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Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues

Volume I

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Acronyms and Abbreviations

ACMI	Average customer minutes of interruption
ARP	Alternative Rate Plan
ARPC	Average revenue per customer
BLS	U.S. Bureau of Labor Statistics
CAIDI	Customer Average Interruption Duration Index
CMP	Central Maine Power
ConEd	Consolidated Edison of New York
COS/ROR	Cost of Service/Rate of Return
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPI-U	Consumer Price Index, Urban Consumers
DIRAM	DSM Incentive and Revenue Adjustment Mechanism
DSM	Demand-side management
ECI	External cost index
EIA	Energy Information Administration, U.S. Department of Energy
ERAM	Electric revenue adjustment mechanism
FAC	Fuel adjustment clause
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GNP-PI	Gross National Product-Price Index
GPNA	Gross plant net additions
IRP	Integrated resource planning
LEC	Local exchange companies
MERIT	Measured Equity Return Incentive Term (NMPC)
NERAM	Niagara Electric Revenue Adjustment Mechanism
NMPC	Niagara Mohawk Power Co.
NRS	Net resource savings
NYDPS	New York Dept. of Public Service (Staff of the NYPSC)
NYPSC	New York Public Service Commission
O&M	Operations and maintenance
PBR	Performance Based Ratemaking
PG&E	Pacific Gas & Electric Co.
PSC	Public Service Commission
PUC	Public Utility Commission
QF	Qualifying facility
ROE	Return on equity
ROR	Rate of return
RPC	Revenue per customer
RSE	Rate Stabilization and Equalization

SAB	System Average Bills
SAIDI	System Average Interruption Duration Index
SARB	System Average Rate/Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric Co.
T&D	Transmission and Distribution
TEP	Tucson Electric Power

Executive Summary

Introduction

The U.S. electric utility industry is undergoing a restructuring where its generation segment is experiencing reduced entry restrictions and a relaxation of price regulation. These industry changes are being driven by changes in technology and policy initiatives on the part of Congress, the FERC, and state regulatory commissions. Competition rather than regulation is seen as the dominant organizing principle in the generation segment. In addition to increased wholesale competition, competition is increasing on the retail side of the electric industry. Self generation and energy efficiency have put pressures on utilities and now there is pressure in some states to allow retail wheeling. The outcome of these increased competitive pressures is uncertain but they are causing regulators and utilities to call for the reform of regulation on remaining monopoly functions, which includes transmission, distribution, and supply to captive customers. Current regulation, which is typically a form of *cost-of-service, rate-of-return* (COS/ROR) regulation, does not reward utilities for exemplary performance and can be complex and costly to conduct for a utility that provides a mix of monopoly and competitive services.

In place of COS/ROR, regulators and utilities are examining *performance-based ratemaking* (PBR) of monopoly utility services. PBR strengthens a utility's financial incentives to lower rates or costs relative to traditional regulation. PBR weakens the link between a utility's regulated prices and its costs. This decoupling is accomplished by decreasing the frequency of rate cases, employing external measures of cost for the purpose of setting rates, or a combination of the two. In the United Kingdom in recent years, incentive regulation has been adopted for various types of public utilities, including electricity and natural gas distribution companies, water companies, and airports. In the U.S., comprehensive incentive regulation has made greatest inroads in the telecommunications industry. For electric utilities, most rate incentives have been limited to ones that target fuel purchases or the performance of individual power plants. In this study, we focus on a newer breed of incentive regulation which comprehensively regulates an electric utility's rates or revenues.

Historically, COS/ROR regulation has been criticized for its focus on rate of return which causes a distortion in a utility's use of capital and labor and can cause inefficient behavior. This distortion is commonly known as the Averch-Johnson (A-J) effect. Poor rewards for incremental managerial effort also result in resource inefficiencies. PBR has long been of interest because it provides incentives similar to those of the competitive marketplace. PBR can provide utilities with a greater incentive to make productivity-improving actions, and greater ability to price flexibly and reduce regulatory costs. Also it is generally recognized that the allocation of utility common costs under COS/ROR becomes more complicated as the number of competitive services increases; PBR benchmarks, which do not rely on the allocation of common costs, simplify the process of setting rates for the remaining monopoly services. Finally, the ongoing restructuring has not only increased the portion of the industry that is competitive but has increased the uncertainty regarding the boundary between a utility's monopoly and competitive portions. Even though a utility is a monopolist for some services today, it may face deregulation and competition in the future; thus, the importance of efficient performance is heightened. Because of this, many see PBR as a bridge between COS/ROR regulation and deregulation.

Approach

Our objective is to review in detail electric utilities' current experience with PBR. The report should be of interest to technical staff of utilities and regulatory commissions that are actively considering or designing PBR mechanisms. To meet our objective, we define the types of comprehensive PBR being considered by electric utilities and review 11 implemented or proposed PBR plans. We summarize each plan, provide a comparative analysis of features, and identify emerging trends. We focus on the PBR plans as filed by utilities or as adopted by regulatory commissions. Ultimately it will be desirable to analyze the performance (results) of PBR mechanisms, but at this time insufficient data exists for us to conduct such an analysis.

PBR plans require specification of key elements and we discuss several including term, commitment, indexing methods, and earnings sharing mechanisms. We also discuss the coordination of multiple, separate incentive mechanisms. Finally, we look at the interaction among PBR and utility-sponsored energy efficiency programs and the restructuring of the industry's generation segment.

Types of PBR

We simplify the vast body of knowledge on incentive regulation and categorize our sample of 11 plans into three types of incentive regulation for electric utilities: sliding scale, price cap, and revenue cap.

Sliding Scale

Under sliding scale regulation, prices are adjusted to keep a utility's rate of return within or close to a rate of return band. If earnings become too large, rates are cut, and, if earnings become too small, rates are increased. The primary rationale for sliding scale regulation is to reduce the frequency of rate cases and thus increase regulatory lag. Unfortunately, many of the distortions created by pure COS/ROR regulation can also appear with sliding scale regulation. If the rate of return band (deadband) is narrow and the rate adjustments are made regularly, then a utility may have even less incentive to be efficient than it would under COS/ROR regulation with regulatory lag.

Today, sliding scale regulation most often appears as a mechanism that supplements a price or revenue cap. Used in this way it is called an *earnings sharing mechanism*. A vigorous debate exists over whether earnings sharing mechanisms increase or decrease the overall benefits of PBR.

Price Caps

Under price caps, prices for monopoly utility services are set for long periods of time without regard to the utility's costs. Rate freezes or significant regulatory lag, both forms of COS/ROR regulation, may be viewed as forms of price caps. Price caps are often indexed over time using the formula commonly known as the "consumer price index (CPI) minus X" formula. This formula sets prices each year as a function of the previous year's prices, inflation (I) and a productivity offset (X). CPI minus X has been widely applied as an incentive regulation formula in the U.S. and UK telecommunications industries.

Revenue Caps

Under revenue cap regulation, a regulator caps a utility's allowed revenues with an external index. Subject to this cap, the utility is permitted to maximize its profit margin, presumably by minimizing total costs. Most revenue caps are applied to revenues deriving from base rates only. Although base-rate revenues are generally considered fixed with respect to the level of per-customer sales, revenue caps usually allow some adjustment for increases in the number of customers. One variation of the revenue cap allows revenues to increase in direct proportion to the number of customers. Revenue caps are usually combined with earning sharing mechanisms to guard against the possible failure of the index to keep returns within acceptable bounds. Although revenue and price caps create the same incentives to minimize costs, they differ significantly in terms of the incentives that they provide for incremental sales. The incentive to maximize sales that exists under price caps does not exist with revenue caps; thus, revenue caps may be considered more "DSM friendly."

Review of Electric Utility PBR Plans

Our sample of 11 plans includes a majority of all U.S. PBR plans that (1) have been implemented or proposed by U.S. electric utilities and (2) are comprehensive in scope. Seven—PacifiCorp, Central Maine Power (CMP), San Diego Gas & Electric Co. (SDG&E), Consolidated Edison of NY (ConEd), New York State Electric & Gas (NYSEG), Mississippi Power, and Alabama Power—of the 11 plans have been implemented, and the rest are still in the proposal stage (Table ES-1).

Table ES-1. Sample of Electric Utility Performance-Based Regulation Plans

	Company	Plan Type	Term† (years) w/ PBR	Term† (years) w/o PBR
1.	Central Maine Power Co. (CMP)	Price Cap	5	3‡
2.	NY State Electric & Gas (NYSEG)	Price Cap	3	3‡
3.	Niagara Mohawk Power Co. (NMPC)	Price Cap	5	3‡
4.	PacifiCorp	Price Cap	3	3
5.	Tucson Electric Power (TEP)	Price Cap (freeze)	5	n.k.
6.	Consolidated Edison of New York (ConEd)	Revenue per-Customer Cap	3	3‡
7.	Pacific Gas & Electric Co. (PG&E)	Base-Rate Revenue Cap	6	3
8.	San Diego Gas & Electric Co (SDG&E)	Base-Rate Revenue Cap & Modified Price Cap	5 2	3 1
9.	Southern California Edison (SCE)	T&D Revenue Cap & Modified Price Cap	6 8	3 1
10.	Alabama Power	Sliding Scale	Indef.	n.k.
11.	Mississippi Power	Modified Sliding Scale	Indef.	n.k.

Notes: † Terms include the litigated base year plus the number of years subject to indexing.
‡ Estimate
n.k. = Not known

We examine such areas as regulatory lag or minimum term (length of time utility agrees to stay out of rate case), the aggressiveness of the indexing method, the existence and type of earnings sharing mechanism, incentives for utility demand-side management (DSM), and overall incentive power. Our major findings are summarized below.

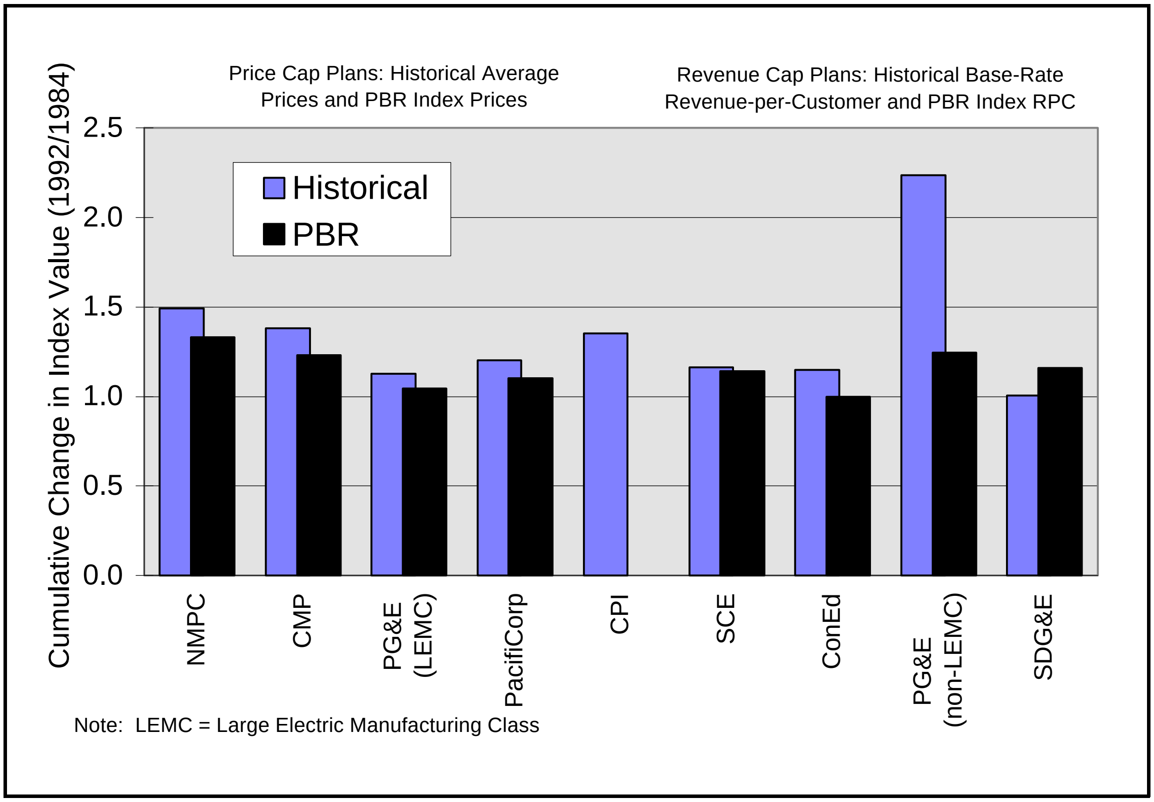
Regulatory Lag Increases Under PBR

One of the simplest and most powerful ways that PBR can increase incentives for improved productivity is to increase the minimum time between rate cases, unleashing the forces of regulatory lag. We compare the frequency of rate cases in the sample of utilities with and without PBR. PBR provides a modest increase: the median time between rate cases (term) in our sample of utilities increased from three to five years (Table ES-1).

Most PBR Plans Use Indices that Provide Ratepayer Benefits

To keep a utility out of rate cases and to provide ratepayer benefits, PBR plans often rely on external indexing of rates or revenues. Most indices use an inflation index and adjust it for expected productivity. Inflation indices and productivity offsets should be evaluated jointly because their combined effect determines overall performance. We analyzed PBR index performance by examining how the price and revenue cap indices would have performed over an eight-year historical period (Figure ES-1). Index values in the terminal year (1992) are divided by the index values in the base year (1984). Index values are compared to historical rate or revenue-per-customer performance and to the performance of the CPI over the same period. It appears that the PBR plans result in improved rates or revenues per customer as compared to utilities' historical performance and to the CPI. Most of the plans easily beat the CPI because most plans use indices that grow at inflation minus a productivity offset. Productivity offsets are in the range of 0.2 to 1.4 percent per year. Although these offsets result in real decreases in prices or revenues, they are modest compared to the productivity offsets adopted in telecommunications incentive regulation, which are often in the range of three to five percent per year. Only SDG&E's revenue cap mechanism appears to allow for greater growth in its index value (revenues-per-customer) than allowed by its historical performance. SDG&E's poor relative performance is a function of a generous allowance for electrical network distribution additions and the fact that its historical performance was quite good.

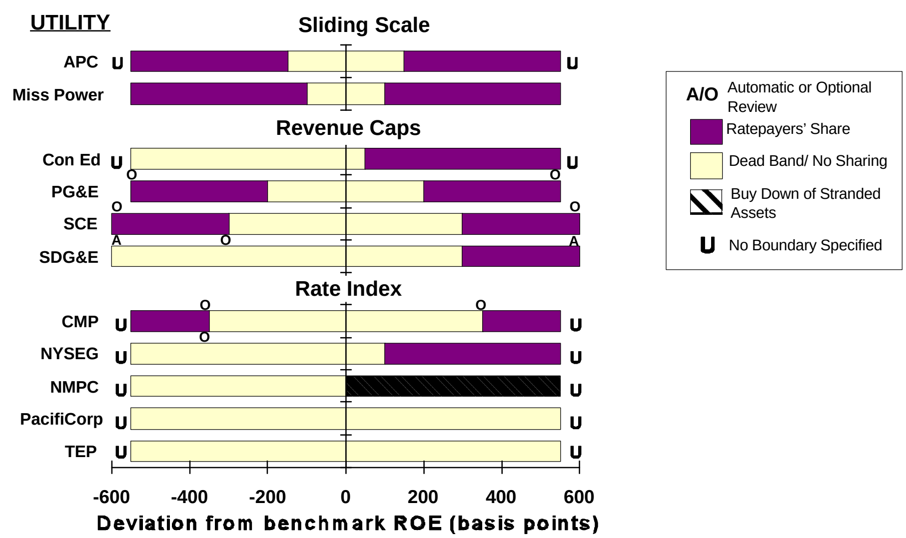
Figure ES-1. Comparison of Historical Values to PBR Index Values: 1984-1992



Earnings Sharing Mechanisms Put Most Utilities at Risk for Returns Around Their Benchmarks

Earnings sharing mechanisms track actual earnings, sharing with ratepayers any earnings that fall below or above certain thresholds. They may be the defining aspect of a PBR plan, as in the case of Mississippi or Alabama's sliding scale mechanisms, or they may supplement a price or revenue cap plan. Earnings sharing mechanisms and earnings limits represent a departure from COS/ROR ratemaking, which usually provides that utilities retain all deviations in earnings between rate cases. All of the earnings sharing mechanisms except NMPC's have "deadbands" where shareholders are at risk for all or most earnings variations. In Figure ES-2, the light solid color indicates that shareholders keep 75 percent or more of any earnings deviations; such a region of high shareholder risk is a deadband. A dark solid color in Figure ES-2 indicates that ratepayers keep more than 25 percent of any earnings deviations. Also shown in the figure are the levels of earnings that trigger an automatic or optional suspension or review of the PBR plan (indicated by "A" and "O").

Figure ES-2. Comparison of PBR Earnings Sharing Mechanisms



Note: Miss Power, SCE, & SDG&E: Power mechanisms are specified in rate of return and have been converted to return on equity (ROE) assuming a debt-to-equity ratio = 1.0.

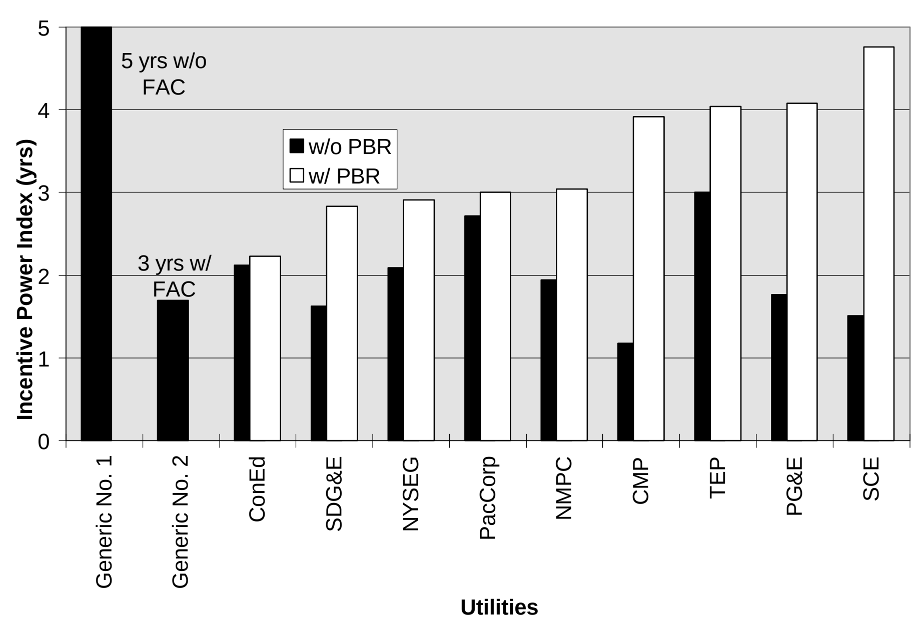
Deadbands follow standard economic theory that says that a utility should keep most or all of the savings created by any incremental investments. Sharing should only occur to mitigate extraordinarily high or low earnings.

Disagreement exists, however, on the design of earnings sharing mechanisms. Some parties, often consumer representatives, argue that utilities should share a high fraction of earnings deviations. NMPC's earnings sharing mechanism is in the spirit of this consumer-oriented model. NMPC proposes to keep only 50 percent of earnings above the benchmark; the rest go toward buying down "regulatory assets." Because these assets are potentially strandable, they may ultimately turn out to be a liability to ratepayers. Thus, NMPC's mechanism, by using above-benchmark returns to reduce these assets (hatch-marked pattern in Figure ES-2), is a form of customer sharing.

Most PBR Plans Strengthen Incentives for Efficiency Compared to Situation Before PBR

We assess the overall incentive power of each electric utility PBR plan by developing our own benchmark, which we call the LBNL Incentive Power Index. The Incentive Power Index indicates the degree to which a utility is at risk for its profits. The LBNL Incentive Power Index is a function of a utility's commitment to stay out of rate cases (in years) and the degree of earning sharing that occurs around benchmark returns. Thus, a utility may score high on the index for having long PBR term, having no earnings sharing mechanism, or having an earnings sharing mechanism with a wide deadband. We compare each utility to itself (without PBR) and to two "generic" utilities: (1) one with no fuel adjustment clause (FAC) and rate cases every five years; and (2) one with base rate cases every three years and a full FAC. We chose these generic utilities to be representative of the typical range of regulatory lag that exists under U.S. COS/ROR regulation. Overall, we find that most PBR plans in our sample represent an improvement over the utility's status quo and represent an improvement compared to Generic Utility No. 2 (see Figure ES-3). Few utilities have index scores that come close to Generic Utility No. 1's score, however.

Figure ES-3. LBNL Index of Incentive Power



The highest-powered plan that has been implemented is CMP's. Its high score comes from a wide sharing deadband, its comprehensive scope, and its term of five years. On a relative basis, CMP, PG&E, and SCE's plans show the highest increase relative to the status quo. Two plans show little improvement in comparison to the "without-PBR" case: ConEd's and PacifiCorp's.

One criticism of PBR is that it is a complicated way of doing something that PUCs have been good at for a long time: setting rates and leaving them fixed for extended periods of time. The LBNL power index clearly shows that there is some truth to this. Generic Utility No. 1 beats all the PBR plans, even ones that include commitments of six to eight years. Before criticizing the incentive power of a PBR plan, however, one should consider the regulatory status quo and ask whether the PBR proposal is an improvement. If it is, then one should consider whether COS/ROR with increased regulatory lag, such as that illustrated by Generic Utility No. 1, would be better. PBR, by generally relying on external benchmarks, can be more responsive to changing conditions than COS/ROR with regulatory lag. In particular, it may be better at responding to external changes in fuel prices than would Generic Utility No. 1, which has no FAC. PBR does, however, add complexity to the regulatory process.

PBR: Implications for DSM

A well-known obstacle for utilities and regulators interested in promoting energy efficiency services is the disincentive created by the net lost revenues from reduced sales. In recent years, regulators have used financial incentives to encourage utilities to pursue cost-effective customer energy efficiency or demand side management (DSM). We examine how DSM incentives are affected by PBR plans, starting by asking whether a utility's PBR plan includes DSM program costs in its revenue or price index. Four of the nine price or revenue cap plans specifically exclude DSM budgets from the *indexed* portion of the PBR. This approach favors DSM because DSM budgets that *are* included in the PBR index will be subject to greater cost-cutting incentives.

We also examine how the PBR plans treat net lost revenues from DSM programs. Price caps put the utility at risk for all net lost revenues, including net lost revenues from DSM programs. It is possible to add net lost revenues created by DSM programs back into the revenue requirement, but, in general, the utility is at risk for sales deviations. In contrast, revenue caps automatically protect shareholders from revenue fluctuations resulting from sales variations because prices are adjusted every year for the latest sales forecast. Thus, the four revenue caps may be considered to be either complete or near-complete sales decoupling mechanisms. Table ES-2 also shows that six of the 11 plans retain incentives that target DSM performance. Incentives for DSM performance are especially important if the plan is a price cap plan because price caps do not allow for recovery of a DSM program's net lost revenues. Only two price cap plans, CMP and TEP, retain shareholder incentives; the other three plans eliminate them.

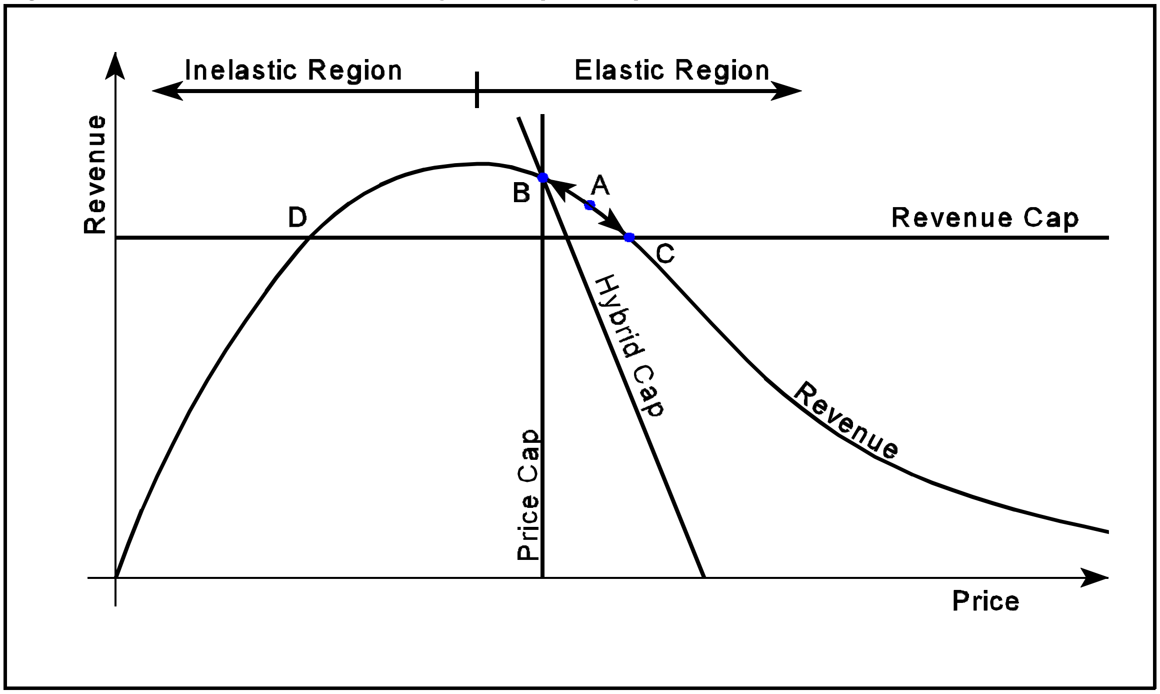
Table ES-2. Treatment of Utility DSM in PBR Plans

Utility by type of PBR	DSM program costs in index mechanism?	Recovery of Lost Revenues	Supplemental Targeted Incentive for DSM
I. Price Cap Plans			
CMP	No	No	Shareholder Incentives (SI) retained
NMPC	Yes	Yes, NERAM (decoupling mechanism) eliminated, but DSM related-lost revenue adjustment added	SI eliminated
NYSEG	Yes	No (previous mechanism eliminated)	SI eliminated
PacifiCorp	Yes	ERAM eliminated	SI eliminated; performance targets adopted
TEP	Yes	No	SI retained
II. Revenue Cap Plans			
ConEd	No	Yes	SI retained
PG&E	No	Yes (ERAM retained for all customers classes except Large Electric Manufacturing Customer Class)	SI retained
SCE	Partially (underspent budget held over or refunded to customers)	Yes (ERAM retained)	SI retained
SDG&E	No (special adjustment mechanism insulates DSM from rate incentives)	Yes (ERAM retained)	SI retained

Note: ERAM = Electric Revenue Adjustment Mechanism
NERAM = Niagara Mohawk Electric Revenue Adjustment Mechanism

In addition to our review of the way our sample of PBR plans treat DSM, we conducted a conceptual analysis of regulatory incentives for DSM created by price and revenue caps. Although it is clear that revenue and price caps provide the same cost minimization incentives, revenue caps remove the disincentive to pursue energy efficiency programs. Unfortunately, revenue caps create troublesome pricing incentives. We confirm a result,

Figure ES-4. Price, Revenue, and Hybrid Caps Compared



recently published in the academic literature, that revenue caps give utilities a strong incentive to act like monopolists. If a utility is held only to a revenue cap, it has an incentive to raise prices, reduce output, and enjoy maximum profit. Figure ES-4 illustrates the problem. A utility confronts a revenue curve that increases with price for low prices and decreases with price at sufficiently high prices. At regulated tariffs, it is a reasonable assumption that marginal demand may be elastic; that is, a one percent change in price causes a one percent or greater change in demand. In Figure ES-4, the region where demand is elastic is to the right of the top of the revenue "hill" and we assume for the purposes of this illustration that the utility begins at point A. Under a revenue cap or revenue-per-customer cap, a utility will benefit from raising rather than lowering prices as a way to meet the requirements of the cap. This is shown as the arc A➔C. The price associated with point C is worse for customers than the price that could occur under a price cap (below point B) or the alternative, but less desirable (to the utility), revenue-cap price (below point D).

As a practical matter, any utility subject to a revenue cap would probably find it difficult to significantly raise prices under a revenue cap, but the incentive to misprice electricity under a revenue cap is a serious concern. Rather than advocate price caps for monopoly services, however, we propose a hybrid price and revenue cap. In Figure ES-4, the hybrid cap is shown as a diagonal line and, in this example, is designed to produce the same price (point B) as a price cap. The hybrid cap does this, however, without the same disincentive for DSM that would be produced by a pure price cap.

Although we developed our hybrid cap based on theory, we have found that it is, in effect, practiced by several utilities that propose or are subject to revenue cap regulation. SDG&E's and SCE's plans both call for price incentives that supplement the primary revenue cap incentive. We believe that this combination of a price and revenue cap could provide the best balance between promoting energy efficiency while making sure the utility chooses prices that are consistent with ratepayer interests.

PBR and Generation-Resource Planning

Planning for new electric generation resources and its substitutes (i.e., DSM) is important but its future is uncertain given ongoing industry restructuring which could reduce the scope of resources under control by the utility. We consider the appropriate type of regulation of electric generation under two distinct levels of competition. Generation can be regulated using COS/ROR (supplemented with integrated resource planning proceedings), regulated using PBR, or deregulated altogether. In terms of the level of competition, the major alternatives are either wholesale competition or wholesale and retail competition (which we call retail competition for short).

Table ES-3. Appropriate Methods of Regulation Under Two Degrees of Competition

Regulatory Approach	Appropriateness of Regulatory Approaches for Each Degree of Competition: Wholesale	Appropriateness of Regulatory Approaches for Each Degree of Competition: Wholesale and Retail
A. COS/ROR regulation combined with traditional IRP	LOW for fuel and purchased power MEDIUM for new resources	LOW, information costs are high, and ability to second-guess the market is low
B. PBR	MEDIUM-HIGH depends on term of resource commitments, availability of appropriate benchmarks	HIGH during transition to competition LOW after generation market is competitive
C. Price Deregulation		MEDIUM during transition to competition HIGH once utility market power is mitigated

Whether PBR is appropriate for the generation segment of the industry depends greatly on the competitive model chosen (Table ES-3). Although COS/ROR is being challenged by PBR, we find that COS/ROR may still be appropriate if a utility builds or makes long-term commitments to new resources. This is most likely to continue under wholesale competition.

Despite its drawbacks, COS/ROR when combined with IRP has some advantages when a utility is in the business of making long-term resource commitments. COS/ROR can provide adequate incentives for capital formation and is less susceptible to having the utility game the timing of the introduction of new long-term resource commitments. PBR, however, clearly has strengths over COS/ROR for the regulation of fuel and short-term purchased power. Further, it is likely that the required length of commitment by utilities for resources will decrease in the future; thus, PBR may eventually be adequate for regulating the entire generation segment.

If one favors retail competition as the ultimate competitive model, then deregulation of utility generation prices is ultimately appropriate. As a practical matter, however, it is unlikely that any state adopting retail competition rules will realize a competitive market overnight. Thus some sort of regulation of a utility's generation portfolio is appropriate during the transition. PBR price cap regulation appears well-suited for this transition.

Concluding Thoughts

Our analysis indicates that it is an open question whether PBR as proposed and implemented by our sample of early-adopting electric utilities represents an improvement over COS/ROR regulation. The PBR plans in our sample are hampered by the relatively short time commitments that are made between utilities and regulators. Further, because of earnings sharing mechanisms and other exclusions, the incentive power of many PBR plans is diluted. The combined effect of modest terms and low incentive power results in some PBRs with incentive powers that differ little from COS/ROR already prevalent in the U.S.

Despite the mixed results of our analysis of PBR plans, however, we believe that PBR still holds promise as an appropriate regulatory framework, especially in light of the ongoing industry restructuring and increased competition. Regulators and utilities that are considering PBR in the future will hopefully benefit from our analysis of key design and policy issues in these first-generation PBR plans.

Introduction: Overview of PBR

1.1 Overview

Performance-Based Ratemaking (PBR)[1] is a form of utility regulation that strengthens the financial incentives to lower rates, lower costs, or improve nonprice performance relative to traditional regulation, which we call *cost-of-service, rate-of-return* (COS/ROR) regulation. Although the electric utility industry has considerable experience with incentive mechanisms that target specific areas of performance, implementation of mechanisms that cover a comprehensive set of utility costs or services is relatively rare. In recent years, interest in PBR has increased as a result of growing dissatisfaction with COS/ROR and as a result of economic and technological trends that are leading to more competition in certain segments of the electricity industry. In addition, incentive regulation has been used with some success in other public utility industries, most notably telecommunications in the U.S. and telecommunications, energy, and water in the United Kingdom.

In this report, we analyze comprehensive PBR mechanisms for electric utilities in four ways: (1) we describe different types of PBR mechanisms, (2) we review a sample of actual PBR plans, (3) we consider the interaction of PBR and utility-funded energy efficiency programs, and (4) we examine how PBR interacts with electric utility resource planning and industry restructuring. The report should be of interest to technical staff of utilities and regulatory commissions that are actively considering or designing PBR mechanisms.[2] Our analysis is organized as follows. In Chapter 2, we provide a framework or typology of "real-world" PBR mechanisms and identify the key economic issues that arise in the design of a PBR plan. In Chapter 3, we review in detail 11 comprehensive PBR plans that have been adopted or proposed by U.S. electric utilities. Our sample size is necessarily small because the total population of PBR plans is limited. Definitive conclusions cannot be drawn in many cases, but we believe our systematic comparison of these early PBR plans provides valuable insights for regulators and utilities that are considering such PBR plans. In Chapter 4, we examine revenue and price cap regulation and consider which one is more compatible with utility energy efficiency programs. In addition to analyzing the compatibility of revenue and price caps with electric utility energy efficiency programs, we compare the pricing or allocative efficiency of these caps; we find that revenue caps encourage distorted pricing unless certain precautions are taken or regulators adopt a hybrid mechanism that essentially combines a price cap with a revenue cap. In Chapter 5, we examine the interaction among PBR, resource planning, and industry restructuring. Significant changes are occurring in the

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1 Performance-based ratemaking is also called performance-based regulation. We use the former term because it appeared first in the literature.

2 For a less detailed introduction to PBR for electric utilities, see Hill (1995) and EEI (1995).

electricity generation sector; the effects of these changes on the industry's overall structure are unknown. Thus, we identify possible industry structures and suggest the types of regulation that we believe may be most appropriate for each. Chapter 6 summarizes our findings and conclusions.

1.2 Performance-Based Ratemaking (PBR) and Incentive Regulation

The most common strategy used by PBR mechanisms is to weaken the link between a utility's regulated prices and its costs. This decoupling is accomplished by decreasing the frequency of rate cases, employing external measures of cost for the purposes of setting rates, or a combination of the two. PBR mechanisms are developed with recognition of the *information asymmetry* between regulators and regulated utilities. Thus, although very complex regulatory proceedings might improve utility prices,[3] lower costs, and increase customer satisfaction, such proceedings are assumed to be infeasible or excessively expensive. PBR, in contrast, places an emphasis on "light-handed" ratemaking methods that improve performance without excessive regulatory oversight.

Incentive regulation schemes have been proposed since regulated public utilities became major business enterprises in the twentieth century.[4] Academic economists have written extensively of incentive regulation during the past 25 years. PBR, as it is used in this report, refers to a "real-world" subset of incentive regulation. The incentive regulation literature provides fundamental rationales for PBR. Two economists, Laffont and Tirole (1993), present a simple but powerful model of incentive regulation:

$$Revenues = a + b \cdot Costs \tag{1-1}$$

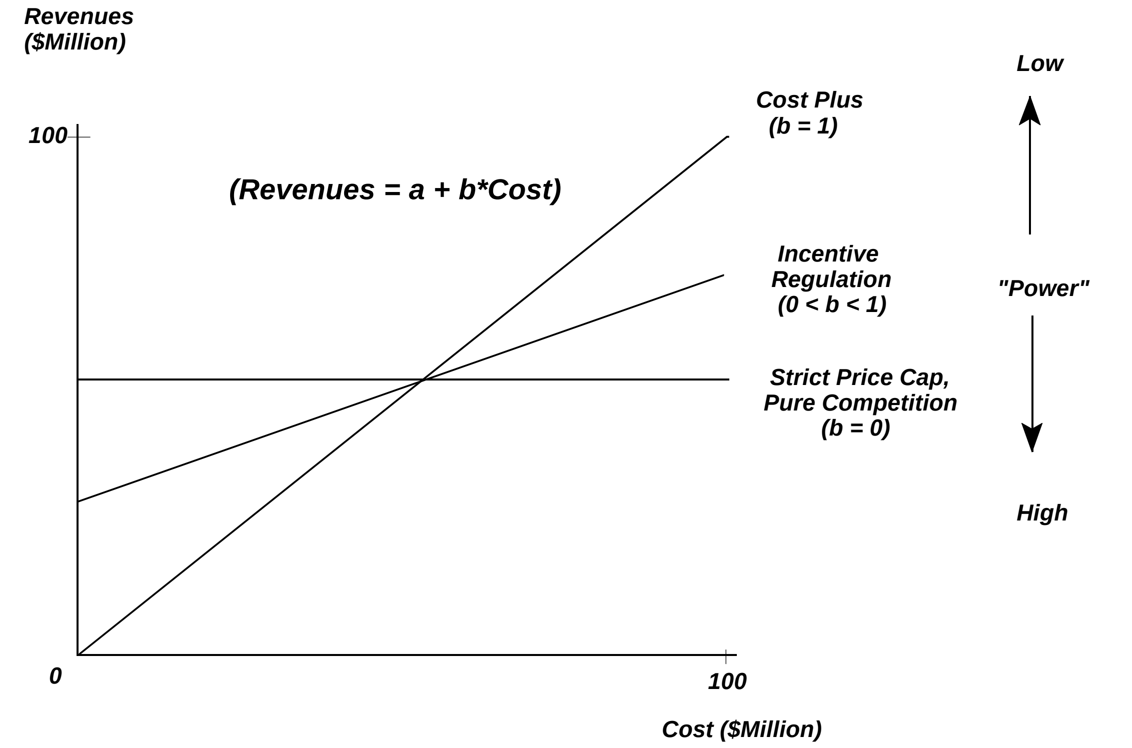
where:

Revenues	=	actual (*ex post*) revenues received
a	=	fixed payment, set *ex ante*
b	=	*ex ante* sharing fraction, 0 < b < 1
Costs	=	*ex post* costs

[3] By *improved* prices, we mean prices that accurately reflect the cost of a utility service delivered in an efficient manner.

[4] Early forms of incentive regulation tended to be of the sliding scale type (defined in Chapter 2). For some early examples of incentive regulation, see Kahn (1971), p. 59.

Figure 1-1. The Impact of Cost Sharing on the Power of an Incentive Regulation Mechanism



Note: b = Sharing Fraction
Adapted from Lyon (1994)

In the view of Laffont and Tirole, regulation becomes "incentivized" when a firm is given a direct financial reward for minimizing production costs for a particular good or service. Equation 1-1 shows a relationship between *ex post* revenues and costs based on two parameters set *ex ante*, a and b. Laffont and Tirole show that a firm's incentive to minimize costs is inversely proportional to the magnitude of the sharing fraction, b. In other words, a firm's risk for cost overruns and its ability to keep any cost savings increase as b decreases. Laffont and Tirole call high-b plans *low-powered* and low-b plans *high-powered* (Figure 1-1). *Incentive power*, which is defined more precisely in Chapter 4 as the change in utility profits resulting from a small change in utility costs or revenues, is a concept used frequently in this report. For each of the three example lines shown in Figure 1-1, the marginal incentive power is constant, equal to (1 - b). As will be seen in Chapters 2 and 3, many PBR plans have different marginal incentive powers for different categories of service or have rates that change as conditions (such as costs or earnings) change.

COS/ROR regulation with frequent rate cases may be thought of as low-powered regulation with a marginal incentive power of zero. Rate freezes, COS/ROR regulation with infrequent rate cases, and price or revenue indexing are forms of medium- to high-powered incentive regulation; they increase the portion of revenues a utility receives via terms set *ex ante* and decrease the portion of utility revenues computed *ex post*. A purely competitive market, where the seller of a product or service cannot influence the market's price, is another situation where incentive powers are high. PBR is often described as a way of making utility regulation mimic some of the incentives that operate in an unregulated competitive market.

High-powered incentive mechanisms are not always preferable to low-powered ones (Lyon 1994) because high-powered mechanisms rely on the regulator's imperfect knowledge of customer demands and utility costs and thus increase uncertainty in utility profits. A high-powered mechanism with no adaptation to *ex post* costs will eventually result in overall prices that are either too high or too low and can threaten the viability of the incentive plan. Thus, designers of incentive regulation must simultaneously balance its short-run incentive power, its overall pricing efficiency, and its ability to remain viable over time. We will consider these three design considerations in more detail in subsequent chapters.

In recent years, incentive regulation has moved from the academic world to the real world of regulation primarily by its adoption in the telecommunications industries in the U.S. and UK (Johnson 1989). Incentive regulation is now widely used for other types of public utilities in the UK, including electricity and natural gas distribution companies, water companies, and airports (CERA 1993; Armstrong et al. 1994). In the U.S. natural gas industry, a handful of gas distribution companies have experimented with incentive regulation (Comnes 1994), and incentive regulation has been proposed but not implemented for natural gas pipelines (FERC 1992; Jaffe 1992). Incentive ratemaking mechanisms for U.S. electric utilities have also been adopted although most mechanisms target performance in the areas of fuel and purchased power costs, and power plant performance (Joskow and Schmalensee 1986; Berg and Jeong 1991). As already noted in this report, we focus on comprehensive rather than targeted mechanisms.

1.3 Cost-of-Service/Rate-of-Return (COS/ROR) Regulation

The value of any regulatory policy initiative may only be assessed by comparing it to its alternative. Existing economic regulation of electric utilities varies by state, but most is COS/ROR regulation in some form. Under COS/ROR, nonfuel rates are based on accounting costs for a test year. In most jurisdictions, test years are still historical, and changes from historical costs are traditionally only allowed for "known and measurable" changes. An allowance for a fair return on capital is included in the cost of service. Nonfuel rates, once set, are typically fixed until the next rate case. Rates cases generally occur irregularly; the average interval between rate cases in the U.S. is between three to five years (Eto et al. 1994). Utilities generally have the right to apply for a rate increase at any time, and public utility commissions and staffs often have the right to initiate rate cases as well. Large capital additions by utilities usually require approval before construction begins, via Certificate of Public Convenience and Necessity (CPCNs) Proceedings. Some CPCN proceedings have their own rules regarding cost recovery.

In marked contrast to nonfuel rates, rates to cover fuel and purchased power expenses for many electric utilities are subject to fuel adjustment clauses (FACs). FACs allow for frequent updating of rates to reflect changes in fuel costs. To avoid litigating test year values, most FACs allow for automatic adjustments in rates subject to after-the-fact reviews of reasonableness. Approximately 39 states and the District of Columbia have fuel adjustment clauses (FACs) for their electric utilities, and approximately 29 states hold hearings on them (Burns et al. 1991). FACs were created beginning during the late 1970s in response to the fuel price fluctuations and supply uncertainties that existed at that time.

The incentive properties of COS/ROR will be discussed further in Chapter 2, but a few incentives are readily apparent and worth noting now. First, COS/ROR uses a utility's own costs as the primary source of information for setting rates. Because of this linkage of rates to costs, COS/ROR is criticized for promoting inefficient behavior and has been labeled "cost-plus" regulation. However, two forces counteract the "cost-plus" nature of COS/ROR. First, utility rate cases can occur infrequently. This delay, known as *regulatory lag*, creates an incentive to minimize costs between rate cases. Second, utilities are no longer pure monopolies in many markets. Competitors threaten to take away market share, and this threat limits inefficient behavior to some degree. If a regulator imposes nondiscriminatory pricing that evens out price differences between customers with and without competitive alternatives, it can be argued that COS/ROR carries the benefits of efficient behavior to all customer classes. Third, imprudent behavior can be checked by the regulator disallowing costs retroactively.

Regulation of utility fuel costs does not possess some of the incentives commonly built into COS/ROR. Regulatory lag is often nonexistent for fuel price regulation because of the prevalence of fuel adjustment clauses (FACs). With FACs, the only incentive to perform is the threat of competition and the desire to avoid disallowances in reasonableness reviews, a risk which is arguably small.

1.4 The Potential Benefits and Pitfalls of PBR

Before going further in defining the specific types of PBR, it is worth laying out PBR's primary rationales. We also summarize the main arguments against PBR. It is too early to say which side is right, but understanding the pro and con arguments will help policymakers conduct their own evaluations, especially in light of the review of existing PBR plans that we present in Chapter 3.

1.4.1 Potential Benefits of PBR

Improved Resource Efficiency

Resource efficiency is the ability of a producer to provide a given quantity of products or services using inputs (e.g., labor, capital, and materials) that minimize total cost. Resource efficiency also includes the ability to make cost-reducing investments (e.g., research, reorganization, and capital equipment) that result in the provision of goods and services at the lowest possible cost over time.[5] Resource efficiency is traditionally measured in terms of productivity, which is defined as the amount of output produced per unit of inputs. PBR gives a utility a financial stake in improved productivity because, compared to COS/ROR regulation, the utility gets a greater share of any resulting cost savings. To the extent that COS/ROR regulation is "cost plus" in nature, it limits the upside and downside returns of the electric utility. Cost-plus regulation gives the utility few incentives to make appropriate investments. Cost savings opportunities may be forgone or, worse yet, investments may be made that provide negative net benefits.

Reduced Administrative and Regulatory Costs

PBR can reduce the cost of regulation. Although this reduction is a manifestation of the resource efficiency benefit already described, it is usually singled out as a separate rationale because the cost savings accrue not only to the utility but also to the regulatory commission and intervenors. The initial proceeding that determines and implements the incentive mechanism can be costly to all involved, but regulatory costs can be decreased if the frequency or complexity of future rate cases is reduced. PBR's ability to reduce regulatory costs may be seen as a result of PBR's recognition of the informational asymmetry between the regulator and the utility. Under traditional COS/ROR regulation, regulators expend considerable effort and expense to bridge the information gap. In contrast, PBR does not try to rectify the information gap, but, instead, relies on the concept of *incentive compatibility*. Incentive compatibility may be thought of as a necessary condition for effective PBR. An incentive compatible PBR plan should elicit the greatest expected performance from a firm even though the regulator does not know (or does not expend large amounts of effort to try to know) what the firm's true costs are. With PBR, the regulator need only know the range of possible costs; from this range, the regulator can develop PBR plans that elicit maximum efficiency from the firm.

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[5] These two types of resource efficiency are sometimes called "static" and "dynamic" efficiency, respectively (PG&E, 1994), or technical efficiency (Pearce 1983). Crew and Kleindorfer (1986) discuss resource efficiency using the terms *X-efficiency, dynamic efficiency, and scale efficiency.*

Improved Allocative Efficiency

Allocative efficiency is achieved when an economy adjusts output to maximize total value (Scherer and Ross 1990).[6] Allocative efficiency is achieved or improved when prices for goods and services are set at marginal cost or, in the case of public utilities, as close to marginal cost as possible, subject to a revenue-requirement constraint. Although it is possible to move to marginal cost pricing under COS/ROR, PBR can make this move if a utility is given pricing flexibility in conjunction with safeguards against excess profits.[7] PBR combined with pricing flexibility can improve utilization of existing assets or capacity holdings because it allows a utility to retain customers with more elastic demands. Major stumbling blocks to pricing flexibility—*i.e.*, whether such flexibility will allow a utility to earn monopoly profits and whether such flexibility will harm captive customers—are overcome when pricing flexibility is proposed in conjunction with PBR. Under PBR, the ratemaking index formula along with any earnings sharing mechanism provide protection against monopoly profits. Also, any revenue shortfall from special contracts is not automatically allocated to captive customers, which gives captive customers additional protection.

Easier Introduction of New Services

Just as PBR combined with pricing flexibility can reduce the complexity of allocating revenue shortfalls, PBR can avoid the complexities created when utilities offer nonmonopoly services. PBR reduces the need to examine the allocation of utility common costs to a new service because the allocation of common costs to monopoly services is implicitly set by the PBR mechanism. Customers are protected from being the "deep pocket" for new utility ventures, and, conversely, shareholders see reduced regulatory risk from having profits "expropriated" by the regulator.

Compatibility with Transition to Competition

One of the most compelling arguments for PBR is its ability to change the mind set of a utility and make it act more like a competitive than a regulated firm. In fact, PBR is almost always proposed by utilities when there is a perceived threat of growing competition. At first, the association of PBR with competition is counterintuitive. For monopoly services, COS/ROR regulation with regulatory lag would seem sufficient, considering the effort that

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6 Pearce (1983) defines allocative efficiency to include both technical efficiency and efficiency created by optimal output. We stick to Scherer and Ross's definition, which includes only efficiency related to optimal output.

7 Improved relative prices are discussed further in Chapter 4.

would be required to unbundle competitive services from monopoly ones. However, as noted in the allocative efficiency and new services rationales, competition and restructuring often increase the complexity of allocating utility facility costs common to both competitive and noncompetitive services. Thus, sticking to COS/ROR ratemaking in such an environment perpetuates incentives for resource inefficiency and increases the cost of regulation. For competitive services, price regulation should end altogether, so, again, PBR seems unnecessary. However, the boundary of what is and is not competitive is blurry and changes over time. PBR is an effective transitional pricing mechanism for industry segments that are becoming more competitive over time. On balance, one may see the association of PBR with competition and restructuring as a way for regulators and the industry to (1) provide captive customers with reasonable rates without resorting to increasingly complex, contentious rate hearings and (2) increase the incentives for improved productivity in light of the possible future deregulation of utility prices.

1.4.2 Potential Pitfalls of PBR

Although the rationales for PBR are strong, they are far from universally accepted. Even supporters of PBR would agree that few of the competing approaches and mechanisms have been adequately tested. Thus, we summarize some of the most commonly cited pitfalls of PBR.

Inability to Commit/Questionable Efficiency Benefits

Much of a PBR mechanism’s incentive power usually comes from its lengthening of the minimum time between rate cases. The longer the time between rate cases, the more benefits from any productivity-improving initiatives are captured by a utility and, thus, the larger the utility’s incentive for such initiatives. Unfortunately, in most states, the ability to commit for the full term of a PBR plan is fundamentally limited. Laws and court rulings that govern PUCs require most to preserve the public interest and to set “just and reasonable” rates. These standards do not require or allow the same kind of commitment that contracts between two private parties require. Furthermore, there are no perfect benchmarks for utility services, so the risk of PBR plans falling out of synch with either a utility’s accounting costs or market realities is real. In view of these considerations, critics of PBR question its ability to truly improve utility resource efficiency.

Questionable Administrative Cost Savings

Anecdotal evidence from state experience with PBR in the telecommunications and energy industries indicates that the reduction in administrative costs arising from less frequent rate cases has been offset in part by increased monitoring and evaluation costs.[8] In addition, pricing flexibility, if allowed, may require that complaint cases regarding unfair competition be held more frequently.

Reduced Quality of Service

By increasing the incentive to cut costs, PBR has been accused of causing service quality to deteriorate. As a result, most utility PBRs are supplemented with some sort of service quality incentive mechanism. However, the balance between the service quality incentive and the primary incentive is somewhat ad hoc, so it is difficult to say whether the supplemental incentive ensures an adequate quality of service. Service quality incentive mechanisms are discussed further in Chapter 3.

Limited Ability to Incorporate DSM, Environmental, and Social Goals

Electric utilities in the U.S. have to varying degrees become vehicles for implementing environmental and social goals. Environmental goals are prominent in many resource planning proceedings for electric utilities. In particular, energy efficiency and other demand-side management (DSM) resources have been promoted by regulators and utilities because of their positive environmental attributes and because of research indicating that imperfections in markets for energy-efficient products prevent their cost-effective penetration (Hirst and Eto 1995). Universal service has been an important social goal and is now reflected in current cost allocation policies and low-income assistance programs (Phillips 1993). Environmental and social programs may benefit society as a whole but tend to reduce utility net revenues and raise rates for nonparticipating customers. We do not justify these goals here but note that PBR increases the incentive to improve performance as measured by the chosen rate or cost index and, similarly to service quality discussed above, tends to divert resources and attention away from nonprice or noncost goals. As a result, utilities are less likely to pursue social and environmental goals vigorously under PBR.

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[8] See for example the monitoring and evaluation program proposed in SDG&E et al. (1993). Similar programs have been set up as part of California's telecommunication PBR plans.

Undesirable Equity Impacts

PBR can affect utility-customer and customer-customer equity in at least three ways. First, PBR mechanisms rely on external measures of cost. Although such external measures are necessary to provide incentives for superior performance, they can lead to above-market returns that will be perceived by some parties to be unfair. Second, PBR mechanisms often have terms longer than the status quo. These longer terms can harm parties who are unhappy with their existing rates because the PBR provides fewer rate cases in which to litigate. Also, because of the increased stakes of rate cases under PBR, customers may become the victims of gaming of the initial rates or of the PBR index mechanism. Third, if a PBR plan allows for pricing flexibility, it will likely lead to a reduction in relative rates for customers or customer classes who have alternatives. As discussed further in Chapter 4, a generally accepted assumption is that a monopolist who serves multiple customer classes subject to a price cap with downward pricing flexibility will move towards inverse-elasticity or Ramsey prices (Lyon 1994; see also Chapter 4 of this report). Despite its ability to improve allocative efficiency, Ramsey pricing has traditionally been unpopular with state commissions because the notion of raising rates of customers who have the fewest alternatives is considered unfair. Flexible pricing under price caps will face the same challenge.

Exemplary Performance is Already Expected Under COS/ROR Regulation

Some regulators view their control over energy utilities primarily in terms of the legal framework in which economic regulation operates. Most states define gas and electric utilities as public utilities who are given monopoly status in return for price regulation and an obligation to serve. Monopoly public utilities have an obligation to deliver goods and services at an acceptable level of quality and reliability for the lowest possible cost (Phillips 1993). The additional financial incentives that are part of PBR mechanisms are considered by critics to be unnecessary and to reduce the importance of existing incentive mechanisms inherent in COS/ROR (Hanaway 1994). These existing incentives include regulatory lag, prudence tests, and the threat of revocation of the monopoly franchise.

CHAPTER 2

PBR Mechanisms: Typology and Design Issues

2.1 Overview

This chapter describes the major types of regulation used for electric utilities. We identify and describe three types of PBR: (1) sliding scale, (2) price or revenue cap, and (3) "menu of contracts." To put PBR in context, we compare it to its primary alternatives, COS/ROR and deregulation. With the various definitions of PBR in mind, we then consider the most important design issues and the coordination of multiple PBR mechanisms.[9] We argue that there is a relationship among rate case frequency, index accuracy, and earnings sharing mechanisms, so these features of a PBR plan should be determined jointly. We also observe that many PBR plans are actually a collection of incentive mechanisms. Even if the main incentive mechanism is broad and powerful, it may be supplemented by a service quality incentive mechanism or a rate or bill incentive mechanism. We discuss ways to approach PBR when multiple objectives are competing.

2.2 Typology of Real-World Methods of Regulation

Table 2-1 presents our typology of the most common types of regulation that have been implemented for public utilities, with a focus on PBR mechanisms that have been proposed or implemented for electric utilities.

Table 2-1 shows a range of regulatory approaches under COS/ROR and PBR. There are two variations on COS/ROR: with and without regulatory lag. For PBR, we show sliding scale, revenue cap, price cap, and menu of contracts. For comparative purposes, we also show price deregulation. Table 2-1 describes each method of regulation according to six features: frequency of rate cases, association with earnings sharing mechanisms, incentive power, information requirements, pricing flexibility, and compatibility with utility-sponsored DSM programs. We also identify at least one case where each method of regulation has been implemented.

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9 PBR design issues are also addressed in EEI (1995).

Table 2-1. Typology of Real-World Methods of Regulation

Feature	Regulatory Mechanisms						
	Cost-of-Service/Rate-of-Return (COS/ROR) Regulation		PBR				Price Deregulation (assuming competition is adequate)
	"Pure"	With Regulatory Lag	Revenue Caps	Price Caps	Sliding Scale	Menu of Contracts	
Rate Case Frequency	HIGH	MEDIUM	LOW	LOW	LOW	LOW	NEVER
Earnings Sharing Mechanism?	N.A.	NO	OPTIONAL	OPTIONAL	YES, by definition	OPTIONAL	NO
Incentive Power	ZERO	MEDIUM	MEDIUM to HIGH	MEDIUM to HIGH	LOW to MEDIUM	HIGH	HIGH
Information Required by Regulator	HIGH	MEDIUM to HIGH: accurate forecasts required	MEDIUM: accounting costs, external benchmark data, possibly demand data			MEDIUM-HIGH: required estimate of the range of firm efficiencies, and demand data	LOW
Pricing Flexibility	LOW	LOW	LOW	HIGH	LOW	HIGH	NONE: perfect competition MEDIUM to HIGH: monopolistic competition
Compatibility with Utility DSM	HIGH	LOW (unless decoupling, shareholder incentives adders)	HIGH	LOW	MEDIUM	LOW	Depends on market for DSM
Implemented Examples	Annual rate cases or FACs	typical base-rate regulation in U.S.	SDG&E, ConEd	PacifiCorp, CMP	Alabama, Mississippi	FCC Regulation of LEC Access Rates	new electric generation

N.A. = Not applicable
FCC = Federal Communications Commission
LEC = Telephone local exchange companies

2.2.1 Cost-of-Service/Rate-of-Return Regulation

In this section we discuss in detail the incentives created by COS/ROR (see Section 1.3 for an introduction to COS/ROR). We differentiate between COS/ROR with and without regulatory lag. COS/ROR with regulatory lag consists of cost-based rates that, once set, are not changed for a significant period of time; this type of regulation is best exemplified by the way electric utility nonfuel rates are typically set in the U.S. COS/ROR without regulatory lag refers to cost-based rates with frequent if not continuous updating for costs. FACs are the most common example of this type of regulation.

Pure COS/ROR

For simplicity, we call COS/ROR without regulatory lag, "pure COS/ROR." Possibly the best known distortion created by pure COS/ROR regulation is the so-called "Averch-Johnson" (A-J) effect (Averch and Johnson 1962). Averch and Johnson show that a firm that is allowed a fixed rate of return above its cost of capital has incentives to:

- use too much capital and too little labor for its level of output, resulting in needlessly high production costs;[10] and
- produce less and charge more than it would if it were not regulated.

An equally vexing albeit less well-known problem of pure COS/ROR is X-inefficiency. X-inefficiency is alternatively known as managerial slack or as a particular case of the "principal-agent" problem. Two regulatory economists, Crew and Kleindorfer (1986) define X-inefficiency as "the excess of production and transaction costs of a particular governance structure over and above the optimal governance mode." Different from the A-J effect, excess costs from X-inefficiency are presumed to come from inefficient use of *both* capital and labor. X-inefficiency implies that managers of regulated utilities do not expend as much effort as managers in competitive firms do. As a result, COS/ROR-regulated firms are less resource efficient.

The principal-agent problem is actually a broad area of economic analysis, covering any problem resulting from an asymmetry of information between a principal (regulator) who wants something done and an agent (utility manager) who actually has to do the work (Train 1991). As applied to X-inefficiency, the principal-agent problem refers to regulators' lack of knowledge about a firm's optimal level of effort and utilization.

[10] This effect is sometimes known as "goldplating." Strictly speaking, the term is a misnomer because the A-J effect does not cause the firm to choose inappropriate kinds of capital, just to use too much of it relative to labor (Train 1991).

The information asymmetry that creates a principal-agent problem can be overcome in two ways. First, the incentives that the principal gives the agent can be changed. This is the underlying motivation behind PBR. Second, the regulators can become “shadow” managers, trying to independently evaluate every utility decision. Traditional integrated resource planning (IRP), which calls for an intensive resource planning process that involves the regulator and the public, may be seen as one way that regulators try to bridge the information asymmetry. Although this effort by regulators reduces the perverse effects of A-J and X-inefficiency, it raises the information requirements and costs of pure COS/ROR. For this reason we label the information requirements of pure COS/ROR to be “high” in Figure 2-1.

COS/ROR with Regulatory Lag

The distortions of pure COS/ROR are mitigated somewhat by an important real-world dimension of COS/ROR. First, one assumption behind the A-J effect is that regulators regulate return only, but COS/ROR regulation in its most common practice is a form of price regulation. Price regulation with infrequent rate cases (regulatory lag) creates an incentive to minimize costs that can reduce both X-inefficiency and the A-J effect. Regulatory lag creates this incentive by giving a regulated firm time to reap the benefits of any productivity-improving activity, such as reducing managerial slack or optimizing the capital/labor ratio. However, unlike PBR mechanisms that intentionally create this incentive, regulatory lag under COS/ROR tends to happen on a more ad-hoc basis: utilities have no guarantee that if they increase their efficiency they will not have the extra earnings taken away from them at the next rate case, nor do they usually know with certainty when the next rate case will be. We indicate that the information requirements of COS/ROR with regulatory lag is “medium to high” because the reduced frequency of rate cases reduces information requirements relative to pure COS/ROR but the reliance on forecasting rather than adaptive benchmarks makes information requirements higher than those for PBR.

2.2.2 Performance-Based Regulation

Sliding Scale

Under sliding scale regulation, prices are adjusted to keep a utility’s rate of return within or close to a deadband.[11] Next to an explicit adoption of regulatory lag, types of sliding scale regulation were some of the earliest forms of incentive regulation (Kahn 1971). If earnings become too large, rates are cut, and, if earnings fall too low, rates are increased (Lyon 1994). It is not COS/ROR regulation per se because the utility’s earnings are not regulated if they fall within the deadband, and adjustments outside of the deadband are sometimes only partial. The primary rationale for sliding scale regulation is to reduce the frequency of rate

[11] A *deadband* is a range around the benchmark or authorized return where no price adjustments are made.

cases in hopes of increasing regulatory lag. Unfortunately, many of the distortions created by pure COS/ROR can also appear in sliding scale regulation. If the deadband is narrow and the rate adjustments are made regularly, then a utility may have even less incentive to control costs and labor efficiency than it would under COS/ROR regulation with regulatory lag. In Table 2-1, we rank the incentive power of sliding scale mechanisms as low to medium. The similarity of sliding scale plans' range of incentive power to the range of incentive power shown for COS/ROR is no accident because sliding scale's incentives in fact oscillate between those of pure COS/ROR and COS/ROR with regulatory lag. When a utility is outside its earnings deadband, the incentives are like those of the former, and when it is within its earnings deadband, the incentives are like those of the latter. Ultimately, the incentive power depends greatly on the size of the deadband and the sharing fraction chosen.

Today, sliding scale most often appears as a mechanism that supplements a price or revenue cap. Used in this way it is called an *earnings sharing mechanism*. A vigorous debate exists over whether earnings sharing mechanisms increase or decrease the overall benefits of a PBR plan; this debate also applies to the efficacy of sliding scale regulation. We discuss alternative forms of earnings sharing in Section 2.3.3, below.

Revenue Caps

Under revenue cap regulation, a regulator caps a utility's allowed revenues. The most common formulation of a revenue cap is as follows:

$$\overline{R}_t = (\overline{R}_{t-1} + CGA \times \Delta Cust) \times (1 + I - X) +/- Z \qquad \textbf{(1)}$$

where:

$\overline{R}_t$	=	authorized utility revenues for in time t
CGA	=	customer growth adjustment factor ($/customer)
ΔCust	=	annual change in the number of customers
I	=	annual percent change in prices (change in inflation index)
X	=	productivity offset
Z	=	adjustments for unforeseen events beyond management's control

A utility is permitted to maximize its profit margin below the revenue cap, presumably by minimizing total costs. The revenue cap is subject to an index that is beyond a utility's control but allows for changes in nominal prices (inflation) and productivity. (We discuss the types of indexing methods below in Section 2.3.) Earning sharing mechanisms are usually combined with revenue caps to guard against the failure of the index to keep returns within acceptable bounds. A fixed term and a preset revenue formula give the firm increased certainty with regard to its share of any productivity improving behavior. It is this certainty that ideally frees a utility to choose a more economically efficient mode of operation than it might choose otherwise. In this regard, a revenue cap is superior to COS/ROR or sliding scale regulation. A variation on the revenue cap is the revenue-per-customer (RPC) cap. Under this form of regulation, the revenue cap index has a component that is directly proportional to a utility's number of customers. Equation 2-1 is a generalized form of a revenue cap. If the CGA term is equal to average revenues per customer (ARPC), then it is equivalent to an RPC cap. If the CGA term is equal to zero, the formula is a simple revenue cap.

Although it may appear that revenue cap regulation is novel compared to price regulation under COS/ROR, a form of revenue cap regulation exists already in many states. Electric Revenue Adjustment Mechanisms (ERAMs) or revenue decoupling mechanisms essentially turn traditional base-rate ratemaking from price regulation into revenue cap regulation. Decoupling mechanism have been adopted or experimented with in several states including California, Washington, New York, and Maine (Marnay and Comnes 1992). Whether COS/ROR with a decoupling mechanism constitutes incentive regulation, however, depends on the degree of regulatory lag.

Two features of revenue caps can decrease their simplicity. First, revenue caps are often applied to a subset of a utility's revenues. For example, the three revenue caps proposed by California electric utilities exclude revenues to cover fuel costs. Revenues excluded by revenue caps may be subject to a separate PBR or to business-as-usual regulation. Second, revenue caps, by definition, do not address final retail prices. As will be seen in Chapter 4, it is unwise to allow a utility complete flexibility in setting prices under a revenue cap. Therefore, revenue caps should coexist with business-as-usual methods of allocating costs and setting relative prices among customer classes.

Price Caps

Under price caps, prices for monopoly utility services are set for long periods of time without regard to the utility's own costs. COS/ROR regulation in the form of rate freezes or significant regulatory lag may be viewed as price cap regulation. In their most general form, however, price caps are determined by an index for groups or *market baskets* of goods:

$$\overline{P}_{m,t} = \overline{P}_{m,t-1} \times (1 + I - X) +/- Z \qquad \textbf{(2)}$$

where:

$\overline{P}_{m,t}$	=	utility price for market basket m in time t
I	=	annual percent change in prices (change in inflation index)
X	=	productivity offset
Z	=	adjustments for unforeseen events beyond management's control

Equation 2-2 is commonly known as in the UK as the "retail price index (RPI) minus X" and, in the U.S., as the "consumer price index (CPI) minus X" formula. It has been widely applied in telecommunications incentive regulation.

Initial Comparison of Revenue and Price Caps

We consider the information requirements of both revenue and price cap regulation to be "medium." In addition to the utility's own costs for the initial cap level, information on reasonable indices is also required. If the regulator wants to incorporate the possible demand changes that result from price changes, demand elasticity information is also necessary. Although PBR requires some new information compared to COS/ROR, we consider the information requirements of revenue and price caps to be less than those of COS/ROR if the regulator is trying to overcome information asymmetries.

Revenue and price caps create the same incentives to minimize costs. They both help to eliminate A-J and X-inefficiency effects that are a problem with pure COS/ROR. For example, a utility that, under COS/ROR, is biased towards building power plants instead of purchasing power will lose that bias under PBR. Revenue and price caps differ significantly, however, in terms of the incentives they provide for incremental sales. Under price caps, a utility will typically have an incentive to increase sales up to the point where marginal revenues equal marginal costs. In view of the starting point of many electric utilities where energy rates are typically considered to be above long-run costs, the incentive to increase sales is great. This sales-maximization incentive does not exist under revenue cap regulation, however, because revenue caps are set without regard to changes in sales during the PBR period. On the other hand, revenue caps create incentives for the utility to minimize sales (either by raising price or by other means) as a way of reducing costs, and price caps provide the incentive to move towards welfare maximizing (Ramsey) pricing. We examine the differences between price and revenue caps, including their differences with respect to utility-sponsored energy efficiency, in detail in Chapter 4.

Menu of Contracts (Bayesian Mechanism)

The "menu of contracts" is also known as a Bayesian mechanism in that it relies heavily on regulators' prior or subjective estimation of the true distribution of firm efficiencies (Lyon, 1994). This method of regulation is an interesting variation on price caps. Under the menu-of-contracts method, the regulator sets multiple contracts with the utility. Each contract has a different price cap and an associated bonus. The bonus is inversely proportional to price; i.e., the bonus is higher if the firm accepts a lower price cap. The menu-of-contracts method capitalizes on the reasonable assumption that, although every firm subject to COS/ROR is vulnerable to X-inefficiency and A-J distortions, potential efficiencies of each firm under PBR differ. Some firms may have more "fat" to cut or, more accurately, possess more fat-cutting know-how. If cap/bonus combinations are chosen carefully, a win-win situation can result. Firms that are inherently most efficient (regardless of their starting point) will choose the lowest price cap offered. They have no trouble meeting the cap and making money on every unit produced. Further, they will also receive the largest bonus. Less efficient firms, rather than fight PBR or go out of business, can choose a higher price cap. Customers benefit, because in all cases efficiency is enhanced and because, in theory, the total payment is less than what customers paid for under COS/ROR.

The drawback of the menu-of-contracts method is that, compared to price or revenue caps, it requires that more information be obtained or more assumptions be made up front. The regulator must guess at the distribution of firm efficiencies and carefully compute bonus payments that make each cap/bonus selection in the menu lucrative to the firm and make the firm reveal its true efficiency. Also, most regulators balk at the notion of paying out fixed bonuses. We suggest, however, that the menu-of-contracts method deserves further consideration by energy regulators. It is especially worth considering when a regulator is applying PBR for a group of similar firms, such as regional distribution companies. During 1994 and 1995, the Federal Communications Commission (FCC) essentially adopted menu of contracts for the regulation of access rates for local exchange companies (Andrews 1995; Sappington and Wiesman 1994). Under the FCC approach, each firm is given a default price index, which represents the price cap for a relatively inefficient firm. Each firm has the option of choosing two other increasingly stringent indices. Only firms that consider themselves low cost will choose tougher indices. Rather than pay up-front bonuses to the firms accepting tougher indices, the FCC increased the point at which revenue sharing occurs; thus, efficient firms are given the opportunity to realize higher profits by accepting lower prices. This variation on the menu of contracts appears to be a clever way to provide bonuses in a manner that may be acceptable to regulators and customers.

2.3 Pivotal Design Issues

With types of PBR defined, it is now possible to examine the issues that are most important in determining the efficiency of a PBR plan. From an economist's perspective, some of the most important design issues of PBR are scope, minimum length of commitment (or term), degree of commitment, method of indexing, and method for sharing earnings.

2.3.1 PBR Term and Commitment

Term

The term is an important attribute of a PBR plan. During the term of the plan, the utility has the opportunity to capture the benefits of productivity-improving investments. When terms are short, utilities become subject to the *ratchet effect* (Lafont and Tirole 1993), under which they will not even try to make a cost-effective investment because they may not recoup their productivity-improving investment and will have to try harder in the future just to break even.

The power of term may be illustrated using a simple example. Suppose a utility is subject to a revenue or price cap and is considering a cost-reducing investment. How much of the investment it can expect to recoup depends directly on the PBR plan's term. Under a PBR plan with a term of three years, a utility can, by definition, fully recoup an investment that has a three-year payback but would only recoup 60 percent of an investment that had a six-year payback and less than 40 percent of one with a 25-year payback.[12] Faced with these facts, a utility subject to a PBR with a short term will only pursue investments with relatively short paybacks.

Commitment

Commitment refers to the extent of the regulator's and utility's agreement to abide by the terms of the PBR plan. A plan's term has an important effect on commitment as does the probability that either party will renege on the contract. In the U.S., most electric utilities interact with their regulators not under contract law but under state public utilities' laws requiring that rates be just and reasonable and not be confiscatory to the utility. Furthermore, many U.S. public utility commissions claim that the actions of a previous commission cannot bind the actions of future commissions. Thus, most commitments in PBR plans must be subordinate to changes in politics and perceptions of "unacceptably" high rates or low profits.

[12] This example assumes a discount rate of 12%/year.

As a result of commitment problems, PBR plan terms are short in contrast to the payback periods for many investments made by utilities. As will be seen in Chapter 3, PBR terms tend to vary from three to six years although many investments have payback periods of 10 to 30 years. In addition, significant levels of uncertainty exist regarding the probability that a PBR plan will complete its full term. PBR plans have been canceled or had their attributes significantly altered. For example, during the late 1980s, NYNEX (a local telephone company) requested suspension of a rate freeze from the New York Public Service Commission (NYPSC) after profits fell because of an unexpected drop in demand. More recently, the regulator of electric distribution utilities in England and Wales proposed to change the terms of a five-year rate cap plan after only one year of operation ("Incredible" 1995). This action caused a drop and considerable volatility in the utilities' stock prices. It also diminished the regulator's credibility. These examples indicate that utilities and regulators can have trouble maintaining commitment. We do not formally prove this, but it seems clear that the credibility gap caused by a real or perceived inability to commit cancels some of the power provided by a long PBR plan term.

Because uncertainty about a plan's term appears to be as important as the actual length of the term, it is important to set realistic terms and lengths and to make efforts to assure all parties will stick by them. Various mechanism to improve plan viability exist, including earnings sharing mechanisms, allowances for unforeseen events (commonly known as *Z factors*), and conditions under which portions of the PBR are automatically suspended (off ramps). Although these mechanisms reduce the power of PBR plans, they have value because they provide ways to adjust a PBR plan before political forces undermine it. Another way to improve commitment is to strive for extensions of PBR plans without rate hearings. By holding out the option of an extension of a PBR plan, a regulator can create the perception of potential future PBR incentives beyond the term of the current plan.

2.3.2 Indexing Methods

Rate or revenue freezes create powerful incentives to improve productivity. When rate cases are infrequent, authorized revenues or rates become the cap even if there is no explicit index. Despite the powerful incentives created by freezes, they clearly become inaccurate over time. Indexing rates or revenues can improve the accuracy of the PBR target and improve the viability of a PBR plan.[13]

The primary challenge of indexing is choosing indices that *accurately* measure a utility's opportunity costs. Also, indices should be relatively quick and easy to compute and should not be subject to manipulation by the utility. The importance of accuracy is illustrated in

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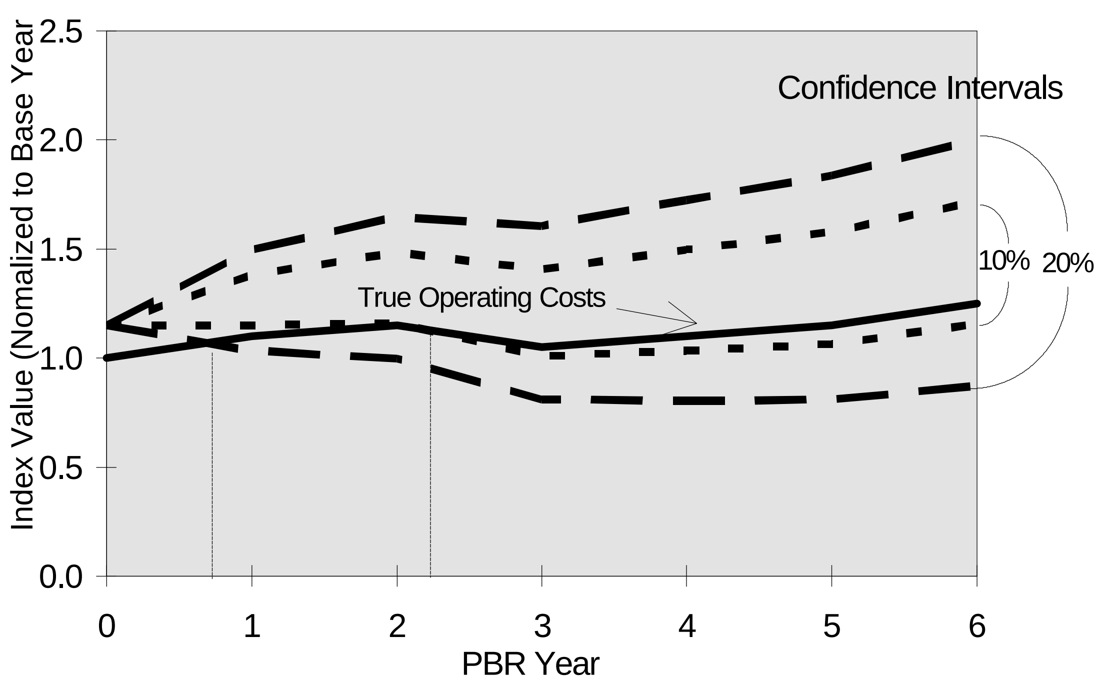
[13] Indexing between rate cases is not new. In response to the high inflation rates of the 1970s, many PUCs adopted *attrition mechanisms* that allowed for semiautomatic adjustments to rates between rate cases.

Figure 2-1. The figure shows a PBR plan with two competing price indices that both begin 15 percent above unit operating costs. The 15 percent could be thought of as a firm's margin or net revenues. It is intuitively reasonable that the PBR plan would be in jeopardy when the index fell below operating costs; at that low level, the utility would be losing money. Even if both indices started out at the correct level and were both unbiased[14] over time, their accuracy would decrease over time.[15] The figure shows dotted and dashed bands corresponding to standard deviations (confidence intervals) of both of the indices. Year-one standard deviations are equal to 10 and 20 percent, respectively, of the initial index value. Although only an illustration, the figure shows that a change in accuracy has a disproportionate effect on the viability of a PBR as measured in years. The index with a 10 percent standard deviation would, after 2.3 years had passed, have a 68 percent chance of falling below operating costs and becoming nonviable. In contrast, the index with a 20 percent standard deviation would reach a 68 percent chance of becoming nonviable in only 0.7 years.

Figure 2-1. Index Accuracy Affects Viability of PBR



[14] By *unbiased*, we mean that, although there is uncertainty in the accuracy of the index, it has an equal probability of being high or low relative to the true index value.

[15] Over time, the confidence interval of a simple, time-dependent forecast grows as follows: $CI_n = CI_1\sqrt{n}$, where *CI* is the confidence interval and *n* is the time period.

Where does one find an accurate index? A utility's recorded costs are reasonably accurate, but recorded costs, unless updated very infrequently, are counterproductive because they result in pure COS/ROR regulation by another name. Finding good *external* measures is necessary but difficult. Below, we discuss the three most common types of indices: "CPI minus X," railroad style, and yardstick.

RPI minus X or CPI minus X

The most widely known PBR index is the CPI (or RPI) minus X or the telecommunications style index. Its typical form was introduced in Section 2.2.2, above. The primary advantage of CPI minus X indexing is its simplicity. Prices[16] are capped using a widely understood measure of inflation, such as the CPI; then, prices are adjusted, usually downward, from the CPI increase by a fixed X factor, which accounts for productivity.

To retain simplicity, most CPI minus X indices retain common, economy-wide measures of price inflation. In the U.S., common price inflation measures include, in addition to CPI, the gross national product price deflator (GNP-PD) and the gross national product price index (GNP-PI). The key design issue for CPI minus X regulation is the selection of X. Because the price inflation index is multisector in nature, it includes the effects of existing average productivity. For these indices, the X factor should only include the incremental productivity expected for the industry (or firm) over the productivity of the economy. Usually X is first set using historical data on national productivity, public utilities, or the electric industry.[17] It is reasonable to expect that individual firms subject to PBR will outperform historical industry trends, however. To ensure that customers receive a share of the expected enhanced productivity, it is not uncommon to add to *X* a factor called a *consumer productivity dividend* or *stretch factor*.

Railroad Style Index

Another approach to price indexing that retains the inflation/productivity formula is known as a railroad-style index.[18] Railroad indices use measures of industry input prices rather than national measures of output prices. X factors in railroad-style indices should include all

16 For simplicity, we focus on price cap indices at this time. In Chapter 3, we show that the CPI minus X index when applied to revenue caps also needs to have a factor for growth in numbers of customers.

17 Various measures of historical productivity are published by the U.S. Bureau of Labor Statistics (BLS). Unfortunately, a specific electric utility productivity index is not available from the BLS, but the results of a private study on electric industry productivity are available in Hill (1995).

18 The term came from its use in the price cap regulation of certain U.S. rail carriers (Lowry 1991).

expected productivity for the industry. Thus, in railroad-style indices, one might expect X factors to be higher than in telecommunications-style indices, all other things being equal. If historical data are used as a starting point for estimating X, and if it is expected that the firm may be able to outperform historical industry statistics, it is appropriate to consider adding a stretch factor, similar to the telecommunications-style index.

Yardstick Indices

Yardstick indices compare performance of a utility directly to the performance of similarly situated utilities; typically, a utility's prices or bills are compared to those of a peer group of utilities. The data used are firm-specific or regional rather than national. A simple yardstick index would base a utility's prices on both its own costs and either the prices or costs of a group of firms within a peer group:

$$\bar{P}_{i,t} = pC_{i,t} + (1-p)\sum_{j=1}^{N}(f_j C_{j,t}) \tag{3}$$

where,

$\bar{P}_{i,t}$	=	overall price cap for firm i in year t
p	=	share of own-firm cost information used
$C_{i,t}$	=	unit cost of firm i in period t
f_j	=	revenue or quantity weights for peer group firms j
$C_{j,t}$	=	unit costs (or prices) for peer group firms j
N	=	number of firms in peer group

Because yardstick measures compare output prices or bills, they do not need an explicit productivity adjustment. One can vary the yardstick standard that the utility is trying to beat. For example, one utility may challenged to beat the average of its peer groups, and another may be rewarded for staying out of the bottom quartile.

Yardstick indices are of particular value when several regional utilities have cost characteristics that are correlated with each other (Armstrong et al. 1994). Despite their theoretical attractiveness, yardstick indices for U.S. energy utilities tend to be reserved only for supplemental measures rather than for primary-rate or revenue caps. The thing that comes closest to yardstick regulation of energy rates in the U.S. is the indexing of California utility gas prices to the purchase prices paid by other western buyers. Reluctance to use yardstick regulation appears to be a result of the potential volatility of such measures, which leads utilities to fear that these measures inaccurately reflect utility costs. Also, from the customer's viewpoint, there is little assurance with yardstick measures that prices will stay below inflation. Yardstick indices necessarily rely on a smaller sample of firms in the economy than do CPI minus X indices. Actually, if the volatility resulting from a yardstick index can be measured, it is possible to find the optimal ratio of yardstick and own-utility cost information in the setting of the index (Armstrong et al. 1994). Unfortunately, there are sometimes no historical data on peer groups, and new peer group data sometimes take longer to obtain than widely published data like the CPI.

2.3.3 Earnings Sharing Mechanisms

Earnings sharing mechanisms track actual earnings, and share with ratepayers any earnings that fall below or exceed certain thresholds. Mechanistically, this tracking is done by accruing excess or shortfall earnings in a tracking account and adjusting future rates to amortize the account balance. Earnings sharing is really just another term to describe sliding scale regulation although, when it is called earnings sharing, the mechanism is usually being proposed in conjunction with a price or revenue cap. Earnings sharing mechanisms and earnings limits represent a departure from COS/ROR ratemaking in which the norm is that, at least between rate cases, utilities retain all deviations in their earnings. Although they reduce the incentive power of PBR, earnings sharing mechanisms and review triggers appear to be quite popular, as will be seen in Chapter 3.

The design of earnings sharing mechanisms has been controversial. Utilities tend to favor giving shareholders all initial earnings above or below benchmark returns. Thus, the initial incentive power of the plan is 100 percent on both sides of the benchmark return. We define this type of earnings sharing mechanism as the *symmetric model* (Figure 2-2, solid line). A variation on the symmetric model is to have the marginal incentive power of 100 percent limited to a deadband around the benchmark return. Above and below the deadband, earnings are shared (as shown in Figure 2-2), the PBR is reviewed, or a combination of the two occurs. Competing with the symmetric model is the *customer sharing model* favored by certain consumer representatives and economists. Supporters of the customer sharing model argue that above-benchmark utility earnings should be shared heavily with ratepayers (Marcus and Gruenich 1994; Navarro 1995). The customer sharing model results in a marginal incentive power that starts low and grows with above-benchmark returns (Figure 2-2, dashed line).[19] Only at high levels of earnings above the benchmark would a utility get to keep most of its incremental earnings. (However, the marginal incentive power should fall again as truly extraordinary earnings are reached and the sharing mechanism returns or the PBR plan is suspended.)

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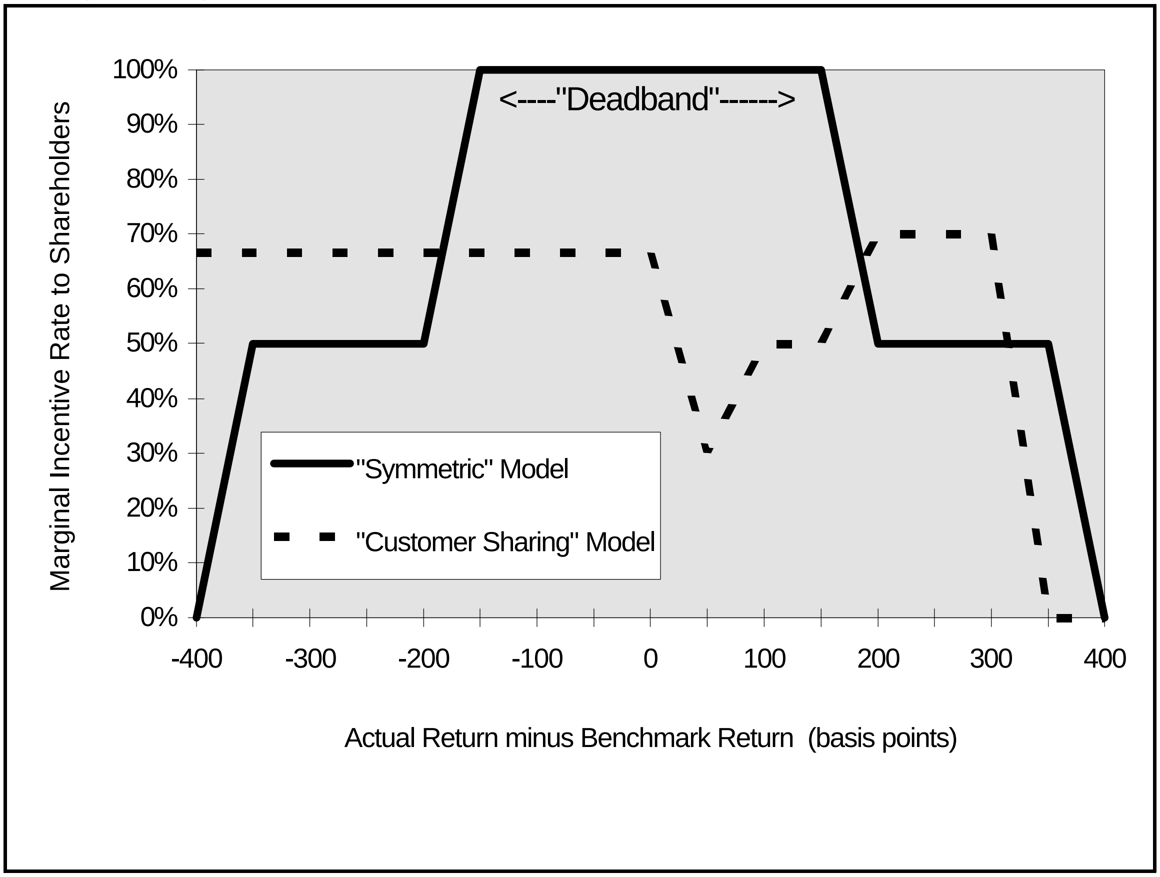
[19] The example of the customer sharing model illustrated in Figure 2-1 is based on the proposal sponsored by Navarro (1995) in the SDG&E PBR proceeding.

Figure 2-2. Marginal Incentive Power of Symmetric and Customer-Sharing Models of Earnings Sharing



Discussion

Standard economic theory says that a utility's best incentive to pursue productivity-improving investments is that it receive 100 percent of the return on any incremental investments. Providing anything less will lead the utility to forgo some beneficial investments. No earnings sharing mechanism or a symmetric mechanism with a large deadband is most consistent with standard economic theory. As regulators gain experience with incentive regulation and become more confident of benchmarks and productivity offsets, it is reasonable to expect that, under the standard model, deadbands will be widened or earnings sharing mechanisms will be eliminated entirely. This appears to be the approach taken in telecommunications incentive regulation.

The symmetric model raises fairness and equity issues because ratepayers do not get a share of above-normal returns. Supporters of the symmetric model argue that, rather than offer a high sharing rate, the best way to provide consumers with a fair share of the net benefits is to provide them with lower prices or revenues via an aggressive starting point or stretch factor to the productivity offset. If customers receive their share of the PBR benefits in a stretch factor or low starting point, the marginal incentive power to shareholders is not diluted, and customers are guaranteed their share of benefits so long as the firm's earnings remain in or around its benchmark.

On the other hand, supporters of the customer sharing model make two main arguments for high initial sharing rates on above-benchmark returns. First, certain economists have extended the standard model of economic welfare to consider political or equity considerations explicitly. In these models, an incentive mechanism's benefits to consumers are weighted more heavily than benefits to producers. Under certain assumptions, these models find that high sharing fractions are preferable to low sharing fractions because stretch factors, although they guarantee benefits to consumers, must be determined in advance (Gasmi et al. 1994). A chance exists that the chosen stretch factor will too low; thus, it may be better to give ratepayers an ongoing share of profits as profits materialize. Further, high sharing fractions can allow for a utility's prices to better track its realized costs, which can improve allocative efficiency (Lyon 1995).

The second argument for high initial sharings mechanisms is that many "cheap" productivity-enhancing opportunities exist. These opportunities may be lucrative to the utility even if it only recoups a small fraction of the benefits. Less ratepayer sharing is only needed at higher levels of incremental earnings where productivity improvement opportunities are more expensive and the need for larger utility incentives is greater (Navarro 1995). Under this reasoning, a utility would make the same investments with or without the high initial ratepayer share. That is, the same outcome is achieved so long as the ratepayer's share decreases at higher levels of incremental earnings. (As shown by the dashed line of Figure 2-2, at very high earnings, the ratepayers' share of earnings variations would again increase to avoid "obscene" profits.) However, overall ratepayer net benefits are increased if ratepayers get to keep a larger fraction of benefits of the initial "cheap" investments. Thus, this argument is ultimately an argument for customer equity.

2.4 Coordination of Multiple Incentives

Although not often discussed, coordination of multiple incentives articulated in a PBR plan is important. Even plans that are considered comprehensive in scope have different marginal incentive powers on different revenue or service categories. In addition, some plans overlay the primary rate or revenue cap with supplemental incentives. There may be good reasons to have differential marginal incentive powers or overlapping incentives, but we believe they are an invitation to misunderstanding and ambiguity. At a minimum, we suggest that designers of PBR plans make the relationships among multiple incentives explicit for the following reasons.

First, as will be seen in Chapter 3, several plans have different incentive powers on different categories of costs; these plans run the risk of causing uneconomic investment and expenditure decisions. Take, for example, a utility that has a different marginal incentive power on its base rates and fuel rates. Typically, the incentive power on the base rate is higher than on the fuel rate. The utility will have an incentive to underinvest on generation-related capital even though such underinvestment may increase heat rates and, ultimately, fuel expenses. In other words, a dollar saved by cutting generation-related cost adds more to the utility's bottom line than the dollar lost in the fuel expense budget. Empirical evidence supports this concern. Before the introduction of the comprehensive plans reviewed in this report, incentive regulation in the electricity industry consisted mainly of targeted incentives which, by definition, means that different marginal incentive powers apply to different services or cost categories. Economists are generally distrustful of the differential marginal incentive powers caused by targeted incentives, and empirical work has provided little evidence that these rates are useful in decreasing overall costs (Berg and Jeong 1991 and 1994; Graniere 1993).

Second, poorly designed, overlapping multiple incentives can cause suboptimal behavior. As will be seen in Chapter 3, several revenue cap mechanisms have supplemental bill and/or rate indices in addition to a broad revenue index. Other plans supplement rate or revenue caps with service quality incentive mechanisms. It is reasonable that a revenue index include a supplemental index for rate performance. Similarly, there is good reason to penalize a utility for degrading service quality. But, as will be seen in subsequent chapters, few PBR plans show transparently how the utility trades the potential value of its main rate or revenue cap with its supplemental incentives.

CHAPTER 3

Review of Electric Utility PBR Plans

3.1 Overview

In this chapter, we review PBR mechanisms that have been proposed or implemented by electric utilities. We refer to PBR mechanisms as *plans* and describe them generally, and analyze them in terms of eleven characteristics:

- minimum term (length of time utility agrees to stay out of rate case),
- primary method for cap-setting,
- treatment of generation fuel costs,
- existence and type of earnings sharing mechanism,
- criteria for exclusions, or "Z" factors,
- existence and type of supplemental rate or bill incentives,
- incentives for utility demand-side management (DSM),
- existence and criteria for supplemental service quality incentives,
- flexibility of pricing,
- coordination of multiple incentives, and
- overall incentive power.

The primary purpose of this chapter is to describe the choices made by early adopters and proposers of electric PBR in these eleven critical areas and identify some initial trends. A systematic analysis of results is not feasible because only about half of the plans have been implemented, and those have not been in place for long.[20] However, an understanding of the design of these plans is useful for utilities and regulators who will consider PBR plans in the future.

3.2 Approach

Our sample includes a majority of all U.S. PBR plans that (1) have been implemented or proposed by U.S. electric utilities and (2) are broad in scope. We either describe the PBR plan as implemented, or we describe the utility's initial filed plan. We include both implemented and proposed PBR plans because comprehensive PBR plans are still relatively uncommon. In Volume II, Appendix A, we provide detailed summaries of the individual

[20] Some aspects of SDG&E's PBR plan have been in place for approximately two years, and evaluation reports are available. See Vantage Consulting (1995) and DRA (1995).

plans. We acknowledge that there may be some utility bias in the proposals because they have not undergone the scrutiny of PUCs or intervenors in the negotiation or litigation process.

3.2.1 Description of Sample

Table 3-1 lists the 11 plans we reviewed and provides important information regarding the scope and general nature of each PBR plan in our sample. Only seven (PacifiCorp, CMP, NYSEG, SDG&E, ConEd, Mississippi, and Alabama) of the 11 plans have been implemented; the rest are still in the proposal stage.[21] Although we include utilities from six states, seven of the plans are sponsored by utilities in just two states: California and New York.

In Chapter 2, we categorized real-world PBR mechanisms into three types: price caps, revenue caps, and sliding scale mechanisms. Revenue caps have been implemented for Consolidated Edison (ConEd) and San Diego Gas & Electric Co. (SDG&E) and have been proposed for Southern California Edison (SCE) and Pacific Gas & Electric Co. (PG&E). Price caps have been implemented by PacifiCorp, Central Maine Power (CMP), and New York State Electric and Gas (NYSEG) and have been proposed by Niagara Mohawk Power Co. (NMPC) and Tucson Electric Power (TEP). Although its primary proposal is a revenue cap, PG&E has proposed a price cap for its larger industrial customers. Sliding scale mechanisms have been implemented by Alabama Power (Alabama) and Mississippi Power (Mississippi). The sliding scale plans have been in place the longest. Alabama's mechanism has been in place since 1982 and Mississippi's since 1986. Although sliding scale plans are broad in scope, their incentive power is inherently limited (see Chapter 2). The more powerful price and revenue cap plans did not appear until late 1992 when SDG&E proposed its plan, and PacifiCorp's price cap was approved in 1993.

A PBR's scope may be defined by how much of a utility's operations, in terms of percentage of retail customers or costs, are governed by the PBR. All the plans we review apply to sales to all retail customers. Cost coverage is more varied. Several of the plans claim to cover a high fraction of costs, but there are many exceptions. PG&E's proposals exclude fuel and purchased power, for example, and SDG&E's plan excludes cost of capital, fossil plant efficiency, and nonutility purchased power costs. Some of the plans exclude DSM budgets (for further discussion, see Section 3.3.8). We compare plan coverage systematically in Section 3.3.12 when we evaluate the overall incentive power of the plan.

[21] A clarification regarding "proposed" and "implemented" is in order. SDG&E's mechanisms have been billed "experimental;" our interpretation of that label is that it enables either the utility or regulator to claim that no regulatory precedents are being set by the plan. SDG&E's plan has been as thoroughly reviewed and analyzed as any other implemented plans. See Volume II, Appendix A.

Table 3-1. Sample of Electric Utility Performance Based Regulation Plans

	Company	Utility Type	Plan Title	Plan Type	Term (yrs) † w/ PBR	Term (yrs) † w/o PBR	Scope	Regulatory Status ††
1.	Central Main Power (CMP)	Electric (Elec.)	Alternative Rate Plan	Price cap	5	3‡	All retail rates	Approved December 1994
2.	NY State Electric & Gas (NYSEG)	Combi-nation (Comb.)	Revised Settlement Agreement	Price cap	3	3‡	Flow-through allowed for low-income DSM, and excess R&D expenses.	Proposed April 1995; Approved September 1995
3.	Niagara Mohawk Power Co. (NMPC)	Comb.	Phase II	Price cap	5	3‡	All retail rates	Proposed Feb. 1994; Delayed April 95
4.	PacifiCorp	Elec.	Alternative Form of Regulation	Price cap	3	3	Calif. only. All prices with no pass-throughs.	Approved December 1993
5.	Tuscon Electric Power (TEP)	Elec.	Incentive Ratemaking Proposal	Price cap (freeze)	5	n.k.	All retail rates	Proposed June 1995
6.	Consolidated Edison of NY (ConEd)	Comb.	Agreement & Settlement	Revenue per customer cap	3	3‡	Pass-throughs for IPP capacity costs, pensions, DSM program costs, and renewables	Approved April 1995
7.	Pacific Gas & Electric Co. (PG&E)	Comb.	Regulatory Reform Initiative	Base-rate revenue cap, price cap	6	3	Revenue cap on nonfuel expenses. Price cap for large industrial customers.	Proposed in 1994; case before PUC
8.	San Diego Gas & Electric Co. (SDG&E)	Comb.	Base-Rate Mechanism	Base-rate revenue cap	5	3	Certain nonfuel expenses	Adopted August 1994
			& Generation and Dispatch Incentive	Modified price cap	2	1	Some fuel & purchased power costs	Adopted July 1993
9.	Southern California Edison (SCE)	Elec.	Non-Generation PBR	T&D revenue cap	6	3	All nongeneration revenues	Proposed in August 1994
			& Fossil Generation Transition Mechanism	Modified price cap	8	1	All fossil generation rev. requirements	Proposed July 1995
10.	Alabama Power	Elec.	Rate Stabilization & Equalization	Sliding scale	Indef.	n.k.	All retail rates	Approved in 1982
11.	Mississippi Power	Elec.	Performance Evaluation Plan (PEP) I & II	Modified sliding scale	Indef.	n.k.	All retail rates	PEP I adopted Dec. 1990. PEP II adopted January 1994

† Terms include the litigated base year plus the number of years subject to indexing. †† As of September 1995 ‡ estimate n.k. = not known

3.3 Comparative Review

3.3.1 Minimum Term

As a result of PBR, the median time between rate cases in our sample of utilities increased. It was three years before PBR and five after— a modest improvement (Table 3-1). Typical practice varies, but one analysis of published rate case data indicates that the mean time between rate cases in the U.S. is three years and the median time is approximately two years (Eto et al. 1994, pp. 11-12). Thus, prior to PBR, the utilities in our sample appear to be typical.

Not all plans require that a rate case be conducted at the end of the PBR period. Some plans will be extended with little or no adjustment to the cap. However, as long as there is a significant *chance* of a rate case, the utilities incentive is dulled because any benefits from improved productivity may be taken back by the regulator.

As discussed in Chapter 2, the inability of a regulator or the utility to commit to long terms can negate the potential benefits of PBR. Clearly the legal and political limits on existing regulation affects the terms in our sample shown in Table 3-1. Further, although the terms represent an improvement over the status quo, the risk of premature suspension of PBR still exists.

3.3.2 Price or Revenue Cap Indices

The heart of any broad PBR mechanism is how revenues or rates are set over time. The simplest method is to freeze revenues and rates. Usually this is unsatisfactory to the utility because of the committment to stay out of a rate case for a period of time. Instead, prices and revenues are typically adjusted annually according to a formula that includes a factor for the general change in prices (inflation) and a productivity offset.

Price Cap Plans

In our sample of utility plans, we observe four price cap plans that follow an index format: NMPC, CMP, PacifiCorp, and PG&E (industrial customers only) (Table 3-2.). NYSEG has agreed to a specific trajectory of prices. TEP has proposed a rate cap in the form of a rate freeze so it is excluded from the table.

The choice of inflation measures and methods of determining the productivity factors are different for each utility. Three price cap plans use telecommunications-style indices; i.e., they use economy-wide price for their price (inflation) indices. The table shows that inflation indices used include the consumer price index (CPI) for NMPC, the gross domestic product

(GDP) implicit price deflator for Central Maine Power, and the producer price index (PPI) for PG&E. In contrast, PacifiCorp used a railroad style index with a price index based on a weighted average of price indices that represent inputs to its business: capital, fuel, materials, and labor.

Table 3-2 shows a wide range of adopted productivity offsets for the price cap plans, from 0.2 to 1.4 percent per year. These productivity offsets are less than those that have been adopted in telecommunications price cap regulation; adopted offsets are typically in the range of three to five percent per year in telecommunications.

Table 3-2. Inflation Indices and Productivity Offsets Used in Price Cap Plans

$$\overline{P}_{m,t} = \overline{P}_{m,t-1} \times (1 + I - X)$$

Utility	Applicable Rate (P_m)	Inflation factor (I)	Productivity Offset (%/yr) (X)	Basis of Productivity Offset
NMPC	All rates	CPI	0.2%	Multiyear total factor productivity study
CMP†	All rates	60%-100% of IPD-GDP	normally 0.625% with range of 0.5% to 1.0% depending on year and level of I	Settlement values
NYSEG	All rates except industrial	2.9% in year 1, 2.8% in year 2, and 2.7% in year 3	None explicit	N.A.
PG&E	Large Electric Manufacuturers Class (LEMC)	PPI for industrial electric power	0.5%	Company proposal based on assumption that PPI already captures some productivity
PacifiCorp	Base rates	Weighted average of DRI's indexes for capital, fuel, materials, and labor	1.4% in year 1, recalculated annually	CPUC staff total factor productivity methodology

Notes: †See Volume II, Appendix A for complete formula.
CPI = Consumer Price Index.
IPD-GDP = Implicit Price Deflator for Gross Domestic Product
CPUC = CA Public Utility Commission
PPI = Producer Price Index

A productivity offset has a close relationship to the inflation index used. As noted in Chapter 2, telecommunication-style indices rely on economy-wide measures of inflation, which already include average economy-wide productivity adjustments. For these indices, the productivity adjustment should only include the incremental productivity expected for the industry (or firm) over the productivity of the economy. In contrast, PacifiCorp's railroad-style price index uses an input cost index and its productivity offset should include all expected productivity for the firm. Thus, it is not surprising that PacifiCorp's productivity

offset is considerably higher than the other utilities.
NYSEG's approach to its price cap is simply to set yearly price adjustments in advance. Thus, NYSEG is taking on the risk if inflation rates change in the future.

Revenue Cap PBR Plans

Four utilities (SCE, SDG&E, ConEd, and PG&E[22]) have proposed or adopted revenue caps rather than price caps as their primary index mechanisms (Table 3-3). As described in Chapter 2, a key difference between revenue caps and price caps is that revenue caps generally decouple authorized revenues from sales, so some sort of recoupling to growth in the number of customers is necessary. Coupling to customer growth is accomplished by the CGA x ΔCust term. Similar to price caps, revenue caps adjust for inflation, productivity, and unforeseen events.

An important difference between price and revenue caps is that revenue caps are typically applied to subsets of the entire revenue requirement. None of the revenue caps in our sample index fuel costs. Fuel costs are handled with separate incentive mechanisms (SDG&E, SCE, ConEd), or FACs are retained (PG&E). SCE's revenue cap also excludes fixed generation costs. SDG&E breaks its revenue caps into three components: (1) labor O&M; (2) nonlabor, nonfuel O&M; and (3) capital additions to the electric network. The network capital additions formula has a different functional form and is discussed at the end of this section.

Table 3-3 shows how the four revenue indices in our sample handle customer growth, inflation, and productivity.

<u>Customer Growth</u>. Two of the revenue caps allow for a very simple adjustment where revenues are proportional to customer growth. We indicate this type of adjustment with the term *Average Revenue Per Customer* (ARPC). Such an adjustment is similar to the revenue decoupling method advocated by Moskovitz and Swofford (1992). SDG&E's O&M revenue indices are a fixed fraction (59%) of ARPC. SCE proposes a fixed per-customer adjustment of $773, which is 81 percent of SCE's ARPC.

In terms of inflation and productivity, three of the six equations shown use CPI and two use input price indices. ConEd's revenue formula has no explicit productivity or inflation adjustments. As with price caps, a wide range of productivity offsets are chosen. Productivity offsets are especially hard to compare for revenue indices because they differ in their comprehensiveness, which can affect underlying productivity, and productivity can be embedded in the CGA term. As an example of the latter complication, SDG&E's O&M indices require a 0.87 percent per year productivity adjustment, but they are allowed to

[22] PG&E's revenue cap applies to all nonfuel revenues except its large electric manufacturing class (LEMC), which would be regulated according to a price cap formula.

recover only 59 percent of their ARPC. In contrast, SCE takes on a 1.4 percent per year productivity offset but receives 81 percent of ARPC for customer growth. Productivity is being traded off between measures that are time-based (productivity offsets) and measures that are customer growth based (%ARPC in the CGA term).

Table 3-3. Inflation Indices and Productivity Offsets Used in Revenue Cap Plans

a. Revenue Cap

$$\overline{R}_t = (\overline{R}_{t-1} + CGA \times \Delta Cust) \times (1 + I - X)$$

Utility	Applicable Revenues (R)	Customer Growth Adjustment (CGA)	Inflation factor (I)	Productivity Offset (%/yr) (X)	Basis of Productivity Offset
SCE	All nongeneration revenues	$773 (Approx. 81% x ARPC)	CPI	1.4%	Analysis of past nongeneration TFP
ConEd	Most base-rate revenues broken down by customer class	ARPC	None explicit		N.A.
PG&E	Base-rate revenues excluding LEMC	ARPC	CPI	1.2%	Represents "high end" of empirical studies on utility productivity
SDG&E	Non-nuclear, nonlabor O&M	59% x APRC	Weighted average input price index	0.87%	Litigated value
SDG&E	Non-nuclear, labor O&M	59% x APRC	CPI	0.87%	Litigated value

b. Capital Additions Cap[†]

$$CA_t = CA_{t-1} \times (1 + I - X + \%CGA \times \frac{\Delta Cust}{Cust})$$

Utility	Capital Additions (CA)	% Customer Growth Adjustment (%CGA)	Inflation factor (I)	Productivity Offset (%/yr) (X)	Basis of Productivity Offset
SDG&E	Electrical network gross additions	24%[‡]	Handy-Whitman Index for Total Fossil Plant	(4.23%)	Regression of historical data

Notes: ARPC = Average Revenue Per Customer; CPI = Consumer Price Index, All Urban Consumers; LEMC = Large Electric Manufacturing Class; O&M = operations & maintenance (excluding fuel costs)

TFP= Total Factor Productivity

[†]The capital additions index is the primary component of a revenue requirement index that also includes return, depreciation, and tax components.

[‡]This is the net adjustment if customer growth is constant. See Volume II, Appendix A for complete formula.

The last equation in Table 3-3 is SDG&E's index for its electric network[23] capital additions; it has a different functional form from the other revenue caps. Instead of computing the revenue cap for network plant, it only computes allowed *additions* to net plant, which is an input to depreciation, return, and tax calculations that result in allowed revenues.[24] These additional calculations appear to be noncontroversial in SDG&E's case, so SDG&E is allowed to make them with minimal oversight. SDG&E's net plant formula contains coefficients based on a regression of historical, company-specific data. An interesting feature of the formula is that it allows for a 4.23 percent *increase* in annual network additions each year, above the rate of inflation. This adjustment may be considered equivalent to a *negative* 4.23 percent per year productivity offset. Tempering this negative productivity offset is that SDG&E is only allowed a 0.24 percent increase in net plant additions for every percent change in customer growth.[25]

We do not see anything inherently wrong with the use of multiple revenue requirement formulas as used by SDG&E compared to the broad, single formulas used by PG&E, SCE, and ConEd. As we argue in Chapter 2, however, multiple formulas are best shown together on a consistent basis, as we have done in Table 3-3. Once shown in this manner, one can easily see if the marginal incentive powers differ among revenue categories or if there are portions of operations completely excluded from the revenue cap.

3.3.3 Comparison of Historical Data with Utility Indices

To illustrate the differences among the productivity offsets and inflation indices shown in the previous section, we performed a simple backcast of four price cap plans and four revenue cap plans (Figure 3-1). These backcasts give an indication of how the mechanisms would have performed compared to historical inflation (CPI) and company-specific rate and revenue performance.[26] The figures shows the cumulative growth in these series for an eight-year period, 1984-1992. The revenue cap figures have been normalized to number of customers so that they could be compared more meaningfully to the change in the CPI. We make the following observations:

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[23] Electric network is defined to exclude additions for generation plant.

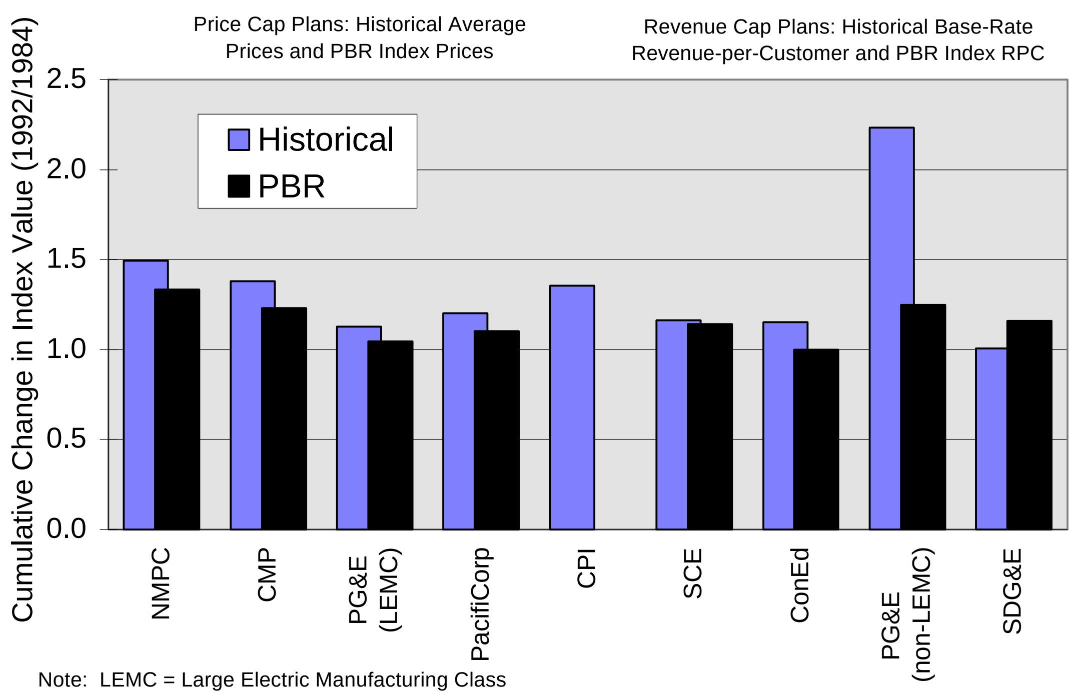
[24] SDG&E's PBR retains pre-PBR status quo where its cost of capital is adjusted annually in generic (multi-utility) rate cases.

[25] The number 0.24% is equal to 24% x 1%. The actual formula has terms for customer growth in both years t-1 and t-2. See Volume II, Appendix A for complete formula.

[26] For a description of how the backcasts were conducted, see Volume II, Appendix B.

- Over the historical period, the CPI rose by approximately a factor of 1.4. Compared to this price inflation and company-specific performance, the PBR indices would have generally controlled prices or revenues-per-customer better. The one exception is SDG&E's revenue cap, which beats the CPI but not its own historical revenue-per-customer performance.

Figure 3-1. Comparison of Historical Values to PBR Index Values: 1984-1992



Note: LEMC = Large Electric Manufacturing Class

- The price cap portion of Figure 3-1 (left-hand side) shows the importance of the choice of inflation index as well as the productivity offset. PG&E's index for its large manufacturing customers shows the lowest index growth even though PG&E proposed only a 0.5 percent year productivity offset (Table 3-2). Its index growth is lowest overall, however, because it depends on the PPI and that index grew by 1 percent per year during the historical period. In contrast the CPI grew at 3.8 percent per year (used by NMPC) and the IPD-GDP (used by CMP) grew by 3.6 percent per year.

- The revenue cap portion of Figure 3-1 (right-hand side) shows that ConEd's PBR mechanism controls bills the most and that PG&E's would have represented the biggest change from historical performance. PG&E had the largest historical growth in total bills (not shown) and the figure shows that it had, by far, the largest growth in base-rate revenues per customer. PG&E's large value is probably due to the cost of its Diablo Canyon nuclear power plant, which in addition to raising rates and bills, increased the portion of base-rate revenues relative to total revenues.

- San Diego's PBR performs worse than its own historical performance but with that result it should be kept in mind that it had the best historical performance of any of the utilities that we analyzed.

3.3.4 Treatment of Generation Fuel and Capacity Costs

A critical question about PBR is whether it can provide sufficient incentives for prudent capacity expansion. In this regard, our sample provides little guidance. Most, if not all, the utilities in our sample do not have large incremental generation capacity needs during the term of their PBR plans. Most of the PBR plans either do not address new capacity or, as in the case of SDG&E, specifically exclude it from their PBR.

More illuminating is the way the sample of PBR plans addresses existing generation and fuel costs. Existing generation costs are generally included in the PBRs of our sample. SCE's base-rate PBR explicitly excludes the capacity costs of existing generation but includes it in a proposed generation PBR (discussed below). With regard to fuel costs, most PBRs treat them differently from their primary PBR mechanism. This is because FACs are part of the status quo for most electric utilities considering PBR, and only three utilities appear willing to take on the increased risk that comes from eliminating their FACs. The following summarizes the PBRs' treatment of generation costs in more detail.

Price Caps

The five price cap mechanisms generally include existing generation capacity costs in their price cap but approach fuel costs in different ways.[27] With regard to fuel costs, PacifiCorp, CMP, and NYSEG completely eliminate their FACs. Although NMPC uses the same "CPI -X" index for both fuel and nonfuel costs, deviations between actual and indexed fuel costs are subject to a different sharing arrangement than nonfuel deviations. Sixty percent of all deviations between fuel costs and the CPI - X index are borne by ratepayers. Further, NMPC's fuel costs are subject to full pass-throughs whenever annual deviations (positive or negative) exceed $50 million. TEP's rate freeze also identifies a fuel and O&M sub cap of $0.058/kWh. TEP is at risk for all deviations above that amount and shares deviations below that amount equally with ratepayers.

[27] CMP partially excludes certain generation costs from purchased power contracts. Specifically, it has a separate provision for the buy-out or buy-down of above-market contracts. This mechanism allows some but not full pass-through of these stranded costs. See Volume II, Appendix A.

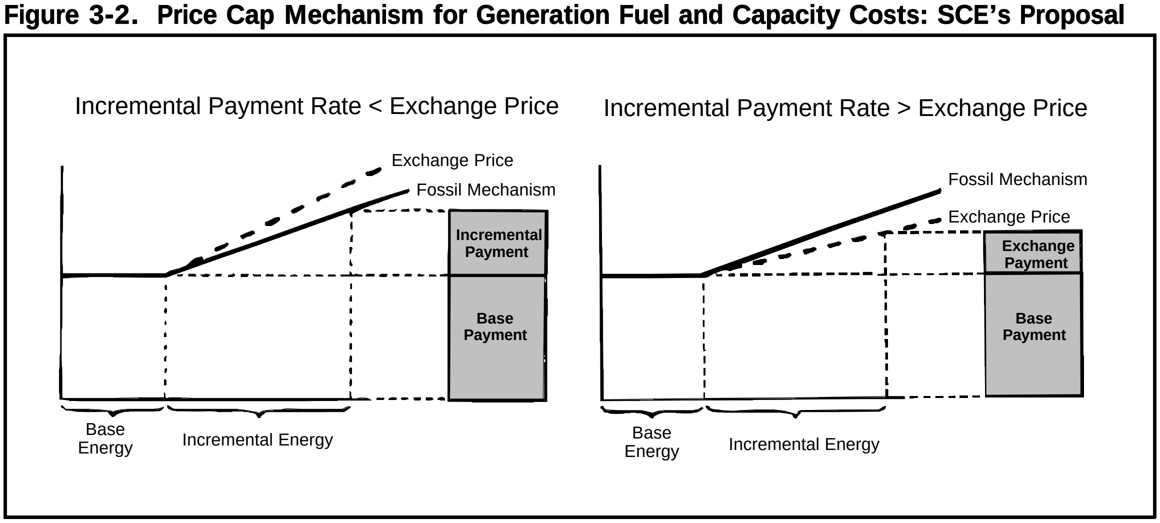
Revenue Caps

Revenue caps generally exclude fuel costs. This makes sense because a revenue cap assumes that a utility's costs are *not* proportional to sales, which is certainly wrong for fuel costs. Under revenue caps, fuel costs are either subject to a separate price cap mechanism or to status quo regulation. Separate fuel-cost price cap mechanisms have been proposed by SDG&E and SCE.

SDG&E's mechanism includes a formula for the estimation of a benchmark unit cost. Only a portion of SDG&E's fuel mix—purchased power and natural gas costs is indexed. All other fuel costs (QF, nuclear) are subject to full pass-throughs. Presumably reasonableness reviews are eliminated for costs subject to indexing.

SCE has filed a PBR proposal that covers its fossil fuel generation capacity and energy, separate from its T&D PBR. This proposal is a combination of a revenue cap and a price cap. The revenue cap allows SCE recovery of the fixed costs of its fossil generation system. For that amount of revenue, the utility is obligated to a minimum amount of generation. Above that minimum amount, SCE receives a fixed price based on a fixed heat-rate curve as well as indexed natural gas prices and emission offset costs. SCE would be bound to the revenues allowed by its generation price cap times the quantity of power generated. This constraint is shown as the "fossil mechanism" line in Figure 3-2. SCE, which expects to be participating in a new wholesale electric pool being developed in California, would also be bound to market prices if they are lower than its proposed generation price cap. As shown on the right hand side of Figure 3-2, SCE would be at risk if the market price of electricity (called "exchange price" in Figure 3-2) fell below the generation cap, for all revenues other than the base revenue. (For a description of the SCE mechanism, see Volume II, Appendix A.)

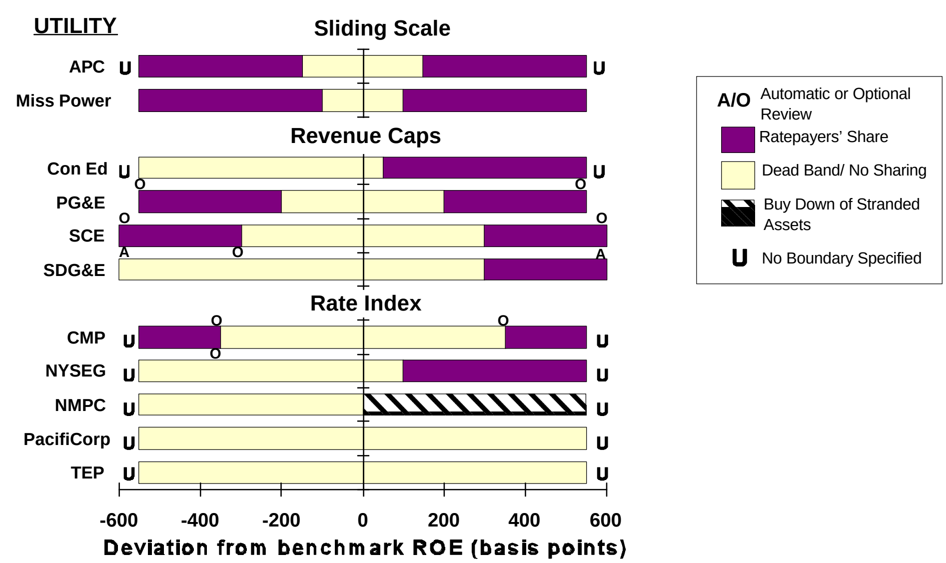
Figure 3-2. Price Cap Mechanism for Generation Fuel and Capacity Costs: SCE's Proposal



3.3.5 Earnings Sharing Mechanisms

Earnings sharing mechanisms track actual earnings, sharing with ratepayers any earnings that fall below or above certain thresholds. Excess or shortfall earnings accrue in a tracking account, and future rates adjust to amortize the balance in the account. Earnings sharing mechanisms are, in essence, sliding scale mechanisms. They may be the primary PBR mechanism, as in Mississippi and Alabama, or they may supplement a price or revenue cap plan as in seven of the nine price or revenue cap plans in our sample (Figure 3-3). In Figure 3-3, the light color means that the shareholders keep 75 percent or more of any earnings deviations. The dark color indicates that ratepayers keep more than 25 percent of any earnings deviations. Also shown in Figure 3-3 are automatic or optimal review triggers.

Figure 3-3. Comparison of PBR Earnings Sharing Mechanisms



Note: Miss Power, SCE, & SDG&E: Power mechanisms are specified in rate of return and have been converted to return on equity (ROE) assuming a debt-to-equity ratio = 1.0.

Earnings sharing mechanisms and earnings limits represent a departure from COS/ROR ratemaking which usually provides that utilities retain all deviations in earnings between rate cases. Despite their departure from tradition, earnings sharing mechanisms and review triggers appear quite popular. All of the revenue cap plans have explicit earnings sharing mechanisms and most have explicit review triggers. Three of the five price cap plans have earnings sharing mechanisms. NMPC's earnings sharing mechanism is unusual; only half of any earnings above the benchmark go to shareholders and the rest go to buy down "regulatory assets." Because these assets are potentially strandable, they may ultimately turn out to be a liability. It is unclear if they represent a liability to ratepayers or shareholders. Thus, we represent the upside sharing for NMPC with its own shading in Figure 3-3.

Except for NMPC's mechanism, all of the earnings sharing mechanisms have "deadbands" where shareholders are at risk for all or most earnings variations. Deadbands are at least 75 basis points wide, and some deadbands, like PG&E's, SCE's, SDG&E's, and CMP's are over 200 basis points wide.

As already noted, sliding scale plans are essentially little more than earnings sharing mechanisms. Figure 3-3 suppresses an important difference between the Alabama and Mississippi plans, however. For Alabama, the benchmark returns are set via COS/ROR methods. For Mississippi, the benchmark return is increased or decreased depending on how the company performs with respect to a multi-attribute performance index. Thus, while Mississippi's earnings are bounded relative to the benchmark, the benchmark is raised or lowered depending on performance.

As discussed in Chapter 2, the design of earnings sharing mechanisms has been controversial in regulatory proceedings. We identify that "standard" and "consumer-sharing" models of earnings sharing. All of the utilities in the sample, except NMPC's, have earnings sharing mechanisms that follow the standard model. (Recall that no explicit earnings sharing mechanism is also consistent with the standard model.) NMPC's earnings sharing mechanism is the exception because all upside earnings accrue towards the reduction in regulatory assets, rather than to the utility's current profits.

3.3.6 Z Factors

We define a "Z" factor as an adjustment to the price or revenue cap for an unforseen event. A Z factor should only cover costs that (1) are outside a utility management's control, and (2) have a disproportionate effect on a utility relative to the entire economy as tracked by the PBR index. We distinguish our definition of Z factors from more broad definitions that include costs of PBR exclusions, i.e., costs that continue to be regulated by COS/ROR. We also distinguish Z factors from the ratepayers' share of costs resulting from a targeted incentive or earnings sharing mechanism. Several utilities labeled such pass-throughs or ratepayer shares as Z factors. Even with our narrow definition, however, there is considerable variation in the definition of Z factors (Table 3-4). All but three of the nine price or revenue cap plans have identified some sort of Z factor; disproportionate changes in taxes or costs resulting from accounting rule changes, PUC regulations, or environmental regulations appear to be the factors most frequently identified.

Table 3-4. Off Ramps and Z Factors for Price and Revenue Cap Plans

Utility	Identified Z Factors	Minimum Threshold for Z Factors ($ Millions)	basis points (b.p.) ROE
CMP	• Mandated costs with "disproportionate effect on CMP and not accounted for in index" • 50% of transition costs to new accounting standards dealing with retirement benefits	$3	43 b.p.
ConEd	None	None	
NMPC	• Environmental and nuclear decommissioning costs • Legislative, regulatory, tax-law changes	None	
NYSEG	None	None	
PacifiCorp	• Changes in federal income taxes • Changes in energy related taxes	None	
PG&E	• Catastrophic events • "Extraordinary" costs	$50	54
SCE	• Major mandatory fee and tax changes • Major regulatory changes • Major claims or required modifications related to nuclear radiation or electromagnetic fields • Major accounting changes	$10	20
SDG&E	Open for application: • Local air control • Hazardous waste clean up • Factors beyond management's control	$ 0.5	3
TEP	• Unspecified "pro forma" adjustments	None	

Note: Z factors listed here only include costs that would otherwise be included within the scope of the index but are considered potentially extreme and beyond the control of management. Some utilities list other items, such as fuel cost adjustments, as Z factors.

It is logical that a Z factor should have a cost threshold, so that utilities can only seek relief when a Z-type cost change causes real economic harm. Despite this logic, only three of the six plans specify thresholds, and all are relatively small (3 to 54 basis points) when compared to thresholds associated with earnings sharing mechanisms.

Given the lack of uniformity among the plans, we believe that Z factors represent a potential liability for utilities and regulators. Although we would expect there to be some utility-to-utility variation in Z factors to reflect the specific conditions of each utility, the lack of uniformity indicates that all the contingent liabilities of PBR have not been consistently well thought out. Also, many PUCs will have to struggle with the issue of who as the burden of proof in determining price or revenue changes resulting from Z-factor requests. This issue will determine how much and what kind of litigation occurs. In general, we did not see in the plans adequate discussion of how Z factors will be adjudicated under PBR. A reasonable prediction based on Table 3-4 is that considerable learning and evolution is still to come on the topic of Z factors.

3.3.7 Supplemental Rate or Bill Incentives

A price or revenue cap directly caps the maximum rates or revenues collected from customers. Regardless of the rate or revenue setting process, however, it is also possible to tie earnings to rates or bills by adopting a supplemental incentive mechanism. We found supplemental mechanisms to be a part of Mississippi's sliding scale plan and a part of three of the revenue cap plans (Table 3-5).

Table 3-5. Supplemental Targeted Rate and Bill Index Incentives for Revenue Cap Plans

Utility	Customer Classes	Yardstick Measure	Maximum Incentive ($ Millions)	basis points (b.p.) ROE
Miss Power	All Customers	Weighted average retail price of electric utilities in the Southeastern Electric Exchange	+$4	100 b.p.
PG&E	Residential	National average bills	±$19	20
SCE	All Customers	An average of SCE's rates and bills as a percent of national average rates and bills	±$10	20
SDG&E	All Customers	National average rates, with SDG&E's comparison rate adjusted to a fixed level of DSM spending	±$10	69

Mississippi's rate index is a component of the multi-attribute index that affects its target earnings. Every half year, Mississippi computes its system average rate and this number is compared to the same average number of a peer group of Southeastern utilities. This latter number is typically known as the *yardstick* measure. In Mississippi's case, rate performance is one of three ways that its authorized (benchmark) return may be increased. The most that its authorized equity return can be enhanced due to superior rate performance is 100 basis points.

Three of the four revenue cap plans propose supplemental rate or bill incentive mechanisms (Table 3-5). SDG&E proposes a supplemental rate incentive, PG&E proposes a bill index for its residential class, and SCE proposes a combined supplemental rate and bill index. The rate incentives operate similar to Mississippi's. Bill indices are similar to rate indices but typical or average bills are used as the benchmark instead of rates.

A criticism of revenue cap PBR plans is that they ignore rate consequences. The creation of a supplemental rate index in the SCE and SDG&E plans may be thought of as a way to bring the consequences of rate increases into the overall incentive functions. Although Table 3-5 shows the yardstick, or basis of comparison for the rate or bill index, no explicit comparison of the relative power of these rate mechanisms compared to the primary revenue cap was made in the utilities' filings. We make a consistent comparison in our discussion of multiple incentives, Section 3.3.11.

SDG&E's rate incentive mechanism explicitly removes the effects of its DSM programs in the following manner. For purposes of computing the company's annual average rate for comparison to the national average, SDG&E adjusts rates assuming that DSM budgets are at their 1992 level. Thus, with respect to its rate incentive mechanism, SDG&E has no financial incentive to decrease its DSM budget and no financial disincentive to increase its budget.

There is a close relationship between revenue caps and bill indices. In the case of our sample utilities, the former caps total nonfuel revenues and the latter sets a benchmark that is equivalent to total revenues divided by total number of customers. Ignoring changes in fuel costs and assuming the number of customers is constant, percent changes in a company's revenues would exactly equal percent changes in its average bill. Thus, they are in many ways measuring the same thing. Given the similarities of the two measures, it is curious that SCE and PG&E have proposed bill indices to supplement their revenue caps. Because the mechanisms are partially redundant, it is possible that either utility could see its authorized revenues increase as a result of a decrease in costs. In other words, under combined revenue caps and supplemental bill incentives, it is possible for either utility to earn more than one dollar for every dollar saved.

3.3.8 Incentives for DSM

An important aspect of electricity regulation during the last ten years has been the use of incentives to encourage utilities to pursue cost-effective customer energy efficiency in their service territories. Regulatory incentives for demand-side management have been set up to address three general factors that discourage utilities from pursuing energy efficiency. First, regulation has addressed utilities' ability to recover the direct costs of DSM programs, including administrative costs. Second, regulations have assured that utilities recover net lost revenues when DSM programs decrease sales and avoided costs are below marginal revenues. Third, regulatory policies have been adopted to provide shareholder incentives *for* DSM by giving utilities a share of the net resource benefit of a DSM program or rewarding the utility for exemplary behavior (Eto et al. 1992). Most states have adopted policies that address the first disincentive (cost recovery), and different combinations of net lost revenue recovery mechanisms and shareholder incentives are widely used.

A critical issue is how these regulatory policies on DSM change under PBR. The best resolution of this issue depends in large part on one's view of competition and whether it is appropriate for an electric utility to pursue DSM in a competitive industry. Although a full analysis of that question is beyond the scope of this report, we can examine the three types of DSM incentive policies in our sample of utilities (Table 3-6).

DSM Cost Recovery

We first examined whether a utility's PBR plan included DSM program costs in its revenue or price index. Because the benefits of DSM are diffused among a large number of customers, it is difficult to measure a DSM program's benefits; in addition, the benefits of DSM can accrue over a long period. Both facts about DSM programs mean that a utility's budget could be subject to severe pressure if DSM were included in either a revenue or price index. Our sample of nine price and revenue cap plans is mixed; four of the nine PBR plans, CMP, ConEd, PG&E, and SDG&E, specifically exclude DSM budgets from the *indexed* portion of the PBR. SCE's index only partially includes the DSM budget; any underspending of the budget is not retained by shareholders, but is either held over for next year's DSM budget or is returned to ratepayers. SCE is at risk for any budget overruns. PG&E's revenue cap plan and all of the price cap plans incorporate DSM budgets into their indices. Thus these budgets will be subject to the same cost cutting incentives as any other part of the utility's operations subject to the rate or revenue cap. Given that the benefits of DSM are generally long term, inclusion of the DSM budgets in the capped rate or revenues may make them targets of cost cutting measures. However, targeted shareholder incentives still in force at PG&E, CMP, and TEP will somewhat mitigate this incentive to cut.

Table 3-6. Treatment of Utility DSM in Price and Revenue Cap Plans

Utility/ Price Cap Plans	DSM program costs in index mechanism?	Recovery of Lost Revenues	Supplemental Targeted Incentive for DSM
CMP	No	No	Shareholder Incentives (SI) retained
NMPC	Yes	Yes, NERAM (decoupling mechanism) eliminated, but DSM related-lost revenue adjustment added	SI eliminated
NYSEG	Yes	No (previous mechanism eliminated)	SI eliminated
PacifiCorp	Yes	ERAM eliminated	SI eliminated; performance targets adopted
TEP	Yes	No	SI retained
Utility/ Revenue Cap Plans			
ConEd	No	Yes	SI retained
PG&E	No	Yes (ERAM retained for all customers classes except LEMC)	SI retained
SCE	Partially (underspent budget held over or refunded to customers)	Yes (ERAM retained)	SI retained
SDG&E	No (special adjustment mechanism insulates DSM from rate incentives)	Yes (ERAM retained)	SI retained

Note: ERAM = Electric Revenue Adjustment Mechanism
NERAM = Niagara Mohawk Electric Revenue Adjustment Mechanism

Net Lost Revenues

A very important difference between price and revenue caps is how they treat net lost revenues from DSM programs. Price caps put the utility at risk for all net lost revenues, including net lost revenues from DSM programs. It is possible to add back lost revenues for *specific* DSM programs, but, in general, the utility is at risk for sales deviations. In contrast, revenue caps protect shareholders from revenue fluctuations resulting from sales variation because prices are adjusted every year for the latest sales forecast. The three California revenue cap plans go further and retain ERAM, which continuously accrues deviations between authorized and actual revenues and amortizes any balance at each rate revision. Thus, the four revenue caps may be considered to be either complete or near-complete sales decoupling mechanisms. At most, a utility is at risk for about one year's lost revenues for any change in sales. Because revenue caps protect a utility from most or all variations in margin resulting from sales changes, DSM advocates generally favor them over price caps.

Of the five price cap mechanisms, only NMPC addresses lost revenues. It proposes to include a mechanism, called DIRAM, which would add back revenues for specific utility DSM programs.

Shareholder Incentives

Both price and revenue cap plans can, in theory, retain shareholder incentives. These may be thought of targeted incentives for DSM. Six of the 11 plans retain shareholder incentives for DSM in some form, and three utilities (NMPC, NYSEG, and PacifiCorp) eliminate them. For utilities that retain shareholder incentives, an open question is how the shareholder incentive compares to the competing positive incentive of eliminating the program (under a revenue cap) or of increasing sales (under a price cap). Regulators should consider the combined impact of targeted incentives with the main incentive created by the price or revenue cap.

3.3.9 Supplemental Service Quality Incentives

There are legitimate concerns that service quality will suffer when PBR increases a utility's financial incentive for cutting costs. Some plans have supplemented their primary index mechanism with a mechanism that defines a dollar incentive (or penalty) for increased (or decreased) reliability or customer satisfaction.

All but three of the PBR plans in our sample have explicit service quality incentive mechanisms (Table 3-7). All of the revenue cap plans and the NMPC, NYSEG, and CMP rate cap plans have such mechanisms. The Mississippi Power plan has a customer satisfaction attribute in its sliding scale mechanism as well.

As shown in Table 3-7, service quality benchmarks are constructed in various ways. All of the mechanisms include the use of customer surveys. All of the plans gauge performance by comparing a particular plan year to a past year. In addition, NMPC proposes to compare itself to a peer group of utilities using an already existing survey. Comparison to a peer group as a benchmark is preferable to the use of past performance because the latter is more susceptible to ratcheting.[28]

[28] The ratchet effect occurs when a utility benchmark is set based on past performance. If a utility improves its performance in one period, attaining its incentive in the next period becomes all the more difficult because the performance standard will be raised. The net effect is to dilute the incentive of improving performance in the current period.

Table 3-7. Electric Service Quality Index Incentive Mechanisms

Features	Utility							
	CMP	ConEd	Miss Power	NYSEG	NMPC	PG&E	SCE	SDG&E
Total numbers of indicators used in Service Quality Index	5	14	2	10	7	4	2	3
Maximum Annual Incentive Payment (basis points ROE)	-42‡	±15	+100	+15/-25	-21‡	±41	-20†‡	+62/-76†
Service Quality Index includes:								
Customer survey(s) [U-comparison to history; P-comparison to peer group]	U	U	U	U	U, P	U	U	U
PUC complaint rate	X	X		X	X			
Time to respond to telephone calls or letters		X		X				
Meter reading/billing accuracy		X						
Minutes of interruption	X	X	X	X	X	X	X	X
Customer outreach & education				X				
Employee safety								X

Notes: PG&E, SDG&E, and NMPC's service quality indices include measures that are affected by performance in both the electric and gas departments.

† Maximum incentive for company is set in terms of dollars per year. This maximum incentive is converted to basis points using recent estimates of company net plant and an assumed debt-to-equity ratio of 1.0.

‡ Penalty only.

The next most common measure used in these mechanisms is some measure of distribution-level outages. In addition to customer surveys and outage time, a variety of other measures are used as is indicated in the table.

3.3.10 Pricing Flexibility

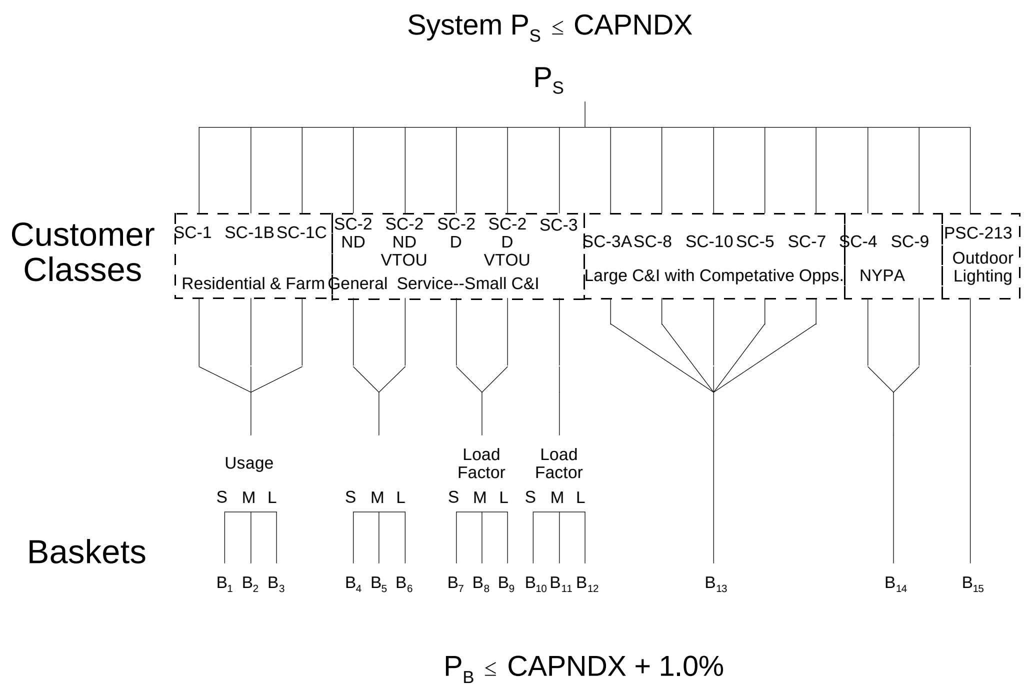
One of the potential benefits of PBR is that it constrains monopoly power while allowing a utility flexibility to respond to competitors' prices. Revenue cap plans cannot address pricing flexibility directly; the cap, by definition, only determines revenues. Some other method, usually traditional litigated proceedings, is necessary to allocate costs to customer classes and set specific tariffs. As discussed in Chapter 4, this limitation on revenue caps is a good thing, because if a utility were free to set prices under a revenue cap, the incentives would likely lead to undesirable outcomes.

Price caps, as the name implies, set the upper bound, but utilities may be allowed to price flexibly below the cap. Of the six price cap mechanisms in our sample, four explicitly allow pricing flexibility: NMPC; CMP; TEP; and PG&E's cap for its industrial customers. Regulators and utilities implementing pricing flexibility must balance two competing goals: they want to allow a utility to respond to competition, but they also want to protect customers who have few or no alternatives. A price cap that controls average prices may be unsatisfactory if the low rate given to one customer is offset by higher rates given to another. One way to allow for pricing flexibility is to use the concept of market baskets. Market baskets are groups of customers or services. Within a market basket, a utility has complete pricing flexibility—it can charge whatever it wants so long as the average price for the basket is at or below the basket's cap. Customers with few alternatives are put in the same basket, and thus are protected from subsidizing discounts offered to customers in other baskets.

NMPC's proposal uses the "market basket" concept for pricing flexibility (Figure 3-4). Under NMPC's plan, each basket must stay within 101 percent of its price cap (CAPNDX) and, on average, all baskets must be below the cap. Within each cap, considerable pricing flexibility is allowed. An interesting aspect of NMPC's proposal is that it defined the baskets as both sub- and supersets of existing customer classes. One does not need to be bound to traditional customer designations when defining the baskets. For example, by using load factors as the defining criterion for baskets B_7 through B_{12}, NMPC is limiting its ability to raise customer or demand charges in any basket.

Another approach to pricing flexibility is alternative tariffs. The four plans that propose pricing flexibility allow alternative tariffs or special contracts. In these situations, the standard tariff is subject to the cap and cap index, if any. These tariffs represent de facto just and reasonable rates. The utility and the customer are free to negotiate alternative rates.

Figure 3-4. Relationship of NMPC's Overall Index (CAPNDX), System Average Price (P_S), Basket Price (P_B), and Existing Customer Classes



Source: Adapted from NMPC

3.3.11 Coordination of Multiple Incentives

In Chapter 2, we identified the possible distortions that come from multiple incentives with different marginal sharing rates and the ambiguity created by multiple incentives that are not presented in any coordinated manner. Based on our review, we conclude the sample plans do a poor job of showing how multiple incentive mechanisms are coordinated. NMPC, SDG&E, TEP, ConEd, and PG&E all have plans that have marginal incentive powers that are lower on fuel costs than on base-rate expenses. All of the revenue cap mechanisms propose supplemental bill and/or rate incentives as well as service quality incentive mechanisms. NMPC and CMP have seemingly straightforward rate caps, but they too have different incentive mechanisms for service quality (both), QF costs (CMP), and fuel costs (NMPC). The coordination of these multiple incentives is less than fully transparent.

Simply showing the relationship of multiple incentives can provide important illumination, even if it requires simplification of the specific mechanisms. For example, SDG&E's base rate revenue cap and rate performance incentive may be stated as follows:

$$R_t \leq \bar{R}_t\left(1 + \frac{0.14(\bar{P}_t - P_t)}{\bar{P}_t}\right) \qquad \textbf{(3-3)}$$

where,

R_t	=	revenues at time t
$\bar{R}_t$	=	nominal revenue cap at time t
P_t	=	average price at time t
$\bar{P}_t$	=	price "target" at time t, set at 137 to 132% of the national average rate, depending on the year[29]

The equation shows that SDG&E's rate performance can ultimately affect its base rate revenue cap and that the marginal relationship between the rate and revenue cap is about 14 percent.[30] We call the revenue cap "nominal" because, ultimately, the total allowed revenues allowed to the company is the total of its revenue cap in any year *plus* the rate performance incentive award. The right hand side of the equation, thus, more accurately portrays the utility's true revenue cap and with that equation we make several observations. First, the equation clearly shows that rates do matter for SDG&E. One strategy of SDG&E under a rate cap is not to lower its unit costs but to try to constrain output to lower total costs. If SDG&E succeeds at this, it will increase its profits relative to the nominal cap but it will increase its rates. In such a situation, SDG&E is hit with a penalty, because its overall revenue cap is lowered by 0.14 times the percentage change in rates. For example, the overall revenue cap would be decreased by 1.4 percent if rates were increased ten percent. Thus, SDG&E has an incentive to lower rates rather than raise them as a way of meeting its revenue targets. Demand elasticities add an important complication to the problem, however, because a 1 percent reduction in rates will increase demand somewhat, thus making it harder

29 In some years, the target rate also contains a deadband. No incentives (penalties) are awarded unless the utility's rate falls below (above) the target minus (plus) the deadband. We ignore the deadband in this example.

30 The marginal rate of 14% may be computed as follows. The rate performance incentive mechanism offers $2 million per percentage point change in system average rates relative to the target rate. SDG&E's retail revenues are $1,409 million/year. One percent of annual revenues is $14 million. Thus the ratio of incentives from a 1% change in rates to a 1% change in costs is 2/14 or 14%. We also ignore fuel costs in this example for simplicity.

for SDG&E to meet its revenue target.[31] As it turns out, the marginal relationship between the rate and revenue cap is crucial for deciding whether SDG&E has an incentive to meet its revenue cap by trying to lower costs or constrain demand. The proper relationship greatly depends on the elasticity for demand. We discuss this issue for a generic utility in Chapter 4.

3.3.12 Summary Assessment of Incentive Power: The LBNL Power Index

The discussion in this chapter gives a sense of how different utilities addressed specific design issues in their PBR plan. It is difficult, however, to understand how the PBR plans compare to each other or to status quo regulation without PBR. In Chapter 1, we defined incentive power as the degree to which revenues received are geared to external rather than utility-specific measures of cost. High-powered incentive mechanisms put a utility at a high degree of risk for incremental changes in margin; low-powered mechanisms protect the utility with pass-throughs of costs. To reflect the overall power of each of the proposed plans, we developed the following index:

$$POWERNDX = \sum_{i}^{N} f_i \ x \ b_i \ x \ T_i \qquad \textbf{(3-4)}$$

here,

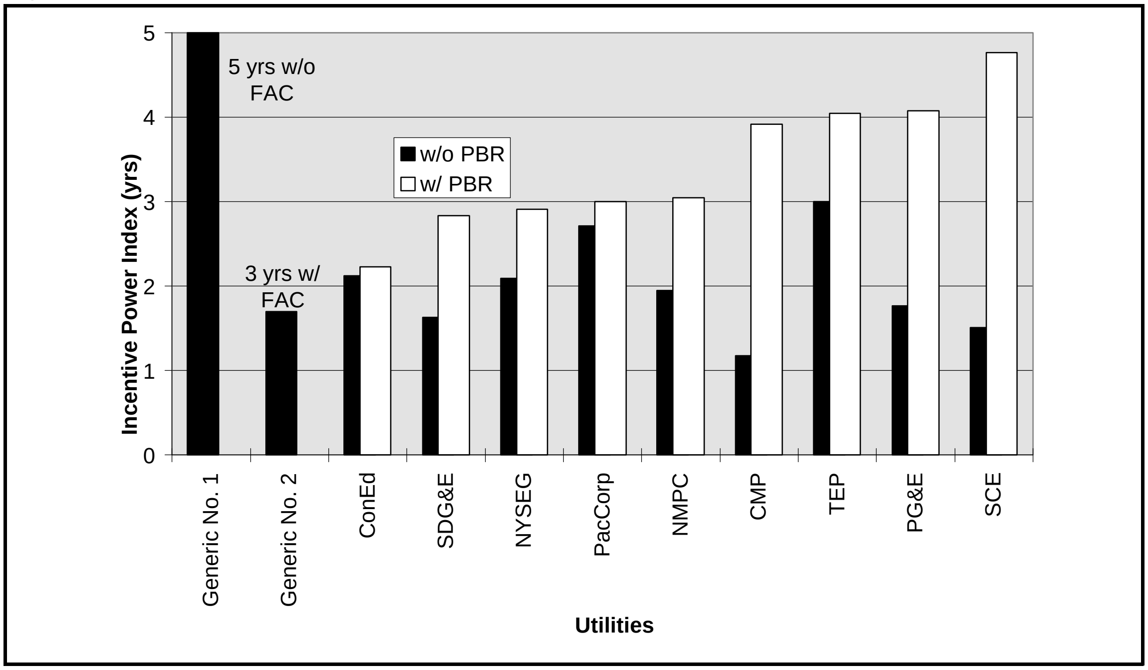
POWERNDX	=	LBNL power index (years at 100% incentive power)
b_i	=	shareholder incentive power of revenue category *i* (percent)
f_i	=	category *i* revenues as a percent of total revenue requirement
T_i	=	term of incentive mechanism applicable to category *i*

Using EIA data on each of the sample utilities (1995), we broke down each utility's revenues into major categories: nonfuel O&M, depreciation, fuel, taxes, interest, and return on equity.[32] We then assigned an incentive power and term to each revenue component based on our research on PBR plans. The resulting index values, which may be considered a reasonable, albeit approximate, measure of the total incentive power of each plan are shown

31 A demand elasticity is the percent change in demand divided by the percent change in price. It is usually expressed as a ratio. In the case of SDG&E, if a 1% price decrease causes more than a 14% increase in demand (implying an elasticity lower than -0.14), the revenues collected by the company will increase by more than 14% thus canceling out the reward of increasing the revenue cap.

32 We also separated fuel costs into three subgroups: hydro and fossil, nuclear, and purchased power (including QF power).

Figure 3-5. LBNL Index of Incentive Power



for each utility, both with and without PBR, in Figure 3-5.[33] The units of the index are in years at an incentive power of 100 percent. Its value is roughly proportional to the total value of profit opportunities available to the utility under the PBR.[34] Our index looks primarily at resource efficiency; i.e., the incentive for a utility to decrease costs. Because of this, the LBNL power index does not differentiate between price and revenue caps. As will be explained further in Chapter 4, we believe that both revenue and price caps have the same resource efficiency properties. Further, the index does not consider equity issues; i.e., who receives the benefit of the productivity improvement—consumers, shareholders, or other parties. Those issues are addressed by rate or revenue indices or by cost allocation and pricing flexibility policies. None of these factors are incorporated into the index.

For comparison purposes, we also show the incentive power for situations that we believe represent the two typical ends of the U.S. regulatory spectrum: a generic utility that has (1) no FAC and infrequent rate cases—one every five years; and (2) base rate cases every three

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[33] Calculations for index values for each company are contained in Volume II, Appendix B.

[34] A PBR with a three-year term and an index value of 3.0, for example, would indicate that if the utility could reduce its total costs (including its cost of capital) by $1/year for three years, it would increase its (undiscounted) profits by $3. We ignored discounting for simplicity. To compare values of the index across utilities, one must assume that the cost-reducing opportunities for each utility are the same.

years but has full pass-through of fuel costs through a fuel adjustment clause (FAC).[35] For our generic utilities, we used 1993 weighted-average revenues for all U.S. investor-owned utilities. The index values for our generic utilities illustrate the relative importance of term and incentive power in our index. Generic Utility No. 1 has an index value of 5: incentive power is 100 percent and the term is 5 years (100% x 5 = 5). Although Generic Utility No. 2 has rate cases every three years, its index value is not three because its annual power is less than 100 percent due to its FAC.

The LBNL incentive power index tells us the following:

- Incentive power varies widely in the sample, but most plans represent an improvement over the utility's status quo and represent an improvement compared to Generic Utility No. 1. Ratemaking in the U.S. still has a political dimension and a legal standard of "just and reasonable" so it is no surprise that terms never exceed eight years. This limited commitment clearly restricts the power of any of these PBR plans.

- The highest-powered plan that has been implemented is CMP's. Its high score comes from its broad deadband in its earnings sharing mechanism, which results in a high marginal incentive power, and from its comprehensive scope and five-year term.

- SCE's, PG&E's, and TEP's plans have the highest with-PBR scores but it should be reemphasized that their plans are still in the proposal stage. SCE's and PG&E's treat nonutility power purchases as pass-throughs, and PG&E has proposed no incentive mechanism for its fossil plants.[36] Both utilities, however, have targeted performance-based incentives on their nuclear costs and they both have long terms: PG&E's plan has a six-year term and SCE's plan is six years for base-rate revenues and eight years for fossil costs. PG&E's and SCE's PBR plans are not simple; they have multiple indices and/or supplemental targeted incentives. It appears, however, that the complications of these plans allow for the utility to commit to a long term. Complicated indices are certainly not required, however. TEP's plan—basically a rate freeze—also scores high. TEP's term is for five years, and except for limited cost sharing on certain fuel and nonfuel O&M costs, there would be no FAC under TEP's plan.

- Two plans that are generally considered novel and broad do not score as well as

35 We acknowledge that FACs are not without any incentive power. For FACs without continual adjustments, we assign one year's regulatory lag. Further, most utilities face some reasonableness review risk as a result of FAC proceedings. We assume this risk is zero.

36 For both SCE and PG&E, we include the incentive power (in both the with- and without-PBR cases) to include targeted incentive plans for their largest nuclear power plants.

might be expected. First, although SDG&E's has a five-year term and is broad in scope, its index power suffers because it has many cost pass-throughs: changes in power plant efficiencies, nonutility purchases, and cost-of-capital are all subject to non-PBR regulations. SDG&E recently noted that it was able to lower costs by aggressive refinancing of debt (Schavrin 1995). Ironically, under its PBR, it will be able to capture few of those savings.[37] Second, NMPC's proposal, although it consists of a comprehensive price cap, has a proposed term of only four years, retains a partial FAC, and shares above-benchmark earnings with ratepayers. Earnings in excess of benchmark returns are applied to "regulatory assets." Lacking any information on who would benefit from such a buy-down, we assume that the buy-down of these assets benefits ratepayers and shareholders equally.

- Turning from absolute levels of index values to relative "without-to-with" changes, CMP, PG&E, and SCE score the highest. SDG&E and NMPC also score relatively high. Thus, despite their low absolute scores, they score above average *gains*. On the down side, two plans show little improvement in comparison to the "without-PBR" case. ConEd's plan appears not very different from its previous COS/ROR rate case plans, and the same goes for PacifiCorp. PacifiCorp eliminated its FAC several years ago and its PBR term is only three years, so the with-PBR index shows only a small increase.

One of the criticisms leveled on PBR is that is a complicated way of doing something that PUCs have been good at for a long time: setting rates and leaving them fixed for extended periods of time. The LBNL power index clearly shows that there is some truth to this. Generic Utility No. 1 beats all the PBR plans, even ones that have portions committing to 6 and 8 years. Whether a PBR represents an improvement over the status quo first requires an examination of the status quo. Some states will find that business-as-usual regulation is quite powerful. Others will find that COS/ROR with little regulatory lag is the norm and PBR can improve the incentive for the utility to be resource efficient.

[37] Schavrin (1995). Under the status quo, SDG&E is subject to an annual cost of capital proceeding. SDG&E is pursuing a proposal to index its cost of capital, but we do not include it here.

CHAPTER 4

Revenue Caps: Implications for DSM

4.1 Overview

This chapter analyzes the incentive effects of revenue-cap PBR mechanisms. The importance of this task derives both from the common occurrence of revenue caps among the newly implemented electric industry PBR mechanisms, and from the fact that the revenue cap mechanism has been explicitly proposed as a replacement for the theoretically favored price cap mechanism. This proposed replacement is based on the perception that price caps provide a strong disincentive to utility investment in energy efficiency[38] and has been made explicitly by Moskovitz (1992), and by Marcus and Grueneich (1994, pp. 41-42), and has been hinted at by Hamrin et al. (1994, p. 150). Revenue caps are currently in use at ConEd and SDG&E, and have been proposed for PG&E and SCE.

It is also important to note what this chapter is not attempting to accomplish. We will be interested on the incentive implications for energy efficiency of price and revenue caps, but we will not attempt answer the question of whether energy efficiency is or should be an agreed objective of state utility policy. We will also not consider the effect of other possible incentive mechanisms on DSM. This chapter focuses solely on the incentives of revenue caps and how they compare with price caps. We will also not be concerned with predicting outcomes of the discovered incentives. When we find that a utility has an incentive of V¢ per unit of increase in X, we have solved half the problem of determining how much X will be increased. To finish the problem one must discover and utilize the cost function for increasing X; this is an entirely separate subject which we will not address. Finally, this chapter is not addressed to academic economists, though we believe that some of the ideas in this chapter are new and of interest to that community.

In this chapter we confirm that price caps, coupled with the current pricing structure, create a disincentive to effective energy efficiency programs, and that revenue caps do reverse this disincentive. We also confirm that revenue caps produce exactly the same cost minimizing incentives as do price caps, and that utilities are no more sensitive to growth in customer base with a revenue-per-customer cap than with a price cap.

A recent and *potentially* devastating critique of revenue caps has been put forward by economists Crew and Kleindorfer (Crew and Kleindorfer 1995). Their critique purports to show that a revenue-capped firm will always set price *above* the monopoly level. While we acknowledge the possibility of this effect, especially if a firm can engage in successful

[38] The California PUC, Division of Strategic Planning states: “The price cap model ... provides a strong disincentive to invest in energy efficiency.” (CPUC 1993b, p. 175).

DSM,[39] we show several ways in which this pricing effect can be inhibited. First, under some circumstances, the Crew-Kleindorfer effect can be inhibited by a price cap used in conjunction with a revenue cap without reversing the revenue cap's DSM incentives. Second, inelastic short-run demand may inhibit the effect. Third, we propose a new hybrid price-revenue cap as the safest way to avoid the Crew-Kleindorfer effect and related price effects.

Lastly we discuss the subtle problem of relative prices. It is well known that price caps, by allowing flexibility in the price of one product or of one class relative to another, will induce the utility to approximate Ramsey pricing.[40] Revenue caps, on the other hand, are shown to motivate large relative price changes in the opposite direction to those of Ramsey pricing. This effect of revenue caps could cause even larger pricing inefficiencies than the Crew-Kleindorfer effect, and should be inhibited either by explicit regulation of relative prices or by the adoption of a hybrid cap that leans towards the price-cap end of the spectrum.

In summary, our analysis of pure revenue caps reveals a number of potential problems:

(1) Incentives to set relative prices inefficiently.

(2) The possibility that a small reduction in the revenue cap will produce a large and unpredictable reduction in price (an effect related to the Crew-Kleindorfer effect).

(3) An incentive to reduce sales regardless of the social benefit.

For those who are concerned with the sales incentives of price caps we recommend, in place of the pure revenue cap, a hybrid price-revenue cap. We also recommend that this be employed in a revenue-per-customer form. Such a cap would only need to replace the energy part of a price cap, and could take a form as simple as the following.

$$P_E < \bar{P}_E - \frac{R_E}{q_0 \cdot N} \qquad \textbf{(1)}$$

P_E is the price of energy, $\bar{P}_E$ is like a price cap only high enough to compensate for the following revenue term. The subtracted term measures revenue from energy charges divided by initial energy per customer times the number of customers.

This hybrid cap will (1) greatly reduce the incentive to distort relative prices, (2) prevent the uncertain price response caused by a pure revenue cap, and (3) remove the anti-DSM bias of a price cap without causing an incentive to reduce sales without regard to social benefit.

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[39] For convenience we will often refer to energy efficiency programs simply as DSM (demand-side management) even though the meaning of this term is significantly broader.

[40] This was shown by Vogelsang and Finsinger (1979). Ramsey pricing marks up prices in inverse proportion to a product's demand elasticity. Thus the price of access, being inelastically demanded, would be marked up more than average. Theoretically, this scheme maximizes consumer welfare.

The most significant question left unanswered by this chapter is the question of exactly what relative pricing incentive will remain under such a hybrid cap.

4.2 Background

Because price-caps encourage the minimization of *average* cost, they may also encourage the maximization of sales in order to dilute fixed costs.[41] Unfortunately this behavior often runs counter to the encouragement of energy efficiency which regulators have often promoted. As a remedy, revenue caps have been proposed as a replacement for price caps.

Revenue-cap regulation, in its simplest form, simply limits to a predetermined level the amount of revenue per year that a firm can collect from its customer base. As a consequence the utility has a clear incentive to encourage minimal total demand, and thus minimal demand per customer.[42] One way to do this is to encourage the efficient use of power, but this is not the only way, and there are many complications. Nonetheless, with proper adjustment, and in the right circumstances, a revenue cap might motivate both supply-side cost minimization and demand-side efficiency maximization without imposing too much risk or inducing perverse behavior on the part of the utility.

Revenue-cap regulation is not without precedent. Just as standard ROR regulation is actually a type of price-cap regulation, ROR with an electric revenue adjustment mechanism (ERAM) is actually a type of revenue-cap regulation. With an ERAM in place, a utility is guaranteed a fixed revenue in place of a fixed price. (Revenue is usually not completely fixed but is made temporarily independent of costs.) Another approach that has been much discussed and is essentially equivalent to revenue-cap regulation is the external bill index, or revenue-per-customer PBR. Because customer bills are in total equal to a utility's revenue, rewarding a utility for bill reductions provides incentives that are essentially similar to those of revenue-cap regulation.

The central assumption behind the advocacy of revenue-cap regulation is that the utility *can* affect the demand-curve for energy. This assumption is not usually made in the economic

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[41] The existence of fixed costs, causes average cost to decline as production increases. For this reason most firms constantly seek to increase sales. Typically this is done by advertising for new customers and for greater use per customer. Although distribution companies cannot control their customer base, they can, and have been know to, seek to influence their per-customer demand.

[42] Of course the costliness of this encouragement may make it uneconomical, but our first task is to measure the strength of the encouragement.

analysis of price-cap regulation.[43] This may be why the standard economics literature ignores revenue caps.

Those concerned with energy efficiency point to discrepancies between marginal costs and prices, and to the possibility that utilities can significantly influence demand through DSM programs. If these assumptions are correct, then they need to be accounted for in the analysis of regulatory incentives. Consequently, our analysis first attempts to construct a framework for analyzing the relationships among price structures, cost functions and regulatory mechanisms.[44]

4.3 Modeling Industry Costs and Prices and Regulatory Mechanisms

To analyze price and revenue caps, we need to specify the structure of a utility's costs and prices. Clearly both of these structures are extremely complex, so we use a simplified model that captures the most essential features (more than could be captured by a nonmathematical treatment of this subject). With the necessary simplifying assumptions, we write utility costs as:

$$C = a + bN + cE + dL \qquad \textbf{(2)}$$

where,	N	=	Number of customers
	E	=	Total energy
	L	=	Peak load

Later, when it is needed, we will introduce the concept that both E and L depend on N. This in no way contradicts Equation 4-1, but it does require us to remember that the effect shown by Equation 4-1 of changing N is the effect with E and L held constant. This affect has economic significance but it is not the one we are ultimately most interested in.[45] Also note

43 Although economists do at times consider the possibility of the firm shifting its own demand curve (Lewis and Sappington 1992) (Laffont and Tirole 1993, Chapter 4), there has been little if any academic analysis of price caps from this point of view.

44 One clarification of revenue caps may be needed. Price-cap literature often addresses the problem of capping prices at a multi product firm. An aggregate cap is usually suggested rather than a cap for each individual price. This allows a firm relative-price flexibility, which can improve efficiency. Such an aggregate cap involves a quantity-weighted average of prices that looks similar to a revenue calculation. The difference is that it uses past quantities instead of present quantities as weights. This section is not concerned with average-price caps.

45 This linear approximation is fairly good because the inputs required to support customers (poles and billing), the inputs associated strictly with energy (fuels), and the inputs associated strictly with peak load (wires and generators) do not interact strongly. That is, if you double peak load and leave energy and customers fixed, fuel use is not changed dramatically, and billing costs don't change at all.

that since our results are differential in nature, nothing would be gained by replacing a local linear approximation by the true cost function (i.e., nothing we say depends on second derivatives.)

The price structure, which is modeled by specifying the revenue equation, has a very similar form:

$$R = P_N N + P_E E + P_L L \tag{3}$$

where,	R	=	Revenue
	P_N	=	Access charge
	P_E	=	Energy charge
	P_L	=	Demand charge

Prices essentially consist of a hookup or access charge, which will be denoted by P_N, by an energy charge, P_E , and by a demand charge, P_L.[46] Distinguishing these components of price is crucial, as is recognized by NMPC in the following statement.

> "... the internal price indexes have separate categories for access, demand, and volumetric charges. Accordingly the Company can, via rate redesign, change the relative importance of these charges and still hold its internal indexes constant." (Lowry 1994, p.7)

Finally, we specify the structure of the two alternative incentive mechanisms: price cap, and revenue cap.

$$\begin{aligned} \text{Price Cap:} \quad & P_N < \bar{P}_N \;, \quad P_E < \bar{P}_E \quad \text{and} \quad P_L < \bar{P}_L \\ \text{Revenue Cap:} \quad & R < \bar{R} \end{aligned} \tag{4}$$

Notice that this is an inflexible price cap, which is simpler than the cap on a Laspeyer's price index that is often used in practice.[47] The inflexible mechanism, which caps P_N , P_E , and P_L separately, differs from its more flexible cousins only in that flexibility allows the utility to choose the relative values of its prices. The implications of this choice will be examined in Section 4.9.

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[46] For the utility as a whole, P_L is far from constant, but within customer classes this model is reasonable. Still, it ignores the fact that the peak loads of individual customers are not coincident with the utility's peak. This could be largely corrected with a proportionality factor. In spite of these deficiencies, the model serves its purpose.

[47] The most common form of price cap, used by NMPC among others, is a cap on a Laspeyer's index of price. This index is formed by taking a weighted average of prices with the weightings based on past quantities.

4.4 Incentives of Price and Revenue Caps

Incentive mechanisms are designed to induce a firm to optimize its behavior. But the ways in which this optimization is done may be difficult for a regulator to observe and control. Typically, a firm will minimize costs, which in our model corresponds to minimizing the cost parameters *a, b, c,* and *d* of Equation 4-2. In the current context, we are also interested in the utility's incentive to modify several variables that are not normally considered to be under its control, namely, *N, E* and *L*. In particular, we are looking for incentives for the utility to reduce *E/N*, energy use per customer, which we will call *q*.

Finding these PBR incentives is now simply a matter of differentiating profit with respect to the utility's cost parameters and with respect to the customer variables over which it may have control. Profit is given by $\pi = R - C$, and we assume that the regulatory caps are binding constraints. This allows us to compute profit.

$$\begin{aligned} \text{Price Cap:} \quad \pi &= -a + (P_N - b)N + (P_E - c)E + (P_L - d)L \approx 0 \\ \text{Revenue Cap:} \quad \pi &= \bar{R} - (a + bN + cE + dL) \approx 0 \end{aligned} \tag{5}$$

First consider the cost parameters *a, b, c,* and *d*. Under either a price or revenue cap, a utility will have a clear and strong incentive to minimize all cost parameters, as can be seen in Equation 4-5 where all of them make negative contributions to profit. These incentives are exactly the same for either mechanism.

Next, consider the customer variables under a *revenue cap*. The profit equations clearly show that a utility has an incentive to reduce *E*, and *L*, and that these incentives are equal to the marginal cost of each of these variables. (*N* will be considered shortly.) Thus the incentives are quite substantial. Because a reduction in *q* (energy use per customer) will reduce E, the utility will have a strong incentive to reduce *q*, which is our goal. (Note that just because a firm has an incentive to reduce *q*, it may not choose to do so if it finds it too costly; i.e. cost provides a conflicting incentive. At this time we do not wish to analyze the net incentive.)

Finally consider the customer variables *E* and *L* under a *price cap*. The incentives of the price cap are more ambiguous than those of the revenue cap, depending on the relative values of the various price and cost components, so we now consider how P_E compares to *c* and how P_L compares to *d*. Because there is no transfer payment to the utility corresponding to the fixed cost, *a*, at least one of the three prices must be higher than its corresponding costs. Fixed cost, *a*, will be small in a utility that has been run as if it were in a competitive market, but will be large for utilities that have what may become large "stranded assets."[48] We will

[48] For a single generation facility the fixed cost may be significant, but a utility does not generate at a single plant. For a utility, capacity is expanded by adding new units. As long as the cost of new units is similar to the cost

consider an intermediate case. Incentive problems are typically caused by misalignment between various marginal costs and prices. Specifically, P_L is typically set to zero for residential customers and the cost of capacity is shifted to the price of energy, inducing $P_E > c$. This gives the utility a strong incentive to minimize L and a strong incentive to maximize E (to the extent that this can be done without increasing L proportionally). A second pricing bias that is perceived to be widespread is the underpricing of access.[49] This shifts costs onto the energy price component, further increasing the incentive to maximize E. However, the incentive to minimize N is not as great as it would at first appear, because N plays a role in determining both E and L.[50] This effect is best seen by rewriting the profit equations as follows:

$$\begin{aligned} \text{Price Cap:} \quad & \pi = -a + [(P_N - b) + (P_E - c)q + (P_L - d)k]\,N \approx 0 \\ \text{Revenue Cap:} \quad & \pi = \bar{R} - a - (b + cq + dk)\,N \approx 0 \end{aligned} \qquad \textbf{(6)}$$

As before, q is energy use per customer, and k is now peak load per customer, so $qN = E$, and $kN = L$.

We are first interested in the incentive to maximize N, which can now be found by differentiating either equation in (4-6) by N, and then using the approximation that economic profit is zero.[51] For a price cap $d\pi/dN = [(P_N \ldots)k]$, the value of which is easily solved for from the approximating equation $\pi = 0$. One step of algebra shows that $[(P_N \ldots)k] = a/N$, so $d\pi/dN$ is approximately a/N. Similarly we find that for a revenue cap $d\pi/dN$ is approximately $(a-\bar{R})/N$. Our best estimate is that a is much smaller than R, so the incentive is to *decrease N* under a revenue cap.

In our first round of analysis of price and revenue caps, we have learned that the two mechanisms work equally well to induce reductions in cost parameters. We have also confirmed that pure price caps discourage DSM while pure revenue caps encourage DSM. But we have discovered that revenue caps make profit very sensitive to fluctuations in the number of customers, which can cause excessive uncertainty in profit and undesirable incentives to minimize N. Section 4.5 addresses this problem of the standard revenue cap

of existing units, the system fixed cost is small. If some existing units are on the books at values well above their current market price, however, then we have "stranded assets," and a will be substantial.

[49] It is not uncommon for customer access charges, especially in the residential classes, to be priced below marginal cost.

[50] Note that all we have done is factor the N out of E after we describe E as qN, and the N out of L after we describe L as kN. This does not contradict our original formulation it only reveals more of the structure hidden inside Equation 4-1.

[51] Note that we do not hold profit equal to zero or even constant when differentiating.

and then formally analyzes the power of the various incentives. Sections 4.6 through 4.9 considers the price-setting behavior of firms under these mechanisms, a topic on which we have not yet touched.

4.5 The Revenue-per-Customer Cap

The powerful incentive to minimize N under a revenue cap has two associated problems. If the utility can influence its number of customers, perhaps by deliberately losing customers to alternative fuels, self generation, or retail wheeling, this incentive will induce perverse behavior. The second problem is more common, an excessive unpredictability in profit due to the dependence of profit on N. Fortunately, there is an easy solution to both of these problems: the revenue-per-customer cap mechanism, which is defined as $R/N < \bar{R}_N$:

$$\begin{aligned} \text{Revenue-per-Customer Cap:} \quad & R < \bar{R}_N \cdot N \\ \text{Profit:} \quad & \pi = -a + (\bar{R}_N - b - cq - dk)\,N \approx 0 \end{aligned} \tag{7}$$

We can see in the equation that there is now an incentive, of approximately a/N, to maximize N, exactly as with a price cap. (For details, see the previous calculation of $d\pi/dN$.)

At this point it is useful to summarize the similarities and differences among the three incentive schemes just described. To do this we need to make a few assumptions about the relative magnitudes of marginal costs and prices, and about the level of profit. These assumptions are made to illustrate the above theoretical points but are not intended to be accurate estimates for any particular utility. We will use the assumptions displayed in Table 4-1.

Table 4-1. Assumptions for Computing Incentive Power

Quantity		Magnitude as a % of Revenue
Access Revenue	$P_N N$	10%
Energy Charges	$P_E E$	90%
Demand Charges	$P_L L$	0%
Fixed Cost	a	10%
Customer Costs	bN	20%
Energy Costs	cE	45%
Capacity Costs	dL	24%
Profit	π	1%

Notice that costs add up to 99 percent of revenue, so that profit is one percent. This is not a low profit level both because it is expressed as a percent of revenue instead of, as is typical, a percent of assets, and because it is economic profit, which is measured after allowing for the cost of capital. As mentioned previously, a can be either nearly zero or, if the utility would end up with significant stranded assets in a competitive world, it can be quite large. For our example, we will take a to be ten percent, which we consider to be an intermediate value. This value mainly affects the incentive on N, which can easily be recalculated by the reader to suit any other value of *a*. The other values are much more difficult to estimate accurately, but their relative magnitudes appear realistic. Note that capacity costs are set at 24 percent, not because they are known more accurately but to leave room for one percent profit.

Prior to comparing the three PBR approaches, recall our discussion in Chapter 1 of the power of an incentive mechanism. Incentive power can be measured by the fraction of each dollar of cost decrease that is ultimately kept by a firm. Thus, if the utility sells another 10 kWh, thereby increasing its costs by one dollar, and if this dollar adds fifty cents to the utility's profits, then the power of the incentive to sell kWhs is said to be ½, or 50 percent. Mathematically, this is expressed as $(d\pi/dX)/(dC/dX)$, where X is the quantity affected by the incentive. It can be noted in advance that with $C = a + bN + cqN + dkN$, $dC/dN = (C-a)/N$, $dC/dq = cN$, $dC/dk = dN$. All of the numerical results in Table 4-2 can be computed from the values in Table 4-1.

Table 4-2. Comparing Price Caps with Revenue Caps

	Price Cap		Revenue Cap		Rev/Customer Cap	
X	dπ/dX	Direction & Power	dπ/dX	Direction & Power	dπ/dX	Direction & Power
N	(π+a)/N	+ 11%	(π+a−R)/N	− 90%	(π+a)/N	+ 11%
q	$(P_E-c)N$	+ 100%	−cN	− 100%	−cN	− 100%
k	$(P_L-d)N$	− 100%	−dN	− 100%	−dN	− 100%
a	−1	− 100%	−1	− 100%	−1	− 100%
b	−N	− 100%	−N	− 100%	−N	− 100%
c	−E	− 100%	−E	− 100%	−E	− 100%
d	−L	− 100%	−L	− 100%	−L	− 100%

In Table 4-2, notice that the three PBR mechanisms behave identically except in the areas noted by the shaded cells.[52] This means all three have the same cost-minimization incentives, and all three treat peak load per customer, *k*, the same. As noted, the standard revenue cap produces a strong and anomalous negative incentive on *N*, but the per-customer revenue cap exactly realigns this incentive with that of a price cap. Thus the only difference

[52] Actually, the comparison is not so simple. In order to simplify presentation, we have ignored demand elasticity. This is not a problem under price caps, where price is essentially fixed, but it is under revenue caps. For low short-run elasticities, the needed correction is not large, but when near or to the left of the peak of the revenue function shown in Figure 4-1, the effect is dramatic. An exact computation of incentives is shown in Volume II, Appendix C where we compute the energy-efficiency incentive of a hybrid cap.

between price caps and revenue-per-customer caps is in their effect on q, energy use per customer.

The two revenue caps differ dramatically from price caps in their effect on per-customer energy use, q; under the current price structure, they treat DSM far more favorably than do price caps. The particular incentive levels for q depend on the values of the marginal cost of energy, c, and the energy charge P_E. However the *difference* between the price-cap and revenue-cap incentives for DSM is exactly equal to total energy charge divided by total energy cost. In our example, $P_E E$ is 90 percent of revenue and energy cost is 45 percent of revenue, so the power of revenue caps to encourage DSM is 200 percent greater than the power of a price. In order for the two mechanisms to treat DSM the same, $P_E E$ would have to be zero, a circumstance that is neither likely nor desirable.

4.6 Crew and Kleindorfer's Critique of Revenue Caps

So far we have considered the utility's behavior with respect to costs and customers. Now we must consider pricing. In this regard, a *potentially* devastating critique of revenue caps was put forward recently by Crew and Kleindorfer (1995) and Costello (1995) has made a related criticism.[53] Crew and Kleindorfer prove that a revenue cap, if implemented without any other regulatory constraints, will induce a firm to set its price higher than if the firm were a pure monopoly. Because this would be disastrous from a public acceptance viewpoint, and highly inefficient from an economist's viewpoint, it is necessary to modify the regulatory mechanism in order to avoid this outcome. We will argue that some modifications that accomplish this goal are already in use by PUCs although they may not have been introduced with this intention.

To find a corrective mechanism we must first understand the critique. Crew and Kleindorfer's argument notes that an unconstrained monopolist will choose a profit maximizing price, P^*, which will induce a monopoly level of demand, Q^*, and a monopoly revenue, $R^* = P^* \cdot Q^*$. If the regulator sets the revenue cap, $\bar{R}$ higher than R^*, the monopolist will simply ignore it because a lower revenue maximizes profits. To have any impact at all, the regulator must set $\bar{R} < R^*$.

Assuming $\bar{R}$ is less than R^*, the firm will be forced to raise or lower P in order to reduce revenue and satisfy the regulator's constraint. Generally either strategy is possible: at an extremely high price, sales will fall to such an extent that revenues will decline[54] while as

[53] Costello argues that "if price falls and the price elasticity of demand exceeds one, total bills increase." Reversing this logic we have that the utility can reduce revenue by raising price.

[54] If this were not true, the monopolist would set an infinitely high price. In fact the monopolistic price is always in a region where revenues decline with price increases.

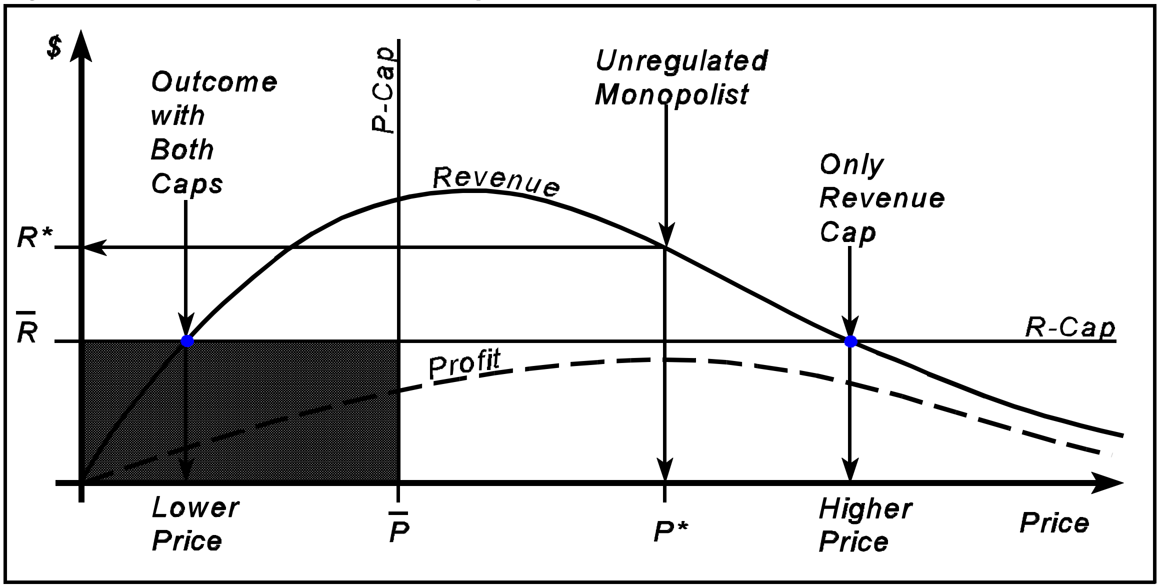
price approaches zero, revenues also decline. So let us consider a high price and a low price, both of which exactly satisfy the constraint on *R*. Because profit is simply revenue minus cost, and revenue is $\bar{R}$ in both cases, the only difference is cost. More electricity will be sold at the lower price, so the cost of generation will be higher at the lower price. Consequently the higher price will be chosen. The higher price is so high that it reduces revenues to $\bar{R}$, which is lower than R^*; therefore, the "high" price must be even higher than the monopolist's price.

The following figure illustrates this argument. It is important to note that the argument depends on essentially only three assumptions: (1) that at a sufficiently high price, revenue will decline to $\bar{R}$, (2) that the total cost of generation increases with the quantity generated, and (3) that the dynamics of reaching the equilibrium don't matter. The first of these could be false though much empirical work points toward a long-run elasticity greater than one at current price levels, and elasticity is likely to increase at higher levels.[55] It is nearly impossible to imagine that the second assumption is false. As will be demonstrated in Section 4.8, the Achilles' heel of the analysis is the third point. Short-run demand elasticity coupled with regulatory intolerance of long "temporary" violations of the cap will prevent the Crew-Kleindorfer effect if long-run demand elasticity is greater than one. But, as Section 4.8 also demonstrates, related problems remain.

Figure 4-1 depicts both the Crew-Kleindorfer dilemma and a mechanism for avoiding that dilemma. Because a firm prefers a high price to a low price at the same revenue, it is easily seen that when $\bar{R}$ is imposed as a cap, the firm will choose the high-price method of meeting that constraint.

[55] If this is false then a true electric power monopoly would raise price without limit. This would be a surprising phenomenon.

Figure 4-1. The Effect of Revenue Caps on Price



Fortunately, a simple method exists for prohibiting the economically rational response to a revenue cap, and that is a price cap. It is a bit surprising that both caps can be binding simultaneously; one would think that if the price cap were binding, the revenue cap would not be. This argument would imply that if the price cap had any effect it would simply replace the revenue cap and thus eliminate all of its incentive properties. But Figure 4-1 shows this is not true.

A price cap, placed as shown at $\bar{P}$, will be binding in a global sense while the revenue cap, $\bar{R}$, will continue to bind at the margin. We say that the price cap is binding globally but not marginally because it does not prevent a small (marginal) change in price, but it does prevent the desired large change in price from the "lower" price to the "higher" price. Thus the price cap will prevent a large discrete change in price to the high-price profit maximum while the revenue cap will prevent marginal changes in price. The result is a revenue cap that maintains the incentive properties desired by DSM advocates but without any hint of the pricing problem identified by Crew and Kleindorfer.

This technique works only if a firm's initial price level places it to the left of the revenue maximum as shown above. If the firm starts to the right, on the downward sloping part of the revenue curve, then the firm can only lower revenue by (1) gradually raising price, or (2) lowering price in a large discrete jump. (On the left side of the revenue hill, a small reduction in price leads to an increase in revenue.) A price cap that prevents a firm from satisfying the revenue cap by increasing price will necessarily force a large discrete price reduction; i.e., the firm will have to jump to the left side of the revenue "hill." Because of this, even the mildest revenue cap (measured by the size of the required revenue reduction) will have a dramatic impact on price and profits. Such a form of regulation is unpredictable in its consequences and thus quite risky.

To recapitulate, if a firm starts on the left side facing a price cap that prevents it from moving to the right of the revenue maximum, then the firm can only reduce revenue by lowering prices and moving to the left, and it can do this with a small change in price. But if a firm starts on the right, a binding price cap will prevent it from lowering revenue by moving to the right, and will force it to move all the way to the left side of the revenue hill by making a discrete and possibly large downward shift in price.

Thus, for a firm on the right, a revenue cap that forces even a small reduction in revenue, can force a large price reduction. If the firm successfully accommodates this price reduction it will be paid for either out of excess profits or by cost reductions. But the if it cannot find large enough cost reductions this small revenue reduction (and large price reduction) can put the firm out of business or force the regulator to back down.

The auxiliary price cap has unpredictable results when used on a firm to the right of the revenue maximum. Also, as will be demonstrated in Section 4.8, Crew-Kleindorfer-style difficulties persist even when short-run dynamics are accounted for. Consequently we are still in need of a safe and predictable mechanism that eliminates the problems of a revenue cap while maintaining its desired incentive properties. The hybrid price-revenue cap presented in the next section satisfies both of these objectives.

4.7 Designing a Hybrid Price-Revenue Cap

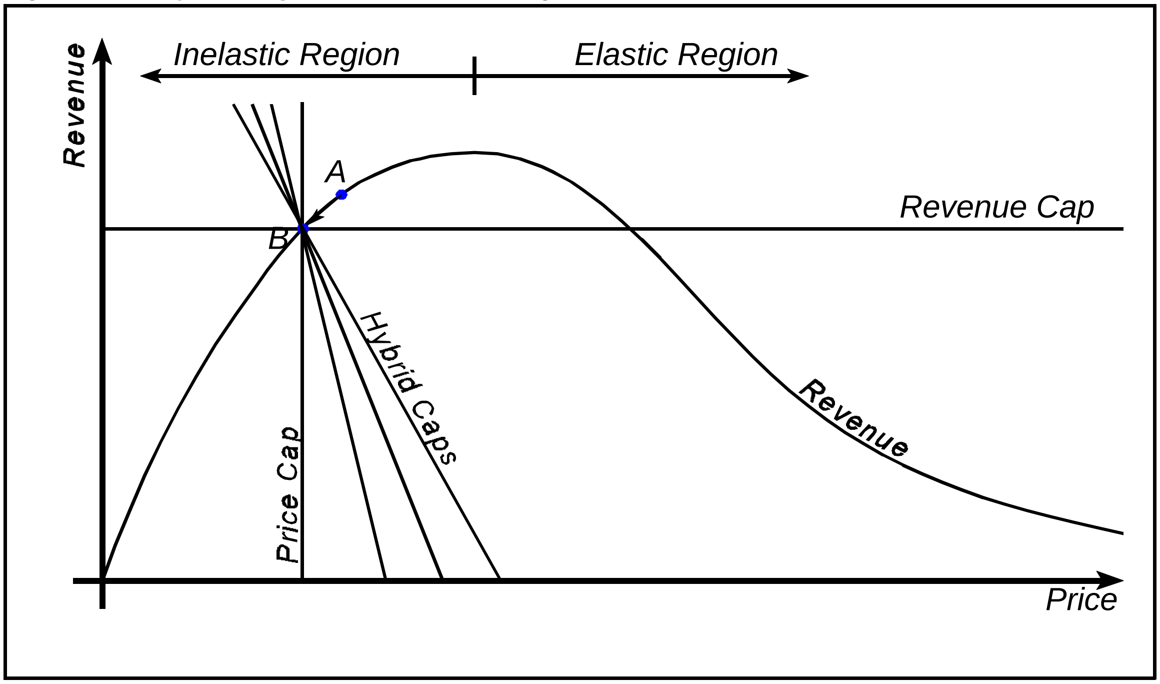
We have shown that a price cap discourages DSM while a revenue cap can induce perverse pricing behavior. Fortunately, a hybrid price-revenue cap can be designed to avoid any possibility of the Crew-Kleindorfer dilemma, and to avoid the energy efficiency disincentives of a price cap. As we will see in Section 4.9, a hybrid cap also helps curb the strong distorting effects on relative prices that revenue caps encourage.

A hybrid price-revenue cap is represented by a diagonal line in the revenue-price diagram and is represented algebraically as follows:

$$\begin{aligned} \text{In Revenue-Cap Form:} \quad & R \le \bar{R} - b \cdot P \\ \text{In Price-Cap Form:} \quad & P \le \bar{P} - c \cdot R \end{aligned} \qquad \textbf{(8)}$$

Note that the same hybrid cap can be represented in two distinct but equivalent forms: as a variable revenue cap or as a variable price cap. In the revenue-cap form, the cap decreases as the utility increases its price. In the price-cap form, the cap decreases as the utility increases its revenue. Note that in a hybrid cap, $\bar{R}$ and $\bar{P}$ are fixed, but they are no longer the limits on R and P; the limits are now lower and variable. The entire right-hand expression is the cap, and in both cases this is significantly lower than the barred variable. Also note that the utility controls both R and P, but that it does not control them independently.

Figure 4-2. Hybrid Caps in the Inelastic Region



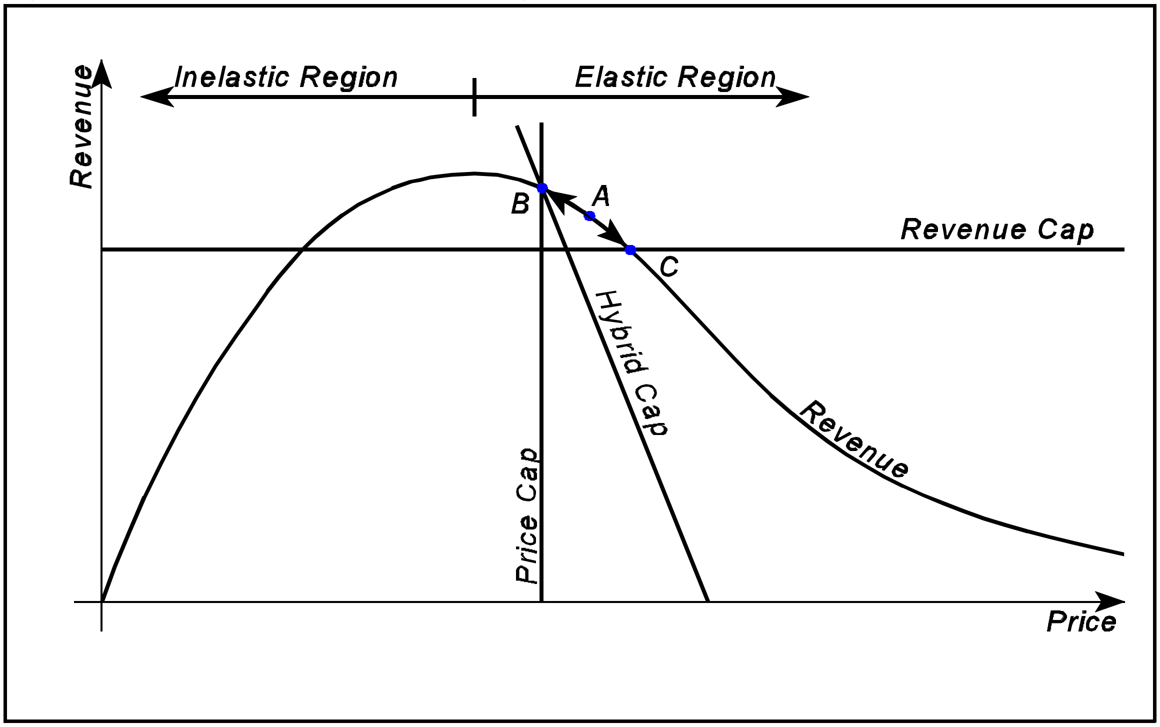
We now present a graphical representation of hybrid caps. It turns out that the behavior of these caps is quite different in the upward sloping (inelastic) region of the revenue curve than in the downward sloping (elastic) region. In the latter region it is necessary determine the slope of the hybrid cap in accordance with the maximum elasticity of electricity demand.[56]

Figure 4-2 shows three examples of hybrid caps in the inelastic region. All three are set to behave exactly like the price cap that is shown with them. That is, they are designed so that they will induce the same price behavior as induced by the price cap. A revenue cap is also

56 To review the connection between elasticities and the shape of the revenue function, consider first an elasticity of one, which by definition is the dividing line between elastic and inelastic. A demand elasticity of one means that when price increases by 1%, quantity demanded will decrease by 1%. Because revenue is the product of price and quantity, it remains unaffected by this particular change in price and quantity. This means that at the divide between elastic and inelastic, the revenue curve is perfectly flat. This indicates the top of the revenue function plotted in Figures 4-1, 2 and 3. If demand is elastic, then a 1% change in price produces a larger decrease in quantity demanded; thus the quantity effect dominates, and revenue declines when price increases. The downward-sloping region on the right-hand side of figures is the elastic part of the demand function. Similarly, the upward-sloping region is the inelastic part of the demand function.

shown, and is drawn so that it will produce the same outcome, provided the Crew-Kleindorfer effect is prevented in one of the ways discussed above.

Figure 4-3. Hybrid Caps in the Elastic Region



The elastic case, shown in Figure 4-3, presents a different story. Again, the firm begins at point A, but this time a price cap and a revenue cap will have opposite effects. A revenue cap will lower revenue and raise price (point C), while a price cap will lower price and raise revenue (point B). If we use the same revenue cap as in the inelastic example, we generate the unfortunate outcome predicted by Crew and Kleindorfer (and suggested by Costello): the firm raises prices in order to lower revenues. The hybrid cap is designed to cause the same price and revenue effects as the price cap, but without any chance of causing a price increase and with less anti-DSM bias than the price cap.

In order to guarantee that the hybrid cap behaves similarly to a price cap and prevents the Crew-Kleindorfer dilemma, it is only necessary to choose its slope to be more negative than the revenue curve. This should not be difficult; even though the empirical literature is vague, it strongly indicates that long-run elasticity is less than two.[57] From this elasticity we can compute a safe slope for the hybrid incentive as follows. We begin with a standard constant elasticity demand function in which quantity, Q, is considered a function of price, P, and in which α, and elasticity, η, are constant:

[57] For a review of the empirical literature on demand elasticities, see Volume II, Appendix C.

$$Q = \alpha \cdot P^{-\eta}$$

$$R = P \cdot Q = \alpha \cdot P^{1-\eta}$$

$$\frac{dR}{dP} = \alpha \cdot (1-\eta) \cdot P^{-\eta} \qquad \textbf{(9)}$$

$$\frac{dR}{dP} = (1-\eta) \cdot Q = -Q \qquad \text{when } \eta = 2$$

This gives us the slope of the revenue curve, and, because we want the slope of the hybrid cap to be less than this slope, the equation also determines the slope of the steepest allowed hybrid cap. From the slope of the hybrid cap, it is easy to write down particular cap formulas. For instance, to cap the utility at its initial price, revenue, and quantity (P_0, R_0 and Q_0), we would use the following hybrid formula:

$$\text{Revenue Cap Form:} \quad R \le 2R_0 - PQ_0$$

$$P \le \frac{2R_0 - R}{Q_0} \qquad \textbf{(10)}$$

$$\text{Price Cap Form:} \quad P \le 2P_0 - \frac{R}{Q_0}.$$

Comparing these to the general forms given by Equation 4-8, we find that $\overline{R} = 2R_0$, and $\overline{P} = 2P_0$. Note that in the revenue-cap form, the revenue cap decreases with a price increase, while in a price-cap form, the price cap decreases with a revenue increase. Obviously this is only one of a whole family of hybrid caps that can be used. As long as they are based on an elasticity less than two, they will be safe from the Crew-Kleindorfer dilemma. However, as the elasticity that the cap is based on decreases from two, the hybrid cap becomes more and more like a price cap and thus loses its positive DSM incentive properties.

4.7.1 The Incentives of a Hybrid Revenue-per-Customer Cap

In Section 4.5 we argued for a revenue-per-customer cap as a replacement for a pure revenue cap, but then, when we faced the complexities of the Crew-Kleindorfer dilemma, we simplified our analysis by treating only the pure revenue cap. This cost us nothing in terms of insight, but in actual applications we would want to return to a hybrid form of the revenue-per-customer cap. So far we have also avoided the question of exactly what incentives, for or against DSM, will be generated by a hybrid cap. We know only that its behavior will lie somewhere in between a pure price cap and a pure revenue cap. We now remedy both of these shortcomings, and restore some of the pricing detail that has also been left behind.

The simplest hybrid of a price and revenue-per-customer cap uses a hybrid formula only on the energy component of costs and revenues. For the other components a simple rigid price cap is used. This may leave some minor problems with the incentive for load management, but generally, as was seen in Section 4.5, the utility has an incentive towards effective load management even under a price cap. Thus the following simple form should be sufficient, though a more complex form would be needed if price flexibility were desirable.

$$P_N < \bar{P}_N, \qquad P_L < \bar{P}_L, \quad \text{and}$$

$$P_E < \bar{P}_E - \frac{R_E}{q_0 \cdot N} \tag{11}$$

Where P_N is the price of access, P_L is the demand charge, P_E is the price of energy, and q_0 is the initial energy use per customer. This hybrid cap is based is based on an elasticity of two. Note that because of the magnitude of the subtracted revenue-per-customer term it is necessary to set $\bar{P}_E$ almost twice as high as P_E.

Turning to the question of incentives for energy efficiency programs (DSM), we are particularly interested in the utility's incentive to reduce *q*, the energy use per customer. The calculation of this incentive is quite difficult, but the interested reader may find it in Volume II, Appendix C. Fortunately the calculation has a simple outcome. The utility will have an incentive to reduce *q* provided

$$P_E \cdot E < 2c \cdot E. \tag{12}$$

Returning to Table 4-1, we find that we have estimated $P_E \cdot E$ at 90 percent of revenue and $c \cdot E$ at 45 percent of revenue. Recall from Table 4-1 that $P_E \cdot E$ is energy charges and $c \cdot E$ is energy costs. This inequality holds if customers are charged for energy less than twice the cost of producing the energy, taking into account the separate charges and costs for access and power. Thus inequality 4-11 fails, but would hold as an equality. This indicates the firm will have no incentive to make any change in *q*. If the price of energy had been set at marginal cost, then the utility would have been motivated to reduce *q*. These findings indicate that a hybrid of a price cap and a revenue-per-customer cap can in fact provide protection from Crew-Kleindorfer pricing problems, and retain sufficient incentive properties from its revenue-based side to mitigate the adverse DSM effects of a pure price cap.

4.8 Dynamic Adjustments and the Need for Hybrid Incentives

As is well known, the demand for electricity is quite inelastic in the short run. As was noted at the end of Section 4.6, this implies a revenue curve that slopes only upward, which in turn negates the possibility of the Crew-Kleindorfer effect. This section shows why this short-run analysis is inadequate and how to reconcile the short- and long-run views. The results are that, while the Crew-Kleindorfer effect is generally suppressed, it can be enabled by effective

DSM, and that short-run elasticities can trigger an opposite but equally problematic effect. These possibilities justify the use of a hybrid mechanism. We make these points by focusing on three specific cases, but perhaps the most important lesson of this section may be learned simply by noting the complexities of the dynamics and gaming possibilities that are introduced by a pure revenue cap.

If the long-run demand for electricity were inelastic as is the short-run, both short- and long-run revenue curves would slope only upwards, and the Crew-Kleindorfer effect would indeed be impossible. Some may believe this to be the case, and the empirical literature, reviewed in Volume II, Appendix C, does not refute this possibility. It is interesting to note however, that because the horizontal axis measures price, a revenue curve that slopes only upwards implies that an unregulated monopolist would maximize its profits by raising price without limit. Those who find such a profit maximizing strategy implausible, must believe there is a region of elastic demand, at least for higher prices.

Another crucial observation regarding demand, is that as the industry becomes more competitive and distribution companies lose some of their monopoly power, competition will alter the demand curves they face. Since, firms in an N-firm Cournot oligopoly typically face individual demand curves that are N times more elastic than the industry demand curve, one can expect this effect to be quite dramatic, especially regarding long-run demand. These considerations lead us to examine three particular cases all of which assume that *short-run demand is inelastic*, but which vary with respect to long-run assumptions and the effectiveness of DSM.

4.8.1 Case 1: Revenue Curve as in Figure 4-1 with Utility Starting on the Left

In this case we assume that the long-run revenue curve behaves as in Figure 4-1: it is inelastic at low prices and elastic at high prices. We also assume that the utility starts in the long-run inelastic region.[58] Without the constraint of short-run inelasticity, a revenue-capped firm would simply choose the high-price point shown in Figure 4-1. But if demand is short-run inelastic choosing such a high price will send revenue through the roof in the short run. Since a complete adjustment to the long run takes forever (at least in theory), the firm would actually have to overshoot the price target. Assuming the regulators will not tolerate a “temporary” violation of the revenue cap lasting for several years, such a strategy will be disallowed.

Conclusion: The Crew-Kleindorfer dilemma does not affect a firm that faces a demand curve that is both short-run inelastic and, at current prices, long-run inelastic. This is true even if a profitable high-price long-run strategy exists.

[58] Although empirical evidence does not demand this conclusion, a well regulated industry will face inelastic long-run demand.

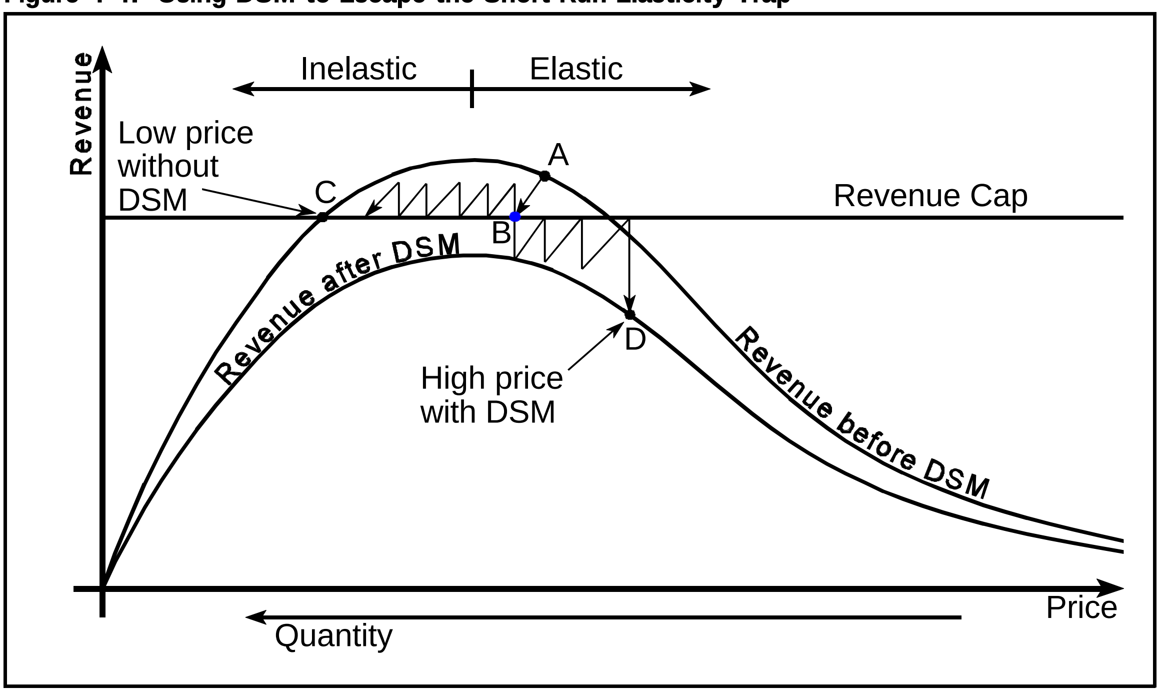
4.8.2 Case 2: Long-Run Demand is Elastic at the Initial Price

In this case we analyze point (A) on the down slope of the revenue curve shown in Figure 4-4, or perhaps a point that, due to competition, is on a curve that slopes downward at all prices. We have drawn the entire long-run revenue function, but drawn only small parts of several short-run curves: the upward sloping parts of the zigzag paths.

From point A, there is only one short-term option for the firm: to reduce price and move down its short-run revenue function to B, taking advantage of the short-run inelasticity of demand, and arriving at a lower revenue that complies with the revenue cap. (Ignore the path from B to D until case 3.) After arriving at B, the firm finds its revenue slowly rising as customers move toward their long-run demand curves. This violates the revenue cap, and at some point this violation will be noticed, and the utility will be required to comply with the cap once again. Once again it must decrease price, taking advantage of short-run demand inelasticity. This takes it on the next short diagonal path down and to the left. As this process continues, it is driven to lower and lower prices, and finally to C, even though there is a high price at which the revenue cap would eventually be satisfied.

Conclusion: A firm that is faced with a restrictive revenue cap, short-run inelastic demand and long-run elastic demand, will generally *not* be able to execute the Crew-Kleindorfer strategy. Instead they will be forced into repeated price *cuts* possibly leading to bankruptcy.

Figure 4-4. Using DSM to Escape the Short-Run Elasticity Trap



4.8.3 Case 3: Long-Run Demand is Elastic and Demand Shifts Down

This is identical to case 2, except that the firm's revenue curve unexpectedly shifts downward by enough to more than satisfy the revenue cap. This could be an autonomous shift caused by weather or a downturn in the economy, or it could be a shift caused by large-scale, utility-sponsored energy efficiency programs. Although DSM seems unlikely to produce a large short-run effect, DSM is of interest because it is the target of the revenue cap, and may for this very reason be unexpectedly successful.[59] This shift is depicted by the lower revenue curve in Figure 4-4.[60] If such a demand shift occurs, then at point B the firm will be above its new long-run revenue curve, and revenue will fall toward this lower curve. This fall in revenue takes the firm's revenue below the cap, thereby allowing the firm to raise prices even though the short-run effect is to increase revenue. This process will continue until the firm reaches the point of maximum monopoly profits, shown as point D.

Conclusion: The firm may use DSM to escape the short-run elasticity constraint, and thereby make its way to the monopolist's operating point.

Our final conclusion based on these three cases must be that although short-run inelasticity generally prevents the high price response to revenue caps described by Crew and Kleindorfer, case (2) nonetheless demonstrates a related problem, and case (3) shows that successful DSM could make the Crew-Kleindorfer strategy viable. Cases (2) and (3) make a pure revenue cap too risky in most real situations.

In the Section 4.6 we pointed out that an auxiliary price cap could restrain the simple Crew-Kleindorfer dilemma, but can such a mechanism be invoked to remedy the problems of cases (2) and (3)? Unfortunately it cannot be. In case (2) a price cap would have no effect, and in case (3) it would become locally binding if it did have any effect. In this case we end up with higher prices and price-cap regulation. Thus the only useful recourse in cases (2) and (3) is the hybrid price-revenue cap of Section 4.7.

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59 Note that if a regulator relies on a revenue cap, and no other controls, to motivate DSM, the utility will find it advantageous to run a number of programs that reduce demand, but that are not socially beneficial. This may widen the scope of "successful" DSM considerably. Also note that in the particular situation of this example, the payoff from "successful" demand reduction will be far greater than we have computed in our previous examples. These two effects could induce DSM programs quite different than anything seen in the past.

60 Recall that when DSM shifts demand; this does not mean simply moving along the demand curve, a process that involves only changing price and waiting for the response. Instead, DSM shifts the demand curve itself, so that less is demanded at any price, whatever that price may be. When the demand curve shifts down, the revenue curve obviously shifts down too.

4.9 Flexible Caps and Relative Prices

In the first part of this chapter we discussed incentives for a firm to affect costs, quantity, and number of customers. In the second part we discussed the overall price response to a revenue cap. We now turn to a third area of consideration, applicable to both price and revenue caps whenever or not they are of the rigid form described in the first section. Because price caps are generally not rigid, and because a revenue cap or a hybrid cap is by its very nature flexible, this topic is essential to a complete understanding. The topic we now turn to is a firm's strategy for setting relative prices when given price flexibility under PBR.

Both revenue caps and price caps affect relative prices, but the effects are quite different. Price caps are well known for their ability to induce prices similar to Ramsey prices.[61] As we will soon see, revenue caps move prices strongly in the opposite direction. Ramsey prices are designed to maximize consumer welfare, given that a firm must cover costs. Ideally, prices should be set equal to marginal costs, but when there are fixed costs of production, these will not be covered by this "first-best" pricing scheme; instead, it is necessary for the firm to use a markup over marginal costs. The Ramsey problem is to find the set of markups that just covers fixed costs while making the smallest possible reduction in total consumer surplus. The solution to this problem is to use the set of markups that have minimum effect on consumer demand. This is accomplished by marking up low-elasticity products the most and high-elasticity products the least.

Although price caps were not invented with the intention of inducing socially optimal relative prices (Beesley and Littlechild 1989), it was soon discovered that, in a multi-product firm, when the individual price cap is replaced with a Laspeyer's price index, this will induce markups that are exactly proportional to Ramsey markups. Consider a flexible price cap based on a Laspeyer's index, which is the typical practice. (The first term in Equation 4-13 is a Laspeyer's price index because it weights present prices (superscript 1) by last period's quantities (superscript 0). This means it is required that:

$$\sum P_i^1 \cdot Q_i^0 \;\le\; \sum P_i^0 \cdot Q_i^0 \;=\; R^0 \tag{13}$$

where the sum is over products indexed by i. Although this equation looks something like a revenue cap because the cap is revenue at time 0, *it does not cap revenue*; instead, it caps a weighted sum of prices. This makes it a flexible price cap. In response to such a cap, the utility will set new relative prices, which will in turn induce new quantities. In the next round, the new quantities, Q_i^1, can be used as the new weights on price. If we continue to repeat these steps, the quantities will eventually converge to stable values. At these values, the profit maximizing prices will satisfy the following markup equation:

[61] Vogelsang and Finsinger (1979).

$$\frac{P_i - C_i}{P_i} = \frac{1}{\epsilon_i}(1 - \lambda), \qquad \text{where } \lambda < 1 \tag{14}$$

In other words, markups are proportional to the reciprocal of the elasticities, ϵ_i. The proportionality constant is different than for true Ramsey prices because the firm is allowed to earn a profit, not just to cover costs. The proportionality constant, λ, measures the value to the firm of raising R^0, and it is known technically as the shadow price of relaxing the constraint.[62]

It is difficult to explain this behavior intuitively because the effect is not a very powerful one, but we examine a simple example in order to see the various forces at work, and to compare this effect to the more dramatic relative price effect induced by a revenue cap.

Table 4-3. Price Caps Affect Relative Prices Only Weakly

	Equal Markups		Flexible Markups	
Price Cap:	2.20		2.20	
Product Number	1	2	1	2
Elasticity	0.30	0.70	0.30	0.70
Marginal Cost	1.00	1.00	1.00	1.00
Price	1.10	1.10	1.14	1.06
Quantity	0.97	0.94	0.96	0.96
Profit	0.10	0.09	0.14	0.05
Total Profit		0.191		0.192
Change in Profit: (1)				0.0014
Change in Consumer Surplus: (2)				–0.0007
Change in Social Welfare: (1)+(2)				0.0007

We can see from the table that when the firm is allowed to price flexibly, it chooses to increase the markup on the inelastic product (number 1).[63] This reduces the sales of product 1, but not by as much as the sales of product 2 are increased when the price of product 2 is lowered.[64] Since the price cap allows the price of one product to go up as much as the other goes down, there is a net gain in sales. Sales are profitable, so there is a small net gain in profit. This gain in profit is less than one percent of the initial profit level (this is very much less than 1% of equity). Thus the effect on profit is rather small, so the firm does not have a very strong motive to make such a change.

62 The derivation of this result is given in Einhorn (1991, p. 36).

63 The products, for example, could be capacity and energy, or energy for customer class A and for customer class B.

64 Iso-elastic demand curves are used throughout these examples.

We now turn to the effect of a flexible revenue cap on relative prices. This revenue cap can be expressed algebraically as follows:

$$\sum P_i^1 \cdot Q_i^1 \leq \sum P_i^0 \cdot Q_i^0 = R^0 \qquad \textbf{(15)}$$

Although this expression looks very similar to that of the flexible price cap, notice that current prices are now weighted by current quantities instead of past quantities, so revenue is actually being capped in this case. When this formula is analyzed just as the price-cap formula was, a new markup equation is found. Both of these derivations may be found in Volume II, Appendix C.

$$\frac{P_i - C_i}{P_i} = \frac{1}{\epsilon_i}(1 - \lambda) + \lambda, \quad \text{where } \lambda > 1 \qquad \textbf{(16)}$$

Table 4-4. Revenue Caps Affect Relative Prices Strongly

	Equal Markups		Flexible Markups	
Rev-Cap	2.10		2.10	
Product Number	1	2	1	2
Elasticity	**0.30**	**0.70**	**0.30**	**0.70**
Markup	0.09	0.09	-0.72	0.68
Marginal Cost	1.00	1.00	1.00	1.00
Price	**1.10**	**1.10**	**0.58**	**3.17**
Quantity	0.97	0.94	1.18	0.45
Profit	0.10	0.09	-0.49	0.97
Total Profit		0.19		0.48
Change in Profit: (1)				0.280
Change in Consumer Surplus: (2)				-0.732
Change in Social Welfare: (1)+(2)				-0.447
λ = 1.74				

This formula differs from the price-cap markup formula in two ways. First, an extra λ is added to the inverse elasticity term. Second, λ is greater than one, which causes the inverse elasticity term to be negative. This reversal of sign means that the firm will decrease rather than increase the markup on low elasticity products, as shown in Table 4-4.

Notice that all of the effects are more dramatic for the revenue cap than for the price cap. Price increases not by four percent but by 300 percent, and decreases not by four percent, but by 42 percent. Profit increases not by less than one percent, but by nearly 150 percent, and the changes in consumer surplus and social welfare are also hundreds of times larger. As the elasticity of a product approaches 100 percent, the markup on the product tends toward infinity.

Surprisingly, the reason for these effects is also subtle. For both products, an increase in price causes a strong increase in profit. In fact, the effects are similar because they are primarily caused by the increasing gap between price and cost. The advantage of increasing the elastic product's price is that this will cause less increase in revenue than will be caused by an increase in the price of the less elastic product. For this reason, the tradeoff favors a high price on the elastic product and a low price on the inelastic product.

These effects are exacerbated when one product is elastic and the other inelastic. In this case, the elastic product will be priced as high as possible, resulting in essentially no sales, which uses up a minimum of the allowed revenue. The firm can then collect the remainder of the allowed revenues from the inelastic product, which will be very profitable. These conclusions are the result of numerical analysis, so they may not apply universally. However, they are certainly true in many cases.

The above conclusions concerning overpricing may be mitigated when short-run elasticities are small, but dynamic pricing behavior will be very complex, and may well be problematic.

Because price-caps cause the inelastic product to be marked up more, and revenue caps cause it to be marked up less, we can assume that a hybrid cap *could* have a very minor effect on relative markups. Revenue caps produce the more powerful effect on relative prices, so it will probably be necessary to use a hybrid cap that leans more heavily in the direction of a price cap, in order to achieve neutrality.

A complete analysis of the effect of hybrid caps on relative prices is quite complex and beyond the scope of this paper. However, until such analysis is done, hybrid caps that allow price flexibility should be located near the price-cap end of the spectrum.

A simpler way to manage the strong relative-price incentives of revenue caps is to fix relative prices. This must be done as a separate regulatory measure, rather than being built into the revenue cap. But it is a simple matter to require a firm to keep relative prices fixed or to change them by less than a certain percent per year. A defacto constraint on relative prices is probably in effect wherever revenue caps are in use. Relative prices could be fixed using the normal rate review procedure, which is still in place. In such a setting, regulators can simply refuse to allow relative price shifts they are uncomfortable with, even those that do not violate the revenue cap. This process may result in less efficient pricing than would be achieved under a price cap with pricing flexibility, but it does effectively prevent pricing anomalies that would otherwise be caused by a revenue cap.

4.10 Summary and Conclusions

Revenue caps were proposed as substitutes for price caps in order to eliminate the anti-DSM bias of price caps while maintaining the incentives to minimize costs. We have shown that this idea is basically sound, although the use of revenue caps presents a new set of problems. Hybrid caps simply allow a utility to compromise between a price cap and a revenue cap. Fortunately it is possible (under some price/cost conditions) for such a compromise to mitigate all of the revenue cap's problems without restoring any of the anti-DSM bias found in a price cap.

The use of revenue caps poses three potential problems:
(1) The utility may dramatically alter relative prices.
(2A) The utility may respond by setting price at or above the monopoly level.
(2B) The possibility that a small reduction in the revenue cap will produce a large and unpredictable reduction in price (an effect related to the Crew-Kleindorfer effect).
(3) An incentive to reduce sales regardless of the social benefit.

The first problem can be solved by regulating relative prices, a process that is going on defacto at all utilities that are currently using revenue caps. However, the use of a hybrid price-revenue cap would significantly mitigate this problem, and a correctly designed hybrid may eliminate it completely, which would allow the utility price flexibility; a desirable step in the direction of competition.

The second two problems are both related to the shape of the revenue function. Typically revenue increases with price for low prices and decreases with price for high prices. If a firm is in the low-price region, a revenue cap with no other constraints, will allow the firm to meet the revenue cap by setting price in the high price region. This is the problem pointed out by Crew and Kleindorfer, and it is easily solved by three different techniques: (1) short-run price inelasticity coupled with restrictions on temporary violations of the revenue cap, (2) a non-binding price cap, or (3) a hybrid price-revenue cap. Currently it is probably being solved in practice by the first technique, which occurs through standard implementation procedures. The only real possibility of the Crew-Kleindorfer effect to take effect is in a market with long-run elastic demand, and the possibility of an autonomous (or DSM-caused) drop in demand that happens after the mechanism is set in motion. This seems unlikely but our recommended hybrid cap would prevent it.

Problem (2B) is much more likely to occur. It requires only that long-run demand have an elasticity near one or greater. In this case, since the Crew-Kleindorfer effect will be prevented by short-run demand elasticity, the firm will be forced to meet its revenue cap by a price reduction. But since reducing price by a modest amount does little or no good in reducing long-run revenue, the firm will eventually be forced into a drastic price cut. This would probably force the abandonment of the revenue cap in order to avoid putting the firm out of business. Again, problem 2B would be prevented by the use of a hybrid cap.

The third problem is that a revenue cap, while producing an incentive to reduce sales, does not target that incentive towards economically justified energy efficiency improvements. The incentive is too encompassing, and so encourages non-socially beneficial as well as beneficial reductions in sales. Again, a hybrid cap would greatly reduce or even eliminate this problem.

This leads us to recommend the hybrid price-revenue cap as a replacement for a pure revenue cap if one is concerned with the incentives for the utility to manipulate demand. More specifically the cap should take a revenue-per-customer approach and should be based on an elasticity of two or less. A correctly designed hybrid cap will not allow a price increase (except due to DSM) and will eliminate most if not all of the anti-DSM bias associated with a price cap. Such a cap would only need to replace the energy part of a price cap, and could take a form as simple as the following.

$$P_E < \bar{P}_E - \frac{R_E}{q_0 \cdot N} \tag{17}$$

P_E is the price of energy, $\bar{P}_E$ is like a price cap only high to compensate for the following revenue term. The subtracted term measures revenue from energy charges divided by initial energy per customer times the number of customers. Probably the most important remaining question is what changes in relative prices will be induced by a hybrid cap. Until this is answered, utilities using the hybrid cap may have to maintain the tradition of implicitly regulating relative prices.

In spite of its limitations, the subject matter of this chapter covers much new ground that should be of interest to those considering or already using revenue caps. Also in spite of the simplifications that are necessary in this chapter, it should be presumed that the basic results are true of the more complex revenue caps found in practice. Some have already made claims to the contrary, asserting for example that particular revenue caps are not subject to Crew-Kleindorfer type effects. On the face of it, such claims seem quite unlikely unless the particular caps have additional mechanisms designed to reverse the effects described in this chapter. Thus any claims for exemption from these conclusions should be documented by careful calculation before they are accepted. In particular these calculations must account for the price elasticity of demand. Although revenue-cap incentives have not been directly covered in this depth by either the academic or the policy literature, this chapter is intended only as an introductory intuitive treatment of the subject and not as a final and definitive treatment; many questions remain unanswered.

PBR and Electric Industry Restructuring: Implications for Generation Resource Planning

5.1 Overview

In this chapter, we discuss the relationship between PBR and electric industry restructuring and discuss the implications that both have on resource planning. Whether and how to plan for electric generation resources (traditional supply and renewables) and its substitutes (e.g., DSM) is an important issue of public policy because electric generation resources are long lived, require considerable amounts of capital, and can impact the environment. Planning in regulatory proceedings has historically played an important role in the selection of new resources. Industry restructuring and PBR will impact planning but competing models of industry restructuring exist and thus the future role of PBR and planning in the generation segment of the industry are unclear. We evaluate the efficacy of alternative forms of regulation, including PBR, in the context of current models of industry restructuring and the ultimate degree of competition. We focus exclusively on the generation segment as that is where much of the attention of resource planning has been paid in the past, primarily due to the high and lumpy costs and environmental impacts of new resources. Finally, we continue the discussion begun in Chapter 4 on price, revenue, and hybrid caps by considering the appropriateness of each of the mechanisms under different assumptions regarding the ultimate structure of the electric industry's generation segment.

5.2 Models of Electric Industry Restructuring

There has been much written on the topic of alternative industry structures in the electric industry (CPUC 1993b and 1994b; Cullen et al. 1994; National Council 1995; FERC 1995). We do not attempt to repeat the important debate on industry structures in this report. Yet, the type of regulation and the type of PBR that is appropriate is affected by the outcome of this debate. To facilitate an understanding of the range of possibilities, we define and use as a reference point three major models for the restructuring of the utility generation business: (1) functional separation of utility generation assets, (2) functional separation of utility generation assets with the creation of an independent transmission (pool) operator, and (3) structural separation (Table 5-1).

Before further discussion on alternative structures, it is important to remember that the traditional status quo for utilities in the U.S. is the vertically integrated utility. Under that structure, the utility owns and generates the majority of capacity and energy sold on its system. This model is rapidly devolving in the U.S. Approximately half of all new generation capacity comes from nonutility sources today and, as is clear from Table 5-1, the major policy alternatives indicated in Table 5-1 call for at least a *functional separation* of generation assets.

Table 5-1. Major Models of Electricity Industry Restructuring

Important Criteria	Generation Industry Structure: Functional Separation — Generation Only	Functional Separation — Gen. + Independent Transmission Operator	Structural Separation (Divestiture)
Generation assets are placed in:	separate division of utility co.		separate company
Transmission system run by:	utility	independent operator	not specified
Compatibility with direct access:	LOW conflict created by utility owning and operating both transmission and distribution	MEDIUM➜HIGH independent pool operator mitigates conflict	HIGH utility no longer has direct interest in generation
Example:	FERC (1995)	CPUC (1995) majority opinion	CPUC (1995) minority opinion

Under functional separation, the generation function is placed in a separate division and any transactions between the division and the rest of the utility are subject to rules regarding the transfer of products, services, information, and employees.[65] In the electricity industry, functional separation would allow existing or new generation assets to remain a part of the utility company but be subject to specific accounting and conduct rules. There are two major restructuring models that advocate functional separation. FERC's "Mega-NOPR" (1995) calls for functional separation of generation from the transmission and distribution functions and proposes rules that would provide transmission services on an unbundled, comparable basis. The CPUC's majority policy position (1995) also calls for functional separation of generation and transmission but also requires that the transmission grid be run by an independent operator. This operator would run a power pool and, it is hoped, mitigate the market power of the utility in the generation market.

65 Functional separation is required by the Federal Communications Commission for certain competitive services offered by local phone companies and by the FERC for the gas supply marketing activities of interstate pipeline companies.

Under *structural separation* or *divestiture*, the utility divests some or all of its generation assets. An open question whether the new owner of the assets can be affiliated with the utility but, at a minimum, the new owner is a separate nonsubsidiary corporation and the utility is required to interact with the generation asset's new owner no differently than it would with any other corporation. Partial structural separation was performed in the UK when the Thatcher government divested non-nuclear generating assets into two, privately held generation companies. Structural separation is also advocated in a minority opinion issued by the CPUC (1995).

5.3 Generation PBRs under Alternative Competitive Models

The three major restructuring models are not ends in themselves. Instead they are used as means to achieving a certain level (degree) of competition and customer choice. Most agree that the industry is facing a choice between *wholesale competition* and wholesale and retail competition (for simplicity, called *retail competition* or *direct access*). Under wholesale competition, utilities are no longer monopolies in the generation market. Wholesale transmission policies promote the maximum number of sellers to each franchise distribution company. Distribution companies still retain their monopoly over their "wires" business and are monopolists in the procurement function; i.e., they buy and resell generation capacity and energy to their customers. Under retail competition a competitive market is pursued in both the wholesale and retail markets. Retail competition requires that the utility provide their customers direct access to alternative supplies. As a result, the utility looses its monopoly on its procurement business.

A goal of industry restructuring is to increase the degree of generation competition, either immediately or in the future. In addition to defining the industry structures, Table 5-1 indicates the compatibility of each structure with direct access. All of the industry structures can support direct access, although achieving it with functional separation is more of a challenge than under structural separation. Structural separation is the most compatible with direct access because generation assets are no longer owned by the utility and the incentive for the utility to impede retail customer access and choice is lower. Direct access in a functionally separated industry will require that utility market power be mitigated. Having an independent grid operator for the transmission system is one such measure and, thus, that restructuring model is given a "medium-high" compatibility rating.

We have introduced models of industry structure and degrees of competition because they fundamentally affect the appropriateness of PBR. In Table 5-2 we consider the appropriateness of three regulatory regimes (COS/ROR, PBR, and price deregulation) under the two degrees of competition (wholesale and retail). We rate the appropriateness of each regulatory regime under each competitive model. Also, for each generation industry structure we indicate the type of information that would be used in a generation PBR benchmark and the role of integrated resource planning (IRP) under the framework.

Table 5-2. Appropriate Methods of Regulation Under Two Degrees of Competition

Regulatory Options or Method	Degree of Competition	
	Wholesale-only	Wholesale and Retail
I. Appropriateness of Regulatory Methods		
A. COS/ROR regulation combined with tradition IRP	LOW fuel and purchased power MEDIUM new resources	LOW information costs are high and ability to second-guess the market is low
B. PBR	MEDIUM➜HIGH depends on term of resource commitments & availability of appropriate benchmarks	HIGH during transition to competition LOW after generation market is competitive
C. Price Deregulation		LOW during transition to competition HIGH once utility market power is mitigated
II. Regulatory Process		
UNDER PBR, what information would be used for the generation benchmark?	• costs of wholesale power trades in utility's region • indexed fuel prices and preset heat rates	• costs of regional wholesale power trades • prices charged local direct access customers
Use of IRP	• assists setting of market share between, utility, NUGs, and renewables	• inappropriate for setting generation price but an important informational tool for market participants and for assessing environmental impacts

COS/ROR has had a rocky history with respect to the regulation of generation. Looking over its entire life in the U.S., one can say it has worked adequately because it has provided reliable service and has provided utilities with the necessary incentives to accumulate the tremendous amount of capital that was required to build the U.S. electric generation system. Due to the A-J effect, however, COS/ROR provides an incentive to overbuild and this incentive may have helped create the overruns in the number and cost of generating facilities, especially nuclear generating facilities, beginning in the late 1970s. Many PUCs reversed the A-J incentive beginning in the early 1980s when they refused to put all new generation costs in rate base, which led to effective authorized returns *below* the utilities' cost of capital In the wake of the disallowance debates of the early to mid-1980s came integrated resource planning (IRP), which can be viewed as a process that helps to rectify the information asymmetry between the utility and the regulator. Under COS/ROR with IRP, the regulator has more knowledge to allow for better reviews of utility decisions. Also, IRP allows for the consideration of resources that have long-term or diffuse benefits, such as utility-sponsored DSM and renewables.

The appropriateness of COS/ROR in the future depends in large part on the chosen degree of competition. If retail competition is chosen, the rationale for COS/ROR and traditional IRP diminish. This is because a utility is no longer the sole procurer of generation resources; instead it relinquishes or, at best, shares that job with its customers. Further, retail competition, by definition, requires that a utility provide equal access to its transmission and distribution grid. Thus, the PUC and the utility have limited ability to build resource portfolios using any other objective than to minimize short-run costs.

If wholesale competition is the chosen model, then the appropriateness of COS/ROR depends on the term of the commitments to new resources. Despite its drawbacks, COS/ROR, when combined with IRP, has some advantages when the utility is still in the business of making long-term resource commitments. Generation resources are lumpy investments with significant lead times and long lives. Few generation PBR plans can internalize the full cost of any decisions made when a utility commits to new generation capacity. It is probably better to conduct IRP-type processes or life-cycle cost analysis than to subject the utility to an imperfect external benchmark. We recognize that there is the potential for distortions, such as the A-J effect and X-inefficiency. However, IRP is a process that is designed to overcome much of the informational asymmetry that exists between the regulator and the regulated firm. Further, under a generation PBR for a vertically integrated utility, there is the potential for intertemporal distortions. The utility will have an incentive to underspend on capital budgets during the current PBR period and then force in potentially high cost resources at each review period of the PBR. Also, PBR is not particularly well-suited for resources that have diffuse benefits or benefits that accrue over long periods of time, as is the case for some DSM and renewables resources. On balance, it is currently an open question whether generation PBR can fully replace COS/ROR for the acquisition of new utility resources under the wholesale competition model.

Although currently problematic, it is likely that PBR will become more attractive as a mode of regulation of resource acquisition as wholesale generation markets become more and more competitive. Over time, the term required for new resource commitments by utilities will likely fall. Although current contractual commitments between utilities and nonutility generators are still quite long—20-40 years is typical (Comnes, Kahn, and Belden 1995)—the emergence of electric power marketers and standardized exchange markets (like futures markets) should decrease terms.

Although we believe that COS/ROR with IRP may still be appropriate for the regulation of resource acquisition, PBR clearly has strengths over COS/ROR for the regulation of fuel and short-term purchased power. Vigorous competition exists in fuel markets and is growing in economy energy markets. PBR benchmarks are relatively easy to develop and would improve incentives for resource efficiency compared to the current mode of regulation which relies on FACs and reasonableness reviews.

Deregulation of utility generation prices is another regulatory option and should be considered the ultimate method of regulation under retail competition. As a practical matter, however, it is unlikely that any state adopting direct access will realize a competitive market overnight. A level of competition that requires no regulation will only exist when all customers are offered comparable access to a utility's transmission and distribution grid and can choose among competing suppliers of generation resources at a relatively low transaction cost. Thus some sort of regulation of a utility's generation portfolio is appropriate during the transition. Of the alternatives, some form of a PBR price cap appears most appropriate. (See Section 5.3.3. for further discussion.)

5.3.1 Comparison with Marcus and Gruenich

Marcus and Gruenich (1994) provide one of the few analyses in the literature on the topic of generation PBR and they offer a somewhat different view than the one we present. Marcus and Gruenich distinguish between "cost PBR" and "resource PBR." Cost PBR focuses on the setting of incentives for ongoing operation and maintenance expenses, including generation fuel expenses. Resource PBR focuses on the acquisition of new generation and energy efficiency resources and the long-term environmental impacts of existing and new generation facilities. Marcus and Gruenich state:

> A separate resource PBR approach is needed which assures that life cycle and environmental effects are appropriately considered and valued in the management of utility resource portfolios. Resource PBR also would give incentives to assure that programs to acquire resources are well designed to acquire the best resources from a long-term least-cost perspective using competitive processes in many cases. (Marcus and Gruenich 1994, pp. 17)

Although Marcus and Gruenich claim to support comprehensive PBR mechanisms, they specifically recommend exclusion of the following from any comprehensive PBR: DSM; research, development, and demonstration expenditures; and, possibly, nuclear power costs. For all these categories, they are pessimistic that any workable PBR may be crafted given the inability to commit for appropriately long periods of time and the difficulty of finding appropriate benchmarks. All of these resource exhibit significant timing and equity mismatches between their costs and benefits. On balance, they appear to recommend COS/ROR with continued IRP processes and some targeted PBRs in the area of O&M. This recommendation is not inconsistent with our recommendations under wholesale competition (Table 5-2) where we show COS/ROR with IRP and fuel procurement incentives as still being appropriate under wholesale competition, at least until wholesale competition allows for the construction of an adequate generation index.

5.3.2 Regulatory Treatment of Stranded Assets

Stranded assets represents the present value of assets and contractual obligations in excess of market value. Stranded assets have been created in the electric utility industry due to changes in generation technologies and fuel prices. Resources Data International (1995) estimates generation-related stranded assets to be $142 billion[66] and Baxter and Hirst (1995) estimate that stranded costs could range between $15 to $256 billion, depending on the assumptions made. The allocation of these costs has become an important issue in the electricity industry.

If an asset is known with certainty to be stranded, it is a sunk cost. If sunk, it does not represent an ongoing cost of business and there is little that can be said about the proper allocation of such costs on economic efficiency grounds.[67] Any allocation of a truly stranded asset is likely to be made based on equity and political impacts.

In reality, however, stranded assets are very difficult to quantify with certainty and utilities have some control over the ultimate size of many potentially stranded assets. For example, a utility faced with a potentially stranded long-term contract can attempt to renegotiate it and, similarly, the portion of a generating plant ultimately stranded is a function of its availability, its efficiency, and the price of competitive alternatives. Given the uncertainty surrounding stranded assets and the ability of utilities to have at least some influence the magnitude of assets stranded, it is appropriate to consider PBR for stranded asset cost recovery.

Because stranded assets, by definition, represent nonmarketable assets, it is difficult to create PBR benchmarks for them. The stranded asset benchmark should be tied to any index of ongoing operating costs. Instead, a practical approach to PBR for stranded assets is to adopt a cost-sharing rule that puts the utility at risk for some portion of a stranded asset benchmark estimated by some other means. Although the potential for initial gaming on the part of the utility is high, the quantity (benchmark) of stranded assets, or a method for calculating it, may be set by regulators. With the stranded asset benchmark or benchmark formula set, the utility may go forward in time while at risk for some percentage of the total stranded costs.

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[66] Resources Data International study as quoted in March 95 *Electricity Journal* Vol. 8, No. 2, pp. 5. It consists of the following components: generation capacity, $73 billion; purchased power, $54 billion; and coal supply, $15.

[67] The best allocation on strict economic efficiency grounds would be to allocate the cost to a portion of the economy where it will minimizes the distorting effect on allocative efficiency. This typically means allocating it to customers, debt holders, or shareholders that have fewest alternatives.

This will give the utility an incentive to actively minimize costs. This approach was taken by the FERC in the natural gas industry when it resolved the issue of recovery of gas supply take-or-pay liabilities incurred by pipelines in the 1980s. FERC adopted a relatively simple rule: recovery of 50% of any stranded asset was virtually guaranteed via recovery through demand charges to pipeline customers. Another 25% could be recovered in variable rates.[68] Because the application of stranded assets to variable rates made pipelines less competitive, they had a strong incentive to minimize stranded assets or ongoing operating costs as a way to remain competitive. In electricity, there appears to be a presumption that electric utilities may fully recover their stranded assets,[69] but like the gas industry, there is an emphasis on trying to minimize the size of the stranded asset to the greatest extent possible. A PBR that puts a utility at least partial risk for incremental recovery of stranded assets is most consistent with the overall goals of PBR.

5.3.3 Generation PBR: Price versus Revenue Caps

A conclusion of our analysis of regulatory options was that a generation PBR can potentially play an important role under wholesale competition and, during the transition to full competition, under retail competition. An important issue is what type of PBR should be chosen; the two main competing models are revenue and price caps.

In Chapter 4 we showed that both revenue and price caps are equally well-suited for controlling costs (resource efficiency) Further, we found that revenue caps are more compatible with utility-sponsored energy-efficiency programs because they, to large degree, remove the incentive to promote sales. Removing this incentive makes the utility more accepting of both the DSM programs it sponsors and other efficiency initiatives such as government appliance standards or energy conservation R&D. A drawback of revenue caps is that they must be carefully implemented to avoid allocative efficiency (pricing) distortions. The potential for abuse is especially high if elasticities of demand are high or if there is a downward shift in the demand curve. One way to mitigate the possible distortions of a revenue cap is to use a hybrid cap, which is, in essence, a linear combination of the price and revenue cap. A hybrid cap removes some of the incentive to sell more electricity without creating the incentive to raise price as a way to maximize profits.

Chapter 4 did not examine the specific situation where the utility operates in a competitive environment, which is a more realistic assumption of the generation market under retail competition. In such situations the utility is no longer a pure monopolist, its ability to set price is limited, and the utility's demand elasticities are higher because competitors can steal

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[68] See FERC (1990) where it estimated the total U.S. take-or-pay liability to be approximately $8 billion.

[69] At least this seems to be the approach being taken in California and Massachusetts (CPUC 1994b, MDPU 1995).

market share. Chapter 4 shows that the problems of revenue caps are exacerbated when demand elasticities are high. We infer that this finding applies to a utility operating in a competitive or emerging competitive market.

On the basis of this analysis, it appears that either a revenue, hybrid, or price caps could be appropriate in an industry where wholesale competition exists. Revenue or hybrid caps should be seriously considered if the utility keeps energy efficiency in its resource portfolio. With a resource portfolio that considers both generation and efficiency resources, revenue or hybrid caps can reduce the disincentives to pursue efficiency.

If, however, wholesale competition is just transitory or if the retail competition is pursued immediately, it appears that price caps make best sense during the transition to generation price deregulation. Markets that are moving to competition do not tolerate prices above market levels and revenue caps intentionally immunize the utility from the loss of market share that results from higher prices. It would be dangerous to have a utility *not* be sensitive to sales in a competitive or emerging competitive environment.

5.4 Incorporating Environmental and Energy Efficiency Goals into PBR

Until now, we have not directly addressed the incorporation of energy efficiency and environmental goals in the resource planning process and how those goals affect PBR. When resource planning takes on the consideration of these resources, it is known as *integrated* resource planning (IRP). Utility sponsorship of energy efficiency has long been considered desirable because of its environmental benefits and because of the evidence of the large gap between estimated cost-effective and actual installed efficiency. Many electric utilities have pursued large DSM programs in recent years, although the perception that retail competition is coming has caused recent declines in spending (Hirst and Eto 1995). Environmental externalities are also considered by many states in their resource planning. Although some environmental impacts have been partially internalized in the U.S., some, such as greenhouse gases, have not and state legislatures and PUCs have considered it in the public interest to add explicit environmental considerations as part of the resource planning process.

Whether or not DSM and environmental goals may be added to the utility generation resource portfolio depends largely on whether retail competition is adopted or is expected to be adopted. If the answer is “no,” there is no reason why the PBR index can not be crafted to include environmental or energy efficiency attributes. The utility, through its role as resource portfolio provider, retains considerable control of the mix of resources delivered to its customers and it is possible to regulate the portfolio using PBR. For example, the PBR index could be based on the utility’s overall total resource cost (TRC) or societal cost test (Krause and Eto 1988). Not only would the utility be incentivized to minimize its private costs, but it would be given incentives to maximize the net resource benefits of DSM programs (i.e., pursue DSM that passes the TRC test) or minimize quantified environmental impacts (i.e., pursue DSM that passes the societal cost test). In fact, a TRC-like index has been in place for NMPC (Christensen and Lowry 1992) although it is scheduled to end in 1996.[70] Similar to a PBR benchmark that takes a TRC perspective on DSM, it is possible to construct a benchmark that requires that certain resource portfolio standards be met. The portfolio standard could include minimum market shares for renewables or other "clean" generation technologies (AWEA et al. 1995) or could set adders for pollution externalities. As long as the initial generation benchmark was set high enough to incorporate the added costs of the performance standards, a utility generation PBR could represent an improvement over COS/ROR while acheiving stated environmental goals.

If, however, the answer is "yes"—that one does expect an immediate or eventual transition to retail competition—then including DSM and environmental goals in the generation resource planning process will be difficult using traditional methods, which focus on a *utility's* generation mix. With regard to environmental goals, two feasible alternatives are to impose (1) a regional taxes, fee-rebates[71], or tradeable credits on as-yet uninternalized externalities (Hamrin et al. 1994; AWEA et al. 1995) or (2) a nonbypassable "wires" charge on customers of the T&D system to fund clean supply projects. It is important note that neither type of mechanism focuses directly on a utility's generation portfolio. The tax mechanism would be a regional or national solution, affecting all generators, utility or nonutility. The wires charge would collect revenues in the nongeneration portion of the utility's business. With regard to PBR, a properly constructed tax, feebate, or credit mechanism is a natural incentive mechanism; all market participants would have an incentive to minimize costs subject to its performance standard. A wires charge is simply a revenue collection mechanism. PBR in the form of performance standards or TRC or societal cost benchmarks could, however, be used applied to the entity that *spends* the collected revenues.

5.5 Conclusion

Restructuring of the electric industry adds complexity and uncertainty to the process of implementing and designing a PBR plan. Recall, however, that one of the potential benefits of PBR is its ability to provide appropriate incentives in the transition to a competitive environment. Because of this, we suggest that regulators and utility managers not shy away from PBR because restructuring is pending. Instead, one should carefully consider the likely future generation industry structure (structural or nonstructural separation) and the eventual degree of competition (wholesale or retail competition). With a vision of the future in mind, one can then determine what kind of regulation is appropriate (COS/ROR, PBR, or price deregulation) based largely on the length of utility resource commitments and the degree of

[70] NMPC's rate cap proposal analyzed in this report no longer contains a TRC benchmark.

[71] A *fee-rebate* or *feebate* is a tax and subsidy scheme that is on balance, revenue neutral.

competition. If PBR is considered appropriate, the appropriate PBR (e.g., price, revenue, or hybrid caps) is also based on one's vision of the degree of future competition. For example, if the promotion of DSM by utilities is a desirable policy objective and if retail competition is not the preferred or considered inevitable, serious consideration should be given to revenue or hybrid caps. If retail competition is preferred or inevitable, price cap regulation on generation should be the mode of regulation until competition is adequate and can take over the price setting function. DSM or environmental goals in a world of retail competition can be achieved through tax schemes or wires charges. Finally, stranded assets play an important role in restructuring and, although there is no easily constructed stranded assets benchmark available, the likelihood that utilities can affect the amount of stranded assets makes some sort of stranded asset PBR worthy of serious consideration.

Summary of Findings and Conclusions

Economic regulation[72] of electric utilities is intended to provide a number of benefits. For customers, regulation provides access to an essential, high-quality service at prices that are reasonable with respect to cost and not unduly discriminatory. For utilities, regulation provides an opportunity to earn a fair rate of return, which has provided adequate incentive for capital formation in a capital-intensive industry. COS/ROR regulation has worked with mixed success in a vertically integrated industry. In the future, the electricity industry will be more competitive and its generation segment will be functionally or structurally unbundled. The underlying forces of restructuring are changes in technology and changes in fuel and capital markets. The electric utility is no longer a monopoly in its generation segment but it appears to retain strong monopoly powers in its transmission and distribution segments. These changes will put further stress on COS/ROR because they will put pressure on a utility to be more efficient, something that COS/ROR is not especially good at unless regulatory lag is long. Operating in a competitive environment requires quick changes in product offerings and prices to adapt to technological progress and to satisfy increasingly differentiated customer requirements. Again, these are things that COS/ROR, with its protections on earnings and its standard of nondiscriminatory pricing, is not particularly well-suited for.

PBR has been proposed as an alternative to COS/ROR for aspects of the utility still requiring economic regulation. With PBR, the standards of regulation are moved away from utility costs and returns and towards measures of performance important to customers, such as prices, revenues, or service quality. Whether the refocusing that is a part of PBR results in an improvement over COS/ROR is an open question, however. PBR is hampered by the time commitment that can be made between the utility and the regulator. Further, the incentive power of many PBR mechanisms are often diluted to levels substantially below those that exist under COS/ROR. Although PBR should increase the incentive for a utility to be efficient and make it better prepared for competition, we cannot say as of yet that utilities with PBR mechanisms are likely to be any more competitive than non-PBR utilities. Indeed, there are many utilities in the U.S. that appear to have remained very competitive under COS/ROR.

Although no definitive conclusion may be made regarding the efficacy of PBR in the electric industry, the most important findings of our study are summarized in the remainder of this chapter.

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[72] We use the term *economic regulation* to mean the regulation of revenues, prices, and service quality. We distinguish it from other types of regulation such as safety and environmental regulation.

PBR for the U.S. Electric Industry Is Still in Its Infancy

We believe that the 11 plans we collected represent a majority of the comprehensive U.S. PBR plans in existence. Of those 11, only seven plans had been adopted as of September 1995. In contrast, price cap regulation has been widely adopted for electric distribution companies in England and Wales. In the U.S., states regulate electric utility retail prices and no enabling public utility legislation *requires* PBR. Thus, PBR is necessarily more voluntary in the U.S. relative to the United Kingdom, where electricity regulation is set uniformly for all of England and Wales. Although the UK demonstrates that broad adoption of PBR in the electric industry is feasible, only time will tell how many U.S. utilities will come forward and propose plans that are acceptable to regulators.

Sliding scale regulation as practiced by Mississippi and Alabama has been in place for the longest time. Although sliding scale is clearly out of its infancy, it is inherently low powered. Assuming the mechanism assures financial viability, the utility can always survive without expending extra managerial effort. Averich Johnson and X-inefficiency problems are not necessarily mitigated any better under sliding scale than under COS/ROR.

Because of the infancy of rate and revenue cap PBR in the U.S., it is not yet possible to systematically examine utility performance under PBR. Only the results of SDG&E have been reviewed in any detail. Because PBR is a regulatory policy that is being adopted in a time of restructuring, it will be difficult to interpret results even once they are available. The question of what would have been prices, profits, or productivity under the assumption of COS/ROR will always be unknown, especially given growing competitive pressures.

PBR Requires Careful Design as Several Parameters Are Interrelated

Much of the power of PBR comes from long terms and high marginal incentive powers. To achieve long terms, PBR designers need to find accurate indices. Indices must be external to the utility's own cost or performance, or the incentive power will be lost. We identify three general types of indices (telecommunications style, railroad style, and yardstick) and the utilities in our sample demonstrate that all three are in use. Yardstick indices, which rely on peer group performance or prices, are in theory best because they use similarly-situated utilities as their information source. However, we cannot say that yardstick indices are better in practice or how well any type of index method has performed over time.

In addition to accurate indices, ways of mitigating "unacceptable" outcomes are needed for times when even the best index become inaccurate or when profits, high or low, become politically unacceptable. Unfortunately, such mitigations, which take the form of earnings sharing mechanisms, off-ramps, review triggers, and Z factors, all lead to a reduction of marginal incentive powers, at least outside of a no-sharing deadband.

When marginal incentive powers are high and terms are long, a PBR plan will possess high overall power. In this environment, it is crucial that customers receive their share of benefits in an aggressive productivity offset. However, there is disagreement over whether the "standard" model of (1) aggressive productivity factors combined with (2) high marginal incentive powers is truly desirable. A "customer-sharing" model states that customer surplus is too important to risk with a static productivity offset. Rather, the customer-sharing model includes an ongoing sharing of profits, even though doing so necessarily reduces the incentive power of the PBR mechanism. We do not recommend one model over another, but note that all implemented plans and all but one utility proposal follow the standard model.

PBR Plans Should Clearly State the Relationship of Multiple Incentive Mechanisms

Ideally, a PBR should have just one mechanism. Although it may have different components, one mechanism would clearly show the relationships of all the factors that drive measured performance and profits. We suggest that, at a minimum, PBR mechanisms combine all incentives based on dollar-denominated targets into one incentive mechanism. For example, rate incentives should be built into revenue caps and not be treated separately. PBR designers should also strive to combine supplemental incentives even if the incentives are based on nondollar targets. Such nondollar incentives are popular and include service quality, DSM performance, or environmental incentive mechanisms. We recognize that incorporating nondollar incentives with dollar-denominated incentives is difficult. Even if integration is not feasible, clarity is improved by showing the value of the incentives in units that can be easily compared to the main incentive. For example, a maximum service quality incentive may be stated as a percent rate increase or percent impact on earnings.

On Balance, the Sample Plans Show Only Modest Improvements Over the Status Quo

We developed an index that describes the overall power of a PBR to promote cost (resource) efficiency. We call this the LBNL power index. Most of the sample PBR plans show modest improvements over the status quo, but none approach the incentive power of a benchmark, generic utility subject to significant regulatory lag (a 5-year rate freeze and no fuel adjustment clause). Of all the implemented plans, CMP's has the highest score. Two PBR plans suffer because their plans have considerable pass-throughs (SDG&E) or low marginal sharing rates (NMPC). Our results indicate that, before adopting PBR, regulators and utilities should consider the regulatory status quo and decide whether PBR is a true improvement. If it is, then one should consider whether COS/ROR with increased regulatory lag would actually be better. PBR, by generally relying on external benchmarks, can be more responsive to changing conditions than COS/ROR with regulatory lag. In particular, it may be better at responding to external changes in fuel prices than would our generic utility with high regulatory lag but no FAC. PBR does, however, add complexity to the regulatory process.

Revenue Caps Are More Consistent With Policies to Promote DSM but Create Allocative Efficiency Problems That Require Mitigation

We confirm what is by now common knowledge for many industry participants: price caps provide a strong incentive to promote marginal sales and this dampens utility interest in DSM. Revenue caps provide the same cost minimization incentives as price caps but, in contrast, do not provide the same incentive to market electricity. While improving utility incentives with respect to DSM, revenue caps provide incentives for pricing (allocative) inefficiency. Under certain conditions, a utility will have an incentive to significantly raise price and reduce demand as a way to meet the revenue cap. It will be efficient in terms of cost but will cause reductions in overall welfare due to its pricing decisions.

Rather than dismiss revenue caps, however, we believe that it is possible for the regulator and utility to devise a hybrid price-revenue PBR mechanism that does not create allocative distortions and does not provide strong disincentives for DSM. Our hybrid cap is a linear combination of a revenue and price cap. It may be thought of as a revenue cap that penalizes the utility for raising prices *or* as a price cap that penalizes the utility for raising revenues. In fact, we see implicit hybrid caps operating in practice. The SDG&E plan and SCE proposal are both revenue caps that have supplemental rate incentives. Although rarely stated as a unified index, the two mechanisms have similarities to our proposed hybrid cap.

Most of our analysis of revenue caps assumes that the utility is a monopolist. In fact, electric utilities are fast losing their monopoly status in the generation segment of the industry. If competition is applied to the retail level and direct access is made available, then we suggest that the generation PBR incorporate price caps, rather than revenue caps, during the transition to price deregulation. Hybrid caps could also be considered, but the price cap weight will have to be very high due to the importance of price in emerging competitive markets.

In Generation Segment, PBR Appears Most Appropriate under Wholesale Competition and the Transition to Retail Competition

There are good reasons why COS/ROR, combined with IRP, is an appropriate form of regulation for long-term resource acquisition for vertically integrated utilities. The generation segment of the industry is, however, quickly moving to wholesale competition and may move on to retail competition. PBR is well-suited for both: as a permanent replacement to COS/ROR under wholesale competition and as a transition to price deregulation under retail competition.

Despite its increased value in a restructured industry, PBR is at risk for being swamped by the restructuring process. Much of the current debate is over stranded asset determination and allocation. We, however, do not believe PBR needs to await completion of industry restructuring. Consistent with all the major models of restructuring, we recommend that utilities either functionally or structurally separate generation from T&D and that separate but complimentary PBR mechanisms be adopted for generation and T&D. Stranded assets may also be subject to PBR so long as its index reflects the semi-sunk nature of stranded costs and is not based on indices of ongoing operating costs.

If Wholesale Competition Is the Ultimate Model, DSM and Environmental Goals May Be Built into the PBR Mechanism

If wholesale competition is recognized to be the ultimate industry model, it should be possible to develop PBR mechanisms that, in addition to the utility's private costs, include environmental costs and benefits and the costs and benefits to customers of DSM programs. We recommend that the overall incentive mechanism, including its DSM and environmental aspects, be stated clearly, so that the regulator and its customers are clear how the relative objectives are being traded off. NMPC's Merit index, which includes customer DSM expenditures and benefits of both the utility and its customers, demonstrates the feasibility of total resource or societal-type indices.

If Retail Competition Is the Ultimate Model, DSM and Environmental Goals Should Be Unbundled or Addressed Separately

If retail competition is perceived to be the ultimate model, the utility no longer has planning responsibility for the resource portfolio of its customers. Customer choice will be based primarily on private costs and service quality; thus, any social program that moves utility prices away from costs will not be tolerated. For environmental goals, the best solution is to pursue national or regional taxes, tradeable permits, or fee-rebates. These mechanisms would internalize environmental costs. For DSM, the best solution is for the utility to focus on programs that do not cause price impacts. Load management and market transformation programs do this, as well as energy service charges, which charge participants (beneficiaries) for program costs. Environmental and DSM objectives may also be achieved by collecting revenues from a less competitive industry segment, such as the T&D system. Such revenues could then fund DSM, environmental, or other social programs.

6.1 Concluding Thoughts

On balance we find PBR to be a promising alternative to COS/ROR but cannot call it a clear "winner." As is indicated by our summary above there are many potential pitfalls and unanswered questions regarding PBR's ultimate effectiveness. We believe, however, that the electric industry's transition to new industry structures will be facilitated by an understanding of the strengths and weaknesses of PBR plans that have been adopted or proposed by "pioneer" utilities. This report, by reviewing 11 such plans, makes one step in facilitating this transition.

Perhaps the greatest challenge for utilities will be determining which services it offers are now competitive or will soon be competitive. It will be difficult for formerly monopoly utilities to determine whether they can truly serve clients at competitive prices or if their likely success in a competitive market is solely due to their monopoly market power in related markets. A utility can expect that its monopoly services will eventually be unbundled and, as a result, its early advantage in competitive markets may erode. Once a utility has chosen its competitive markets, it must push for regulation that matches its business: detariffing of competitive services and regulation of monopoly services that is not overly complex but fair enough to make them immune from claims of anticompetitive behavior.

For regulators, the greatest challenge is to facilitate an effective transition to new industry structures. For services that are now competitive, regulators should end price regulation and make sure that access to remaining monopoly services are available on an open access basis at fair, nondiscriminatory prices. Although its potential pitfalls should be kept in mind, PBR should be considered as the mode of regulation for monopoly services and, possibly, as a transitional pricing mechanism on competitive services. Regulators must also address the utility's role in providing services not provided by competitive markets, such as DSM, low income assistance, and improved environmental quality. So long as the regulators' objectives in these areas are clear, they can craft regulation that balances those goals with customer and utility welfare.

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