Six Useful Observations for Designers of PBR Plans

This analysis of performance-based regulation (PBR) analyzes nine PBR plans implemented or proposed by "early-adopting" U.S. electric utilities. Its principal finding is that, unless PBR plans are aggressive through their setting of minimum terms, deadbands, and productivity offsets, PBR may be no better than existing cost-of-service/rate-of-return regulation.

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As has been well documented in these pages, the U.S. electric utility industry is undergoing a major restructuring. Its generation segment is experiencing reduced entry restrictions and relaxation of price regulation. Competition is increasing on the retail side of the electric industry as well, as a result of self generation, energy efficiency and, in the future, retail wheeling. The outcome of these increased competitive pressures is uncertain but they are causing regulators and utilities to call for reform of regulation on the remaining monopoly functions, which include transmission, distribution and supply to the captive customers of the local electric utility. 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, competitive, and partially competitive services. An important compensating incentive of COS/ROR is the fact that rate cases are conducted infrequently; depending on its length, the consequent delay—called regulatory lag—does provide some incentive to the utility to minimize cost.

Nevertheless, regulators and utilities are considering performance-based ratemaking (PBR) of monopoly and partially competitive utility services as a replacement for the COS/ROR approach.[1] If properly structured, PBR strengthens a utility's financial incentives to lower rates or costs relative to traditional regulation by weakening 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 transmission and distribution companies, water companies and airports. In the U.S., comprehensive incentive regulation has made the greatest inroads in the telecommunications industry. For electric utilities, most rate incentives previously have been limited to those that target fuel purchases or performance of individual power plants. However, recent proposals have been made for the comprehensive incentive regulation of U.S. electric utilities.[2]

I. Six Useful Observations

During the last year, we conducted a detailed analysis of PBR for the electric industry. Our approach was to collect nine PBR plans that have been proposed or implemented in the U.S. (**Table 1**). Our sample includes five price cap plans and four revenue cap plans. Price cap plans cap weighted average prices of predefined groups or market baskets of services. Revenue cap plans cap some or all of a utility's authorized revenues and the utility is required to return to ratepayers any revenues in excess of the cap. Five of the plans in our sample have been adopted and four are in the proposal stage.[3] We compare and contrast the plans in terms of their approaches to minimum term (length of time utility agrees to stay out of rate case), indexing formulae, the existence and type of earnings-sharing mechanisms, and their overall incentive power. We also conducted a conceptual analysis of the incentive properties of revenue and price cap regulation in terms of its effects on utility-sponsored energy efficiency programs. We share our six most significant observations below.

No. 1: Regulatory Lag Increases Under PBR—Somewhat

One of the simplest but most powerful ways that PBR can increase the incentive for a utility to increase its 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 1). 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.[4] Thus, our sample indicates that PBR represents a modest improvement in regulatory lag compared to typical U.S. practice and the utilities' pre-PBR experience.

No. 2: PBR Indices Appear to Do Better than COS/ROR, But Don't Expect Telco-Style Productivity Gains

To improve the chance of keeping electric utilities out of rate cases and to ensure that a portion of the benefits of incentive regula-

Table 1: Sample of Electric Utility Performance-Based Regulation Plans

Company	Plan Type	Term[a] (years) w/ PBR	Term[a] (years) w/o PBR
1. Central Maine Power Co. (CMP)	Price Cap	5	3[b]
2. NY State Electric & Gas (NYSEG)	Price Cap	3	3[b]
3. Niagara Mohawk Power Co. (NMPC)	Price Cap (*P*)	5	3[b]
4. PacifiCorp	Price Cap	3	3
5. Tucson Electric Power (TEP)	Price Cap (freeze) (*P*)	5	n.k.
6. Consolidated Edison of New York	Revenue per Customer Cap	3	3[b]
7. Pacific Gas & Electric Co. (PG&E)	Base-Rate Revenue Cap (*P*)	6	3
8. San Diego Gas & Electric Co.	Base-Rate Revenue Cap	5	3
	Generation Price Cap	2	1
9. Southern California Edison (SCE)	T&D Revenue Cap (*P*)	6	3
	Generation Hybrid Cap (*P*)	8	1

a. Terms include the litigated base year plus the number of years subject to indexing.
b. Estimate
n.k. = Not known; *P* = proposed

tion flows to customers, PBR plans usually rely on external indexing of rates or revenues. Most indices use an inflation index and adjust it annually using a preset productivity offset. The most widely-known formula is the "consumer price index (CPI) minus X formula" that has been proposed for price cap regulation in both the U.S. and U.K.[5] Inflation indices and productivity offsets (X factors) should be evaluated jointly because their combined effect determines the overall aggressiveness of the PBR mechanism. To better understand the overall aggressiveness of the plans' indices, we analyzed index performance by comparing historical growth in average prices or revenues per customer to growth that would have been allowed if the proposed index were in place during the historical period (**Table 2**). We used an eight-year historical period (mid-1984 to mid-1992) and computed the ratio of last-year to first-year index values.[6] This ratio is equivalent to the cumulative growth allowed over the period. For example, NMPC's historical ratio is 1.49, which means that rates were allowed to grow 49 percent during the historical period. However, NMPC's rates, if they had been indexed using the formula *proposed* by NMPC, would have grown by a factor of 1.33. Also shown in Table 2 is an indication of the type of inflation index used and the productivity offset chosen.

Table 2: Basis of PBR Price and Revenue Cap Indices and Comparison to Historical Performance

Company	PBR Plan Inflation Index	Productivity Offset (%/yr)	Cumulative Change in Index Value, 1984-1992 (CPI = 1.35)		
			Historical	PBR	Difference
Price Cap Plans					
NMPC	CPI	0.2	1.49	1.33	***-16%***
CMP	60% to 100% of GDP-IDP	0.5 to 1.0	1.38	1.23	***-15%***
PG&E (LEMC)	PPI for electric power	0.5	1.12	1.04	***-8%***
Pacificorp	Custom input price index	1.4[a]	1.20	1.10	***-10%***
Revenue Cap Plans			*(Index Values per Customer)*		
SCE	CPI	1.4	1.16	1.14	***-2%***
ConEd	No index specified		1.15	1.00	***-15%***
PG&E (non-LEMC)	CPI	1.2	2.23	1.25	***-98%***
SDG&E	Input price index, fossil plant cost index, CPI	-4.2 to 0.9	1.01	1.15	***+14%***

a. First-year value; offset updated annually

LEMC = Large Electric Manufacturing Class; GDP-IPD = Gross domestic product-implicit price deflator; PPI = Producer price index; CPI = Consumer price index

Although our analysis considers the situation where the prospective index is hypothetically applied to a historical period, it generally indicates that PBR plans would keep rates or revenues per customer below what COS/ROR would have provided. Table 2 shows that all the PBR indices would have lowered rates or revenues per customer except for SDG&E's index.[7] Also, all the plan indices beat the CPI, which grew 35 percent during the period.

Table 2 shows that most of the productivity offsets in our sample of U.S. electric PBR plans are in the range of 0.2 to 1.4 percent/year, although the component of SDG&E's index that computes distribution network expenditures has an implicit productivity offset of *negative* 4.2 percent/year.[8] These offsets are modest compared to the productivity offsets adopted in telecommunications incentive regulation, which are often in the range of positive three to five percent per year. The U.S. electric PBR productivity offsets are also considerably less than those recently adopted by the U.K.'s electricity regulator. The electricity regulatory in the U.K. has raised productivity offsets from -1.0 percent/year to 3.0 percent/year since price cap regulation began and has recently made some steep one-time adjustments for the 1995 and 1996 index years (**Table 3**).[9] The U.K. experience does not directly translate to the U.S. experience, most notably be-

Table 3: Average Electric Distribution Company Productivity Offsets as Adopted by the U.K. Electricity Regulator

PBR Year	1st Period	2nd Period (Adopted Aug. '94)	2nd Period (Revised Jul. '95)
1990-1994	-1.0%/yr		
1995		+14.0	
1996		+ 2.0	+11.5
1997-1999		+ 2.0	+3.0

Note: A positive value of X implies real decreases in distribution company prices

cause, in the pre-PBR period, U.K. utilities were government-owned, and may not have had prices that accurately reflected costs.[10] Nevertheless, recent U.K. experience shows that company behavior under incentive regulation may be very different from what was expected. U.S. regulators would be wise to consider seriously adopting aggressive X factors before embarking on PBR. Aggressive X factors are the best way to ensure that customers get a share of the productivity improvements that PBR may bring about.

No. 3: 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. Earnings-sharing mechanisms are popular: seven of the nine sample plans have some sort of sharing mechanisms. In **Figure 1**, the light solid color indicates that shareholders keep 75 percent or more of any earnings deviations and the dark solid color 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 review of the PBR plan (indicated by "A" and "O"). If no upper or lower earnings boundary is specified in the PBR, we indicate the lack of explicit boundaries with a "U."

Despite its popularity, earnings sharing represents 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 earnings variations around the benchmark return. We believe that deadbands are consistent with the standard economic theory of incentive regulation which says that the utility will have the optimal incentive to be efficient if it keeps 100 percent of any productivity-improving behavior. Consistent with such a theory, sharing should only occur to mitigate extraordinarily high or low earnings that cause the plan to become nonviable. PG&E's, Southern California Edison's, and Central Maine Power's earnings-sharing mechanisms are good examples of mechanisms that fit this model. PacifiCorp's and Tucson

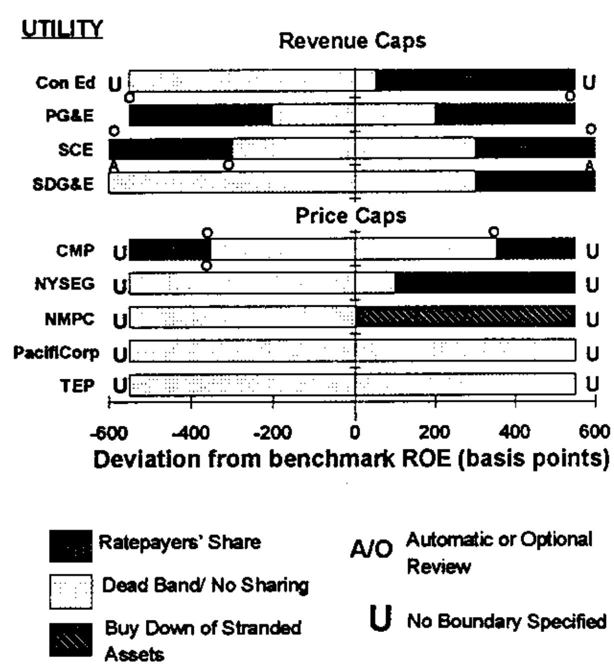


Figure 1: Comparison of PBR Earnings-Sharing Mechanisms (Note: For SCE and SDG&E, power mechanisms are specified in rate of return and have been converted to return on equity assuming debt-to-equity ratio = 1.0)

Electric Power's (TEP's) plans also put the utility at risk for earnings variations but do not provide for any sharing zones that might help make their plans more robust to unexpected events.[11]

No. 4: Whether PBR Represents an Increase in Efficiency Incentives Depends on the Initial Regulatory Framework

We have already described the incentive properties of PBR plans by discussing their minimum commitment to term and the degree to which shareholders keep incremental profits of any productivity-improving action. We combine the dimensions of term and marginal incentive power into one index, which we call the LBNL Incentive Power Index. A utility will score high on the index by having a long PBR minimum term, having no earnings-sharing mechanism, or having an earnings-sharing mechanism with a wide deadband. In **Figure 2**, we compute the LBNL Power Index for each utility both with and without PBR, and for 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 because we believe they are representative of the typical range of practice that exists under U.S. COS/ROR regulation.

Compared to the status quo, we find that most PBR plans in our sample represent an improvement in overall efficiency and represent an improvement compared to Generic Utility No. 2. Few utilities have index scores that come close to Generic Utility No. 1's score, however.

The highest-powered PBR plan that has been *implemented* is CMP's. Its high score comes from a wide sharing deadband (as was shown in Figure 1), its comprehensive scope, and its five-year term. On a relative basis, CMP, PG&E's, 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 public utility commissions 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 should be better at responding to external changes in fuel prices than would Generic Utility No. 1, which relies simply on regulatory lag. PBR does, however, add complexity to the regulatory process. Thus, a key question for utilities and regulators is whether the added complexity of PBR is worthwhile in terms of its ability to keep a utility out of rate cases.

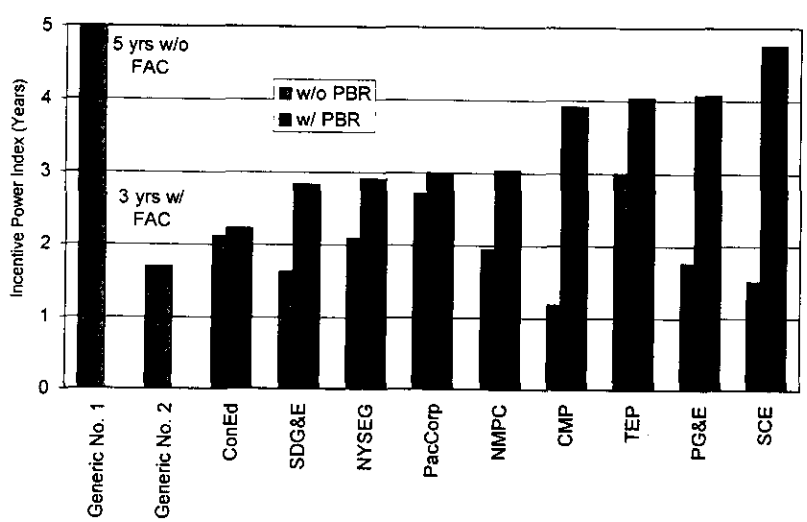


Figure 2: LBNL Incentive Power Index

No. 5: Multiple Incentives Are O.K., but Their Relationships Should be Made Clear

Many of the PBR mechanisms in our sample actually consist of two or more incentive mechanisms. Seven of the nine plans have supplemental incentive mechanisms for service quality. Also, three of the four revenue cap plans have supplemental rate incentives. From a theoretical point of view there is nothing wrong with multiple incentive mechanisms per se. Multiple mechanisms may be thought of as components of an overall index from which company performance may be compared. In fact, multiple incentive mechanisms may be necessary in the electricity industry in light of restructuring. Because of growing competition and likely service unbundling, it may well be necessary to have one PBR mechanism governing transmission and distribution (T&D) service and another governing generation service. Multiple mechanisms may be subject to different benchmarks, different levels or pricing flexibility, and different time horizons.

A case in point of multiple PBRs exists for generation service vis à vis transmission and distribution (T&D) services. Given that the electric generation market is more likely to undergo a transition to competition than is the market for T&D services, it is reasonable to expect that a generation PBR would rely more on market data, allow for greater pricing flexibility, and be more transitory in nature than would a T&D PBR. Any PBR that did not have separate components for generation and T&D would have to be modified if, at a later time, an electric utility were restructured into separate business units or companies.

Multiple incentive mechanisms do create problems, however, when their relationship is unclear or if they put the utility at substantially different levels of risk. PBRs that protect shareholders from de-

viations in fuel price changes more than changes in base-rate costs can lead to utilities that try to beat the PBR index by undercapitalizing their facilities and overspending on fuel. This is because a dollar saved on non-fuel costs adds more to the bottom line than a dollar saved on fuel costs. Our impression of our sample of early-adopting utilities was that they did not give enough consideration or disclosure of the relationship of the multiple mechanisms that made up their overall PBR plan.

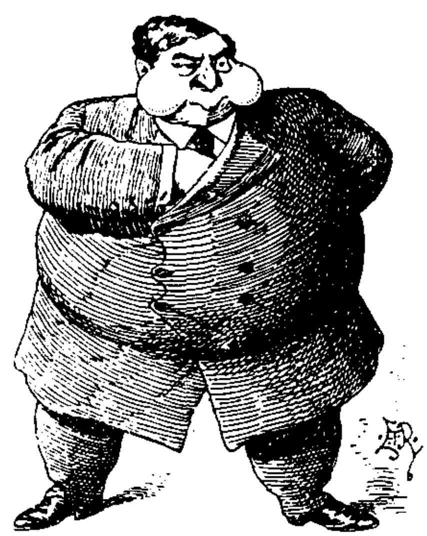
No. 6: Revenue Caps Help Reduce the Incentive to Market Power but Create Incentives for Distorted Pricing

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). Revenue caps or revenue-per-customer caps have been proposed as a way to introduce incentive regulation without creating the disincentive to pursue DSM. There is a straightforward parallel between the pros and cons of price and revenue caps and the pros and cons of the ratepayer impact measure (RIM) and the utility cost (UC) test.[12] A rational utility subject to a price cap will use the RIM test as a criterion when considering whether or not to pursue DSM. A utility subject to a revenue cap will use the UC test. For those wishing to keep a utility active in the provision of cost-effective DSM, the advantages of a revenue cap over a price cap are clear. We analyzed the incentive of the utility to minimize its own internal costs under revenue and price cap plans and found them to be the same. This good news is tempered, however, by our finding that revenue caps create troublesome pricing incentives. We confirm and expand upon a result, recently presented in the academic literature, that revenue caps give utilities a strong incentive to act like monopolists.[13] If a utility is held only to a revenue cap, it has an incentive to raise prices, reduce output, and receive profits in excess of its cost of capital. This incentive is exacerbated when demand for services is elastic, as would be the case in partially competitive markets such as electric supply.

As a practical matter, any utility subject to a revenue cap would probably find it difficult to significantly raise prices under the cap; we believe that most regulators that adopt revenue cap regulation would also enforce a cap on prices if the utility tried to raise them. Because regulators are not all-powerful, however, we believe that it would be imprudent to leave the utility with such an incentive to pursue monopoly pricing under an incentive mechanism. Price caps may be the best solution for services that are partially competitive or are becoming increasingly competitive. Thus, price cap regulation may be best for PBR that covers generation services, which is generally agreed to no longer be a monopoly. Because of their monopoly status and because many regulators wish utilities to retain a role in the provision of DSM, we do not recommend pure price caps for transmission and distribution (T&D) utility services. Instead, we suggest a combination, or hybrid, of price and revenue caps. A hybrid cap could have the following form:

$$R \leq \bar{R} - b \times P$$

where R is a utility's actual revenues, $\bar{R}$ is its nominal revenue cap, and $b \times P$ is a penalty factor applied if the utility increases its prices (P). The proper choice of the price penalty weight, b, depends on a utility's starting prices and revenues and the estimated elasticity of demand and the degree to which the regulator wants to penalize the distribution utility for marketing electricity. Although we developed our hybrid



cap based on a conceptual analysis, 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 and making sure the utility chooses prices that increase rather than decrease welfare to customers. We believe our hybrid cap has the added advantage that it is transparent. As noted in Observation No. 5, we found the relationship of multiple incentives to be poorly presented in most PBR plans. Supplemental rate incentives tacked onto a revenue cap (or alternatively, a revenue or bill index tacked onto a price cap) do not immediately show the relative importance of each mechanism. A hybrid cap would naturally make the relationship of the combined revenue and price caps clear.

II. Conclusion

The PBR plans in our sample of early-adopting electric utilities are hampered by the relatively short minimum 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. As is well shown in Observation No. 4, 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. Thus, we believe that it is an open question whether PBR as proposed and implemented by our sample represents an improvement over COS/ROR regulation.

We also believe that the appropriate way to integrate DSM into PBR has yet to be carefully thought out. Due to growing competition and unbundling, it is likely that generation PBR will be separate from T&D PBR and generation PBR may be more transitory in nature. The focus of utility incentives for DSM should be on the T&D portion of the electric utility and any PBR's impact on a utility's incentive to pursue DSM should be carefully considered. We suggest a hybrid cap as a transparent way to mitigate the disincentive to pursue DSM while not promoting monopoly pricing of T&D services.

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

Endnotes:

1. The research highlights presented in this paper come from G. A.COMNES, S. STOFT, N. GREENE, AND L. HILL, PERFORMANCE-BASED RATEMAKING FOR ELECTRIC UTILITIES: REVIEW OF PLANS AND ANALYSIS OF ECONOMIC AND RESOURCE PLANNING ISSUES (Lawrence Berkeley Laboratory, LBL37577, Nov. 1995) and L. HILL, A PRIMER ON INCENTIVE REGULATION FOR ELECTRIC UTILITIES (Oak Ridge Nat'l Laboratory, ORNL/CON422, Oct. 1995). Both reports were funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Office of Utility Technology, Office of Energy Management Division of the U.S. Department of Energy. The views and opinions expressed in the article are solely those of the authors and not those of the U.S. DOE, LBNL, ORNL, or MRW & Associates, Inc.

See also Tim Woolf and Julie Michaels, *Performance-Based Ratemaking in a Competitive Electricity Industry*, ELEC. J., Oct. 1995, at 64.

2. *See* Martin N. Lowry, *The Case for Indexed Price Caps for U.S. Electric Utilities*, ELEC. J., Oct. 1991, at 30.

3. Our understanding is the Niagara Mohawk Power Corp. (NMPC) and Pacific Gas & Electric Co. (PG&E) proposals have been effectively withdrawn and will be replaced with revised proposals. We keep these proposals in the sample because we believe they still are interesting to analyze and provide guidance to utilities and regulators considering PBR.

4. J. ETO, S. STOFT, AND T. BELDEN, THE THEORY AND PRACTICE OF DECOUPLING 11-12 (Lawrence Berkeley Laboratory, LBL34555, Jan. 1994).

5. In the U.K., the commonly used price (inflation) index is known as the retail price index (RPI).

6. For revenue cap indices, we normalized values to the number of customers. Doing so gives an indication of how well the PBR would have performed relative to the indexed portion of customer bills and allows us to compare the normalized index to growth in the CPI. In the case of ConEd, its revenue cap is expressly revenue per customer, so no normalization is necessary. The other revenue cap plans all have customer growth components to their index, but are not simple revenue-per-customer caps like ConEd's.

7. PG&E's historical performance appears very poor, most likely due to the introduction of its Diablo Canyon nuclear generating station, which caused rates to increase generally and a shift from fuel to non-fuel revenues. Figure 1 shows only the non-fuel portion of revenues because that is the portion that is indexed under PG&E's plan.

8. SDG&E's indexed gross network additions are adjusted to a value net of replacements and are then subject to traditional ratemaking (i.e., computation of return, depreciation, and taxes) to compute annual revenue requirements.

9. Data for Table 3 is taken from *The Economist*, Jan 28, 1995, and U.K. Office of Electricity Regulation (OFFER), The Distribution Price Control: Revised Proposals (July 1995).

10. For a detailed description of price cap regulation in the U.K., *see* M. ARMSTRONG, S. COWAN, AND J. VICKERS, REGULATORY REFORM: ECONOMIC ANALYSIS AND BRITISH EXPERIENCE (MIT Press, 1994).

11. NMPC's proposed earnings-sharing mechanism is somewhat different the others in the sample. NMPC proposes to keep only 50 percent of earnings above the benchmark; the rest go toward buying down "regulatory assets." (This different type of sharing is indicated with a hatch-marked pattern in Figure 2.) Regulatory assets include items such as above-market purchase power obligations that are potentially strandable.

12. For definitions of the DSM benefit-cost tests and an introduction to the debate that surrounds their use, *see* J. Deegan, *The TRC and RIM Tests, How They Got that Way, and When to Apply Them*, ELEC. J., Nov. 1993, at 41; and J. Chamberlin, P. Herman, and G. Wikler, *Mitigating Rate Impacts of DSM Programs*, ELEC. J., Nov. 1993, at 46.

13. M.A. Crew and P. R. Kleindorfer, *Price Caps and Revenue Caps: Incentives and Disincentives for Efficiency*, in PROCEEDINGS: EIGHTH ANNUAL ADVANCED SEMINAR ON PUBLIC UTILITY REGULATION (Western Conference, San Diego, July 1995).