 12.79%. The company's performance rating was 8.7. From the PEP-1 matrix, this performance rating placed the company in performance category V. When MPC is in this category, the *midpoint* of MPC's allowed earnings is100 basis points above the BROE, so the midpoint of the company's allowed earnings was increased to 13.79%. Since there was a deadband of 100 basis points on either side of the adjusted BROE, earnings between 12.79% and 14.79% did not require revenue adjustments. The company's actual earnings rate (EROE) in the fourth quarter of 1990 was 13.476%. Since this return was within the allowed range, MPC was not compelled to adjust its rates.

In July 1993, several changes were made to the PEP-1 plan. For our purposes, two such changes are noteworthy. First, the amount of sharing would be related to MPC's retail prices relative to those of proximate utilities. Customers would be subject to a greater fraction of revenue adjustments when MPC prices were low relative to those of electric utilities in the southeastern U.S. The opposite would be true if relative MPC prices were high. More precisely, the company proposed that customers' share of rate adjustments be given by the formula:

$$Customer\ Share\ = \frac{(Avg.\ Price\ per\ kWh\ )_{SEE}\ -\ (Avg.\ Price\ per\ kWh\ )_{MPC}}{(Avg.\ Price\ per\ kWh\ )_{SEE}\ -\ (Avg.\ Price\ per\ kWh\ )_{LowCost}}$$

Here, the subscripts SEE, MPC and LowCost refer to the Southeastern Electric Exchange, Mississippi Power Company and the lowest cost SEE Utility, respectively. Based on the actual price data for these groups in June 1993, the customer share would have been equal to .785. Therefore, if actual earnings were less than the lower end of the Range of No Change, revenues would be increased by 78.5% of the difference between EROE and the bottom of this range. Alternatively, if a rate reduction were required, revenues would be reduced by 21.5% of the difference between EROE and the top of the Range of No Change. This application would incent MPC to reduce its prices relative to those of other utilities in the region. In fact, if MPC had the lowest prices in the SEE, it would be able to retain 100% of earnings outside of the allowed range and could fully recover earnings below the allowed range through revenue increases.

Another change was that the number of performance indicators was reduced. The plan eliminated the construction performance, contribution to load factor and employee safety measures. The Commission found that the four remaining indicators more closely reflected the concerns of customers. These indicators were re-weighted so that the customer price indicator now contributed 40% to the performance rating. Customer service, service reliability and equivalent availability would receive weights of 20% each.

These and a few other administrative changes were approved to the plan, and the modified plan was called PEP-2. The Mississippi Commission approved this plan in October 1993. It has been in effect to the present day, although there have been a few additional modifications. For example, the number of indicators was reduced (the generation availability indicator was eliminated) so that now there are only three indicators. However, the basic structure is the same, and the plan now goes by the name PEP 2A. The third generation of this plan was approved in 2001.