Making Performance-Based Ratemaking Consistent with Market Transformation

Paul A. Centolella, Science Applications International Corporation

Utilities and regulators are considering price caps and other forms of performance-based ratemaking to encourage cost savings and provide pricing flexibility. Price caps create an incentive to maximize sales at any price above marginal cost. Even with the addition of a lost revenue adjustment, price caps may undermine utility support of efficiency programs designed to produce market transformation impacts that cannot be readily quantified.

Some analysts have proposed revenue caps. Unfortunately, a simple revenue cap could prompt the utility to raise prices, staying within its cap by reducing consumption. Utilities should be encouraged to make economic sales when prices are above societal marginal costs.

This paper mathematically describes and discusses the advantages of a modified price cap that resolves this conflict. Under the modified cap, recovery of fixed costs in excess of short-run marginal costs would be adjusted based upon expected sales. Expected sales would be determined after the rate year based on a backcast of a previously approved statistical model and model inputs reflecting actual prices and conditions during the rate year. The price cap would be adjusted to allow recovery of the difference between fixed cost revenues at expected and actual sales levels. Additionally, the modified price cap approach incorporates an after-the-fact reconciliation of potentially stranded costs. This approach rewards the utility for increasing economic sales and avoiding inefficient energy use.

INTRODUCTION

The electric power industry is entering a transition, that could last several years, in which performance-based regulation (PBR) will receive increasing attention. A transition to competition is necessary to allow many utilities to recover embedded generation costs that are in excess of market prices, potentially ''stranded'' costs. In a fully deregulated electric power industry, policies to promote energy efficiency may require entirely new institutions and competitive approaches to market transformation (Centolella 1994, 1995b). This paper addresses the more immediate issue of utility support for energy efficiency market transformation programs during a transition to retail competition. It identifies potential economic disincentives to utility support of energy efficiency under price cap regulation and proposes a modified price cap that minimizes such disincentives, while retaining the primary benefits of price cap regulation. The paper begins with brief discussions of energy efficiency market transformation programs, the limits of traditional cost-of-service regulation, and approaches to PBR. Next, the paper describes potential disincentives to utility support of energy efficiency under price cap regulation, including those issues that are unique to market transformation. Finally, we identify steps for minimizing or removing these disincentives and mathematically describe a modified price cap which could reconcile the potential conflict between PBR and market transformation programs.

MARKET TRANSFORMATION PROGRAMS

There has been increasing interest in initiatives designed to transform markets for energy-efficient products and services. Market transformation differs from conventional utility demand-side management (DSM) in that it is designed to cause changes in the structure of the market for energy efficiency products or services (e.g., new players, products, practices, or prices), or in the behavior of market participants. Market transformation programs create:

- A lasting change so that the targeted efficiency measure continues to be adopted without ongoing program intervention; and
- Spillover benefits such that there is a secondary adoption of efficiency measures as a result of the program, including the adoption of targeted efficiency measures by consumers who are not direct program participants.

Market transformation programs are frequently designed to accelerate the commercialization of successively more efficient products and practices by reducing or offsetting market failures. Economists have identified two categories of market failures related to consumer evaluation of energy efficiency investments. (EIA 1996; Levine et al. 1994).

- *Information Asymmetries:* Energy use as a ''hidden'' attribute of a large number of products and services. As a result, many consumers remain poorly informed regarding costs, technology, and their own behavior-related energy efficiency choices.

- *Bounded rationality:* Evaluating energy efficiency measures can require solving complex optimization problems. Neoclassical economics assumes that each market participant can readily gather and use the information necessary to make efficient decisions. In reality, when making unfamiliar choices, consumers tend to repeat prior purchasing patterns and avoid optimal choices that have higher first costs.

Such market failures may disproportionately impact the acceptance of new technology. Additionally, the development of new technologies may be retarded by:

- *Non-Rival Use and Imperfect Exclusion:* Reverse engineering may allow competitors of the original developer to capture part of the benefits resulting from the development of new technologies.

As a result, some products that would be economically attractive are not developed and utilized.

The implementation of Model Conservation Standards in the Pacific Northwest, the Western Utilities Consortium refrigerator programs, followed by the Super-Efficient Refrigerator Program, and the initiatives of the Consortium for Energy Efficiency are examples of market transformation programs.

LIMITATIONS OF COST-OF-SERVICE REGULATION: THE CASE FOR PBR

The goal of price regulation has been to protect the public interest by maximizing consumer welfare, subject to the constraint of the utility's opportunity to earn a reasonable return. Better systems of price regulation attempt to satisfy at least the following objectives:

(1) *Cost Minimization:* The regulated firm should seek to provide the electric energy services demanded by its customers at the minimum total cost in the short run and the long run.

(2) *Bill Minimization:* Over time, consumers should pay no more on average than the minimum cost of supplying the electric energy services they demand.

(3) *Accurate Price Signals:* Prices should reflect prevailing supply and demand conditions at each point in time and location on the transmission network, thus reflecting the marginal cost of supplying electricity, giving the utility's customers the incentive to make efficient consumption decisions.

Policymakers also consider other distributional and political objectives, including: consumer risk preferences and expectations that rates will be simple and predictable, the need to minimize regulatory costs, and the subjective notions of equity advanced by various parties.

Cost-of-service regulation is an inherently imperfect substitute for competitive markets. Regulators face a problem of agent (utility) / principal (regulators and consumers) relationships, in which utilities have superior access to information. (Crew & Frierman 1991; Joskow & Schmalensee 1986). Regulators can never know as much about the utility's business as utility managers. In particular, regulators seldom are able to directly observe the economic cost functions of the regulated firm. While detailed data is gathered on accounting costs, regulators have a difficult time determining the marginal benefits (or costs) of spending more (or less) on labor, capital investment, or other inputs. While integrated resource planning (IRP) has helped address these questions, IRP proceedings cover resource planning only at a general level. Moreover, regulation may create incentives for utilities to shape or manipulate the cost data presented to regulators. Although regulation has reduced prices relative to what a monopolist would charge, given an exclusive legal franchise, the results of price regulation in U.S. regulated industries have differed substantially from the public interest ideal of an economically efficient substitute for markets. (Joskow & Rose 1989).

One approach to reducing the imperfections of price regulation is to reward the utility for acting so as to reveal its efficient cost for providing electric energy services. The effort to create such incentives is the basis for development of comprehensive PBR. Comprehensive PBR offers advantages for regulating the price of bundled utility services:

- *PBR can increase economic incentives to minimize costs.* Cost-of-service regulation is not cost plus regulation. Regulatory lag is built into the ratemaking process and forces utilities to live with set rates between one rate case and the next, providing an incentive to minimize costs. However, such incentives may be limited by rate adjustment clauses, the use of future test years, the option to file more frequent rate cases, and utilities' ability to time rate cases to match the in-service dates of major investments. Moreover, cost-of-service regulation may distort utility choices. For example, in a cost-of-service regulatory process, large capital investments have attracted greater attention and a higher probability of disallowance. By extending the period of regulatory lag and reducing differences in the ratemaking treatment of resource inputs, PBR can encourage the utility to reduce costs. The resulting disclosure of the utility's capacity for cost reduction may benefit consumers through sharing mechanisms or in future PBR periods.

- *PBR offers utilities greater pricing flexibility.* Traditionally, rates have been fixed on an average cost basis. They do not reflect hourly changes in market prices and for many utilities are well above marginal costs. In some cases, cost allocation practices have incorporated significant cross-subsidies between customer classes. Under PBR, utilities will have the ability to expand access to real-time pricing on an economic basis and to develop two-part tariffs. Two-part tariffs include a lower marginal energy rate, accompanied by an access, initial rate block, customer or demand charge for recovering fixed costs in excess of short-run marginal costs. Such two-part tariffs can benefit the utility by increasing sales and can increase consumer surplus by allowing consumers to make additional purchases under a marginal energy charge that is below historic rates, but at or above marginal cost. PBR proposals also may provide the utility the flexibility to phase out cross-class subsidies.

- *PBR imposes a form of cost discipline that is comparable to that faced by price-taking firms in competitive markets.* It prepares the utility to face the challenge of competition by reducing its costs and marketing new services, while reducing the resources that the utility is required to devote to regulatory proceedings.

- *PBR can facilitate the introduction of competitive services.* Implicit in PBR is an allocation of utility common costs between regulated and unregulated services. Consumers of the regulated service can only be charged for prices allowed by the PBR mechanism.

Some utilities and regulators are looking at PBR as a mechanism for recovering potentially stranded costs. PBR can perpetuate rate regulation during a period when average embedded costs exceed market prices, while providing pricing flexibility to increase revenue growth.

PERFORMANCE-BASED REGULATION: AN OVERVIEW

Performance-based regulation is the practice of structuring rates so as to provide the regulated utility an economic incentive to reduce costs or achieve other regulatory objectives. Comprehensive PBR places a limit on prices or revenues in the form of a price cap, a revenue cap, or a modified price cap. PBR creates an incentive for cost reduction by suspending the linkage between rates and current costs and extending the period of regulatory lag for a predetermined number of years by linking prices and/or fixed-cost revenues to an external index.

Comprehensive PBR has its roots in the ''sliding scale'' plans, sharing profits or losses above or below a target return, that were first employed in England in the 19th century. They allow the utility to retain a share of the cost savings resulting from efficiency improvements. Common PBR systems can be defined based on a sharing formula:

$$P_t = C_t^* + g(C_t - C_t^*)$$

where:

P_t = The average levels of rates in period ''*t*.''
C_t^* = An expected or target unit cost of production for period ''*t*'' as approved by regulators. The target unit cost could be determined as a function of input prices, quantity, and expected productivity changes over time.
g = A constant between zero and one representing the fraction of costs above the target level that would be borne by ratepayers and the fraction of cost savings below the target level that will be distributed to ratepayers.
C_t = The utility's actual cost per unit in period ''*t*.''

A simplified version of this formula was proposed by Baumol (1982) and has become the basis for most price cap proposals. The common price cap formulation contains four modifications to the general equation:

- Target unit costs for future periods are indexed to a price index, such as the consumer price index (CPI) and a factor (X) representing expected improvements in total factor productivity in excess of those incorporated implicitly in the selected price index. Prices are pegged to indices for the industry as a whole, instead of specific cost functions for the individual utility.

- A factor (Z) has been added to allow the utility to recover uncontrollable and unforeseen costs.

- The price cap formula is often expressed as an inequality which caps an index of utility prices, but does not prevent the utility from lowering rates.

- The sharing of cost savings or costs above target levels with ratepayers may be eliminated (the constant, ''*g*,'' is set to zero) or addressed through a separate collar on profits.

The price cap formula is typically expressed as:

$$P_t \leq P_0(1 + \%\ change\ in\ CPI - X) + Z$$

where:

- P_t = An index of the utility's prices in period ''t'';
- P_0 = An index of the utility's prices in a base period ''0'';
- CPI = A specified inflation index such as the Consumer Price Index;
- X = An assumed rate of productivity improvement in excess of that implicit in the selected price index; and
- Z = An adjustment for costs outside of the utility's control (e.g., the revenue requirement impact of new taxes or environmental legislation).

In their implementation, price cap formulas can become considerably more complex with different service classifications or customer groups divided into separate market baskets with individual price limitations to restrict cost shifting from one group of customers to another.

Price caps remain controversial in part because of the difficulty of defining an appropriate price index and selecting a reasonable level of expected productivity improvement.

Bringing largely sunk fixed costs within a price cap structure, which increases revenues in relationship to sales growth, can increase the extent to which price cap revenues depart over time from the underlying revenue requirements they are designed to recover. Some regulators have addressed both this problem and disincentives to DSM, by developing revenue caps covering a portion of the utility's revenue. Such revenue caps frequently exclude fuel and purchase power costs.

Crew and Kleindorfer (1995) and Comnes et al. (1995) have critiqued the concept of a revenue cap on grounds that, given highly elastic demand, a revenue cap could provide the utility an incentive to reduce revenues by increasing prices and, in particular, prices for price elastic services. The core of these critiques is that under conditions of short-run demand elasticity (or large efficiency programs) a utility could meet the revenue cap and increase profits by raising prices so as to reduce demand and thereby cut its variable costs. A necessary assumption of these critiques is that the revenue cap would be applied to recovery of the utility's variable costs. It is the inclusion of marginal operating costs within the revenue cap that produces any incentive to reduce sales. If allowed revenues under the revenue cap are adjusted to reflect the marginal costs or cost savings associated with changes in sales, or if costs which vary with sales are excluded from the cap, any incentive to increase price and reduce supply disappears.

PRICE CAPS AND DISINCENTIVES TO MARKET TRANSFORMATION

The disincentives in traditional ratemaking practices to utility implementation of energy efficiency programs are well understood. Traditional rate design has created rates in which tailblock energy prices exceed the utility's short-run marginal costs. As a result, utilities lose revenues for the recovery of their fixed costs or their profits—the residual component of fixed costs—whenever sales fail to grow as rapidly as might otherwise occur. This occurs regardless of whether sales are above or below test year levels. Within the context of cost-of-service regulation, regulators in most states have adopted reforms designed to mitigate these financial disincentives.

The combination of price caps and a transition to competitive power markets creates new disincentives for market transformation programs that are not easily addressed by conventional approaches. There are four key factors that could combine to create disincentives to a utility supporting market transformation programs, while subject to a price cap:

- *If included in the cap, price caps create an incentive to reduce expenditures on energy efficiency.* Price caps induce utilities to reduce their average costs per unit of production. The utility retains the difference between the cap and its costs per kWh sold. Efficiency expenditures can reduce sales and produce only a modest reduction in the utility's average costs per unit of energy sold. Because many of the benefits of efficiency programs flow to consumers and are external to the utility, efficiency expenditures can become a target for cost cutting.

- *Price caps create an incentive for the utility to increase sales whenever the rate charged exceeds the utility's short-run marginal costs, regardless of whether the sales are economic or could be displaced by a less costly energy efficiency measure.* In some price cap proposals, utilities have sought to address this concern by adding a net lost revenue adjustment. Such adjustments may address the direct effects of DSM programs, but are not effective in eliminating the disincentives to market transformation impacts. A net lost revenue adjustment is calculated by multiplying the utility's fixed cost margin—the difference between marginal energy charges and the utility's marginal costs—times the net loss of sales attributable to its efficiency programs. The utility must be able to prove in an open regulatory process the volume of lost sales. The spillover and lasting effects of a market transformation program are not linked directly to program participation and, therefore, are difficult to quantitatively attribute to a specific utility program. Thus, the utility retains an incentive to avoid market transformation impacts that cannot be directly tied to its programs.

- *Price caps extend regulatory lag, increasing the disincentive to market transformation programs.* When lower sales reduce the utility's ability to recover its fixed costs, under conventional regulation a utility can file a rate case. The rate case will reallocate the recovery of fixed costs and end the reduction in recovery of fixed costs associated with prior energy savings. Price caps block the utility from using the normal rate case cycle to limit revenue losses from market transformation effects for the duration of the cap.

- *A fixed duration price cap, followed by deregulation, can expose vertically integrated utilities to the effects of load reductions on the market price for power.* Significant efficiency programs will reduce demand and may lower competitive market prices for generation services. Efficiency improvements that materially lower market prices will extend the period that would be required to recover potentially stranded costs. If a price cap of fixed duration is utilized to provide the utility the opportunity to recover strandable costs, lower market prices will reduce the utility's ability to recover such costs.

These disincentives come into conflict with the traditional utility objective of helping customers to lower their energy costs; the utility's need to position itself for potential retail competition by becoming an effective provider of efficiency services; and the public policy objectives of reducing the cost of energy services, environmental impacts, and the market price of electricity.

PRICE CAP PLUS: REMOVING DISINCENTIVES TO UTILITY SUPPORT FOR MARKET TRANSFORMATION DURING THE TRANSITION PERIOD

A performance-based approach must reconcile the need to remove disincentives to Market transformation, while maintaining an incentive for the utility to reduce prices and make economically efficient energy sales. Achieving both these objectives can be difficult. For example, applying a revenue cap to all fixed costs could remove the revenue loss disincentives. However, a revenue cap on all fixed costs also would make the utility indifferent to lowering prices to make additional sales, because the recovery of fixed costs and the utility's profits would be fixed by the revenue cap, regardless of sales levels.

The financial disincentives to market transformation can be largely eliminated, and the benefits of PBR preserved, with a modified price cap that has three essential elements:

- Recovery of program costs outside of the price cap constraint;

- A statistical lost margin adjustment; and

- After-the-fact quantification of strandable costs that takes into consideration the effects of installed efficiency measures on market prices for generation services.

Such an approach can remove financial disincentives to installing efficiency measures during the period in which the utility is recovering potentially stranded costs.

Recovery of Program Costs Outside the Price Cap Constraint

The incentive for the utility to cut expenditures that do not facilitate increased sales can be addressed by placing the recovery of program costs outside the scope of the price cap constraint. Recovery of program costs could be included in the ''*Z*'' factor or a periodic rate adjustment. This approach is consistent with the current practices of many state commissions that periodically review and approve utility DSM budgets.

Statistical Lost Margin Adjustment

Market transformation effects are not directly linked to a consumer's participation in a utility program. Therefore, a lost revenue adjustment, which requires evidence of the link between the utility's program and a sales reduction, will not make a price cap revenue neutral. A straightforward modification of such adjustments can remove the revenue loss disincentive and may provide incentives for the utility to encourage economically efficient market transformation.

Net lost revenue adjustments are calculated by multiplying fixed cost margins by volumes of lost sales. The statistical lost margin adjustment changes the manner in which the volume of lost sales is determined. Instead of relying on engineering estimates or evaluations of DSM program effects, lost sales would be calculated as the difference between a statistically determined level of expected sales and actual utility sales. The calculated lost margin would be carried forward in a balancing account and used to adjust allowed prices in the following year.

Statistical models are widely accepted as a methodology for normalizing and forecasting utility sales. A statistical lost margin adjustment would apply comparable statistical models, but in a manner that avoids the problems associated with the current use of such models to forecast sales in ratemaking proceedings. A previously approved statistical model would be run after the end of each rate year to backcast expected sales given actual rate year conditions. Actual rate year data regarding utility prices, local economic conditions, weather, and population growth would be used in running the model.

In a conventional rate case, people argue over forecasting models and the forecasted inputs used in those models because each party can determine the effects of changing the model or model inputs on rates. To avoid such disputes and eliminate the possibility of gaming, the utility would have to obtain prior approval of the statistical algorithm in the proceeding initiating the price cap and of any updates prior to the rate year to which those updates would be applied. The model would be approved before the actual rate year and thus before model inputs are known. Therefore, no party would be able to determine at the time of model approval whether a particular change to the model would benefit its financial interests. The only incentive for the parties would be to develop a statistical model which matches as accurately as possible the historical relationships between sales and input variables. Moreover, unlike the use of forecasts in conventional rate cases, running the model after the rate year using actual data avoids the need to use forecasts of model inputs. Thus, the major sources of controversy regarding forecasting in rate cases are avoided in the proposed statistical rate adjustment.

When forecasting models are run after the fact with actual data, they typically are quite accurate in estimating actual sales. (Hirst 1993). Absolute accuracy in determining what sales would have been in the absence of utility efficiency programs, however, is not required. The mechanism provides a reasonable and efficient adjustment to growth in recovery of revenues in excess of marginal costs. It is not intended to provide dollar-for-dollar compensation for lost revenues attributable to the utility's efficiency programs. Because revenues in excess of short-run marginal costs are decoupled from actual sales and tied to statistically expected sales, the utility remains, at least, neutral with respect to the impact of market transformation on actual sales.

This approach creates financial incentives for the utility, both to reduce energy prices so as to encourage economic sales, and to promote energy efficiency when efficiency has significant economic benefits for its customers. Because actual energy prices are an input into the model of expected sales, the utility's allowed average prices (including access and customer charges) and revenues will increase when its actual energy charges decline. Thus, the approach encourages pricing flexibility and efficient two-part tariffs. Moreover, the use of indicators of local economic activity in the model used to calculate expected sales means that the utility's allowed prices and revenues can increase when the local economy improves. Thus, the utility can benefit by encouraging the adoption of energy efficiency measures that lower customer costs and increase local economic competitiveness.

The use of actual rate year conditions as model inputs may limit the magnitude of the required rate adjustments. The model can be specified so that the utility retains the risk of revenue variability associated with year-to-year changes in weather and economic activity. Because the adjustment can either increase or decrease rates, mechanisms that price adjustments by deferring revenues in excess of the cap also may be used to limit the amount of price increases attributable to annual variations in the statistical lost margin adjustment.

After-the-Fact Determination or Reconciliation of Strandable Costs

Utilities may be concerned that energy efficiency programs will reduce competitive market prices for generation and thereby increase their potential stranded cost problem. This concern can be addressed by a stranded cost recovery mechanism that takes into consideration the impact of efficiency measures on actual market prices. It is often assumed that strandable costs will be quantified through an administrative proceeding prior to deregulation. *Ex ante* quantification, however, requires solving difficult forecasting and modeling problems to estimate market prices given a new regulatory and market structure for generation. Quantification of strandable costs can be reconciled to actual market prices after recovery of such costs has begun. *Ex post* quantification involves the periodic adjustment of initial estimates of strandable costs based on actual market prices. An *ex post* approach is both analytically simpler and less likely to produce large windfall gains or losses. (Centolella 1995a). Regulators and financial markets may, in fact, prefer this less risky approach to quantification. *Ex ante* quantification may produce higher costs of capital reflecting increased business risks, and, if recovery occurs through PBR, may tend to reduce consumer surplus to the extent that PBR is designed to ensure a given cost recovery or reflects the utility's superior knowledge. (Schmalensee 1989).

PBR offers a straightforward option for the *ex post* quantification and recovery of potentially stranded costs by instituting a cap with an indefinite duration. The duration of the cap would be affected by observed market prices. The cap would continue until the present value of unrecovered potentially stranded costs (costs in excess of market prices) equals the present value of any projected economic profits (future market prices in excess of depreciated embedded costs). As competitive forward power markets develop and PBR provides an incentive for the utility to disclose its efficient costs, it will become easier to determine when to terminate the PBR mechanism because it has allowed full recovery of costs in excess of market prices.

Market transformation programs may affect the time required to recover potentially stranded costs through their potential impact on market prices. This impact in most cases should be small. The risk that future regulators could renege on allowing the recovery of such costs cannot be entirely eliminated and may be marginally increased by extending the transition period. Such risks, however, can be minimized by approving in advance the formula used to determine whether an extension of the PBR plan is necessary to permit full recovery.

The Structure of Price Cap Plus

For a simple case of one service classification, market basket, and volumetric rate, the limit on prices in each year under the modified price cap approach could be defined as follows:

$$P_t \leq P_{t-1} \times \left(\frac{CPI_t}{CPI_{t-1}} - X\right) + \frac{(P_{t-1} - V_{t-1}) \times (Q_{t-1e} - Q_{t-1}) \times (1 + I)}{Q_t} + Z$$

where

P_t = The allowed price under the price cap in period ‘‘t.’’
P_{t-1} = The allowed price in the preceding period ‘‘$t-1$.’’
CPI_t = The value of the selected price index for year ‘‘t.’’
CPI_{t-1} = The value of the selected price index for the preceding year ‘‘$t-1$.’’
X = The productivity improvement factor, based on expected improvements in firm productivity in excess of those implicit in the price index.
V_t = The utility’s short-run marginal costs for additional sales in period ‘‘t.’’
Q_{t-1e} = The utility’s expected sales in period ‘‘$t-1$’’ based on a backcast of expected sales levels developed from a pre-approved model for projecting sales. This model should consider impacts of actual prices, weather, economic, and other conditions during rate year ‘‘$t-1$.’’ The model should not, however, explicitly represent changes in the utility’s conservation programs, so as to preserve the utility’s net income neutrality with respect to those programs.
Q_{t-1} = The utility’s actual sales in period ‘‘$t-1$.’’
Q_t = The utility’s sales in rate year ‘‘t.’’
I = The carrying charge rate applied to the lost margin adjustment balancing account.
Z = An adjustment for costs outside of the utility’s control (e.g., the revenue requirement impact of new taxes or environmental legislation), balances in the utility’s lost margin balancing account as a result of changes in prior year sales affecting the opportunity to recover balances in prior years, and the utility’s costs of undertaking efficiency programs.
t = The current rate year under the price cap, where the value of ‘‘t’’ may range from *one* to N, with N representing the year after which continuation of the price cap is no longer required to allow recovery of potentially stranded costs given actual historic and forward market prices for the utility’s generation.

A more complex rate pattern would require defining some terms as indices, but would not change the basic structure of the price constraint.

CONCLUSION

The modified price cap approach provides a comparatively straightforward option for removing disincentives to market transformation, while retaining the incentives for cost and price minimization and pricing flexibility of a price cap. It avoids the need to rely on program evaluations in ratemaking to link market transformation effects to utility programs. And, it largely removes the primary source of uncertainty—forecasts of market prices—from the quantification of potentially stranded costs. If utility-supported market transformation programs are to survive a transition involving widespread use of PBR, it will be essential that policymakers adopt approaches that have characteristics comparable to the modified price cap approach. Such PBR approaches offer a useful bridge to a fully competitive power market that will require parties to develop new competitive institutions to promote energy efficiency.

REFERENCES

Baumol, W.J. 1989. ‘‘Productivity Incentive Clauses and Rate Adjustment for Inflation.’’ *Public Utilities Fortnightly* July 22.

Centolella, P.A. 1994. ''Converting Stranded Benefits into Opportunities: A Menu of Policy Options for Competitive Generation Markets.'' *In Proceedings of the National Association of Regulatory Utility Commissioners Annual Convention*. Washington, D.C.: National Association of Regulatory Utility Commissioners.

Centolella, P.A. 1995a. *The Quantification and Recovery of Potentially Stranded Costs*. Austin, Maine: The Regulatory Assistance Project.

Centolella, P.A. 1995b. ''Competitive Market Transformation: A Proposal for the Future of Energy Efficiency.'' *In Proceedings of the NARUC—EPA National Workshop on Market Transformation.* Tampa, Fla.: National Association of Regulatory Utility Commissioners—Environmental Protection Agency.

Comnes, G.A., S. Stoft, N. Greene, and L.J. Hill. 1995. *Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues.* LBL-37577, UC-1320. Berkeley, Calif.: Lawrence Berkeley Laboratory.

Crew, M.A., and P.R. Kleindorfer. 1995. ''Price Caps and Revenue Caps: Incentives and Disincentives for Efficiency.'' *In Proceedings of the Eighth Annual Advanced Seminar on Public Utility Regulation (Western Conference)*. San Diego, Calif.

Crew, M.A., and M.R. Frierman. ''Information Economics and New Forms of Regulation.'' *Competition and Regulation of Utilities.* M.A. Crew, Editor. Boston, Mass.: Kluwer Academic Press.

Hirst, E. 1993. *Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues.* ORNL/CON-372. Oak Ridge, Tenn.: Oak Ridge National Laboratory.

Joskow, P.L., and N.L. Rose. 1989. ''The Effects of Economic Regulation.'' *Handbook of Industrial Organization, Volume II.* R. Schmalensee and R.D. Willig, Editors. Amsterdam, Netherlands: North-Holland Press.

Joskow, P.L., and R. Schmalensee. 1986. ''Incentive Regulation for Electric Utilities.'' *Yale Journal of Regulation* 4(1).

Levine, M., E. Hirst, J. Koamey, J. McMahon, and A. Sanstad. March 1994. *Energy Efficiency, Market Failures, and Government Policy*, LBL-35376, ORNL/CON-383. Berkeley, Calif.: Lawrence Berkeley Laboratory.

Schmalensee, R. 1989. ''Good Regulatory Regimes.'' *RAND Journal of Economics.* 20(3) Autumn.

U.S. Energy Information Administration. 1996. *Utility Demand-Side Management: Trends and Analysis.* Publication Forthcoming. Washington, D.C.: U.S. Energy Information Administration.