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WHITE PAPER ON INCENTIVE REGULATION: ASSESSING UNION ELECTRIC'S EXPERIMENTAL ALTERNATIVE REGULATION PLAN

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EXECUTIVE SUMMARY

Incentive regulation (also called performance-based regulation or "PBR") has made substantial inroads in the electric utility industry. We have identified 28 electric utility companies in 16 states that presently operate under some form of comprehensive (*i.e.*, broad-based) incentive regulation. The most common types of incentive regulation are price cap plans, rate freezes or rate case moratoria, and earnings sharing plans. Union Electric's Experimental Alternative Regulation Plan ("EARP") is a common form of incentive regulation that combines a rate freeze with earnings sharing.

Incentive regulation offers many broadly-recognized advantages over traditional cost-of-service regulation ("COS regulation" or "COSR"). First, well-designed PBR plans provide utilities with stronger incentives to reduce or control costs and improve other aspects of performance. Second, incentive regulation can provide improved rate predictability for customers. Third, incentive regulation can secure immediate customer participation in the company's improved performance, particularly if combined with earnings sharing. Fourth, PBR has the potential to save administrative and transaction costs by avoiding regulatory micro-management of a company's operations and by reducing the number of litigated rate cases. And, finally, by providing an electric utility with incentives similar to those faced by firms in competitive markets, performance-based regulation can serve both as a tool to regulate traditional utility operations and as a transitional mechanism to restructured, more competitive electricity markets.

The advantages of incentive regulation for electric utilities have been sufficiently apparent to many regulatory commissions that they have endorsed incentive regulation wholeheartedly. Evidence from the electric utility and telecommunications industry suggests that incentive regulation has provided important benefits to customers and regulated companies alike.

Incentive regulation must be designed carefully if it is to achieve its full potential. Key attributes of a well-designed PBR plan are:

1. *Transparency and simplicity.* The features and operation of the plan must be transparent and unambiguous in their interpretation. Transparency and simplicity increase acceptance by various interest groups, increase the "staying power" of the PBR plan, reduce the likelihood of disputes, and reduce the burden of administering the plan.

2. *Proper motivation and scope.* To best motivate the regulated firm to improve its performance, incentive regulation plans should link financial rewards to broad-based measures of a company's overall performance. There is, however, little to be gained by holding the regulated firm fully responsible for costs that are entirely beyond its control.

3. *Balance of risks and rewards.* Incentive regulation should provide the prospect of enhanced benefits for shareholders and customers by carefully balancing risks and rewards. Earnings sharing can ensure that rewards and penalties remain within politically and operationally acceptable limits.

4. *Term and Commitment.* A relatively long commitment period and clearly defined terms and conditions are essential if a PBR plan is to provide meaningful incentives to improve performance, reduce administrative costs, and avoid regulatory gaming by affected groups. PBR plans can only provide meaningful incentives to enhance performance if the regulated firm is confident that promised rewards will, in fact, be delivered. Attempts to appropriate such rewards will undermine the viability of future incentive plans.

Union Electric's EARP is a simple but effective form of incentive regulation. The EARP's design parameters are generally comparable to those in many other plans, but are notably conservative in some respects. In particular: (1) the commitment period of three years is relatively short; (2) the EARP does not allow for a ready pass through of uncontrollable costs; and (3) the earnings sharing provisions greatly limit possible rewards while providing no down-side protection. UE's ability to initiate a new rate case if adverse conditions arise is an imperfect substitute for pass-through provisions, and leaves the Company with a significant risk of not recovering costs related to events that are beyond its control.

A preliminary evaluation shows that the EARP settlements have significantly benefitted Union Electric's customers through permanent rate reductions, up-front customer credits, and ongoing sharing credits. These EARP-related payments and rate reductions have combined to deliver more than $400 million in benefits to customers (not including the benefits that customers received from Ameren's merger-related concessions), relative to the retail rates that were in effect prior to the EARP. Furthermore, these benefits have been delivered to customers expeditiously. Under traditional cost-of-service regulation, customers would not have been able to enjoy any realized benefits until after the conclusion of a rate case.

It is difficult to calculate precisely the benefits that the EARP has delivered relative to traditional cost-of-service regulation. The difficulty arises because it is impossible to identify precisely the rates that customers would have paid in 1995-2001 had the EARP not been implemented. There is little doubt, though, that Union Electric's current cost of service may be substantially lower than it would have been had the Company been operating under cost-of-service regulation in recent years. This is because the EARP has provided Union Electric with stronger incentives to improve performance. In fact, under the EARP, Union Electric has introduced broad management and employee incentive programs. These programs help to ensure that the beneficial incentives provided by the EARP filter throughout the entire organization, to the ultimate benefit of customers and shareholders alike.

Union Electric's customers paid 4.8 percent less for electric power in 1999 than they paid in 1994, the year before the EARP was first implemented. (During the same time period, average consumer prices increased 12.4 percent.) Furthermore, all of UE's customer classes enjoyed a greater reduction in electricity rates than customers of other utilities in the region. In particular, since 1994, UE's retail rates have decreased by 2.5 and 5.2 percent more than the average rates of utilities in the East-North-Central and West-North-Central regions of the United States, respectively. This comparison suggests that annual expenditures by UE's customers may have already declined between $50 million to $100 million *more* than they would have had UE achieved only the average rate reduction of other Midwest utilities.

These facts suggest that the EARP may well have served to deliver more benefits to customers than they would have received under traditional cost-of-service regulation. The continuation of the EARP, therefore, merits serious consideration. A step backward to cost-of-service ratemaking—or a resetting of UE's retail rates based on overly aggressive cost-of-service standards—would undermine the superior incentives that have motivated the Company to improve performance and deliver substantial benefits to customers since 1995.

As a possible new EARP settlement is negotiated, some potential enhancements to the current incentive regulation plan warrant careful consideration. In particular, the commitment period might be extended to four or five years. The sharing bands might be widened to allow more up-side rewards. Various pass-through provisions for uncontrollable costs might be added to increase the EARP's "staying power." Issues that have caused disputes in the past might also be addressed explicitly for the future to reduce the likelihood or magnitude of disputes. In addition, a target rate of return above the return that would be allowed under cost-of-service regulation is warranted.

In summary, Union Electric and its customers alike have benefitted from the EARP over the past five years. Specific recognition that such a win-win situation can be achieved through incentive regulation is key to the successful negotiation and implementation of future alternative rate plans.

I. INTRODUCTION AND OVERVIEW

Since 1995, the Union Electric Company ("Union Electric," "UE" or "Company") has provided retail electric service pursuant to an Experimental Alternative Regulation Plan ("EARP").[1] The Company is currently providing retail service under a second, new EARP approved by the Missouri Public Service Commission ("MPSC" or "Commission") in 1997.[2] Both EARPs resulted from settlements endorsed by a wide array of Missouri stakeholders. Each of these plans provided up-front customer credits, reduced UE's rates, immediately froze rates at their reduced levels for at least three years,[3] and required UE to share with its customers any earnings in excess of a defined threshold return on equity (threshold "ROE"). Presently, parties to the settlement are assessing whether Union Electric's EARP "should be continued as is, continued with changes (including new rates, if recommended) or discontinued."[4] As explained below, Union Electric's EARP is a common form of incentive regulation or performance-based regulation ("PBR"), even though it is not specifically identified as such.[5]

Incentive regulation has become increasingly popular in many network industries throughout the world. PBR has a long history in the regulation of U.S. telecommunications carriers, and this history offers useful insights to the electric utility industry. More than 40 states now employ incentive regulation to regulate the intrastate operations of local exchange carriers.[6] A transition toward incentive regulation also is underway in the U.S. electric industry. As discussed in Section III of this Paper, we have identified 28 electric utilities in 16 states that

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1 Public Service Commission of the State of Missouri (1995a) ("*First EARP Order*"). See also Public Service Commission of the State of Missouri (1995b) *Stipulation and Agreement* ("*First EARP Agreement*").

2 Public Service Commission of the State of Missouri (1997) ("*Second EARP Order*"). See Section 7 of the Public Service Commission of the State of Missouri (1996) *Stipulation and Agreement.* ("*Second EARP Agreement*").

3 As part of the first EARP settlement, however, UE agreed to conduct a "class cost-of-service study" and rate design review. Thus, while the EARP imposed a rate case moratorium, it allowed for the adjustment of rate structure.

4 *Second EARP Agreement*, p. 16.

5 The terms "incentive regulation" and "PBR" will be used interchangeably throughout this Paper.

6 For example, see Sappington (2001).

currently operate under some form of broad-based incentive regulation.[7] Most of these incentive plans contain features similar to those present in Union Electric's EARP.

The strong interest in PBR is driven by the perceived shortcomings of traditional rate-of-return or cost-of-service regulation ("COS regulation" or "COSR"), by the increasing competition in restructured wholesale and retail power markets, and by the benefits that incentive regulation has delivered to date. Among many independent scholars, the consensus is that incentive regulation has the potential to deliver outcomes superior to those achieved under cost-of-service regulation.[8] As we demonstrate in Section IV, there is also growing empirical evidence regarding the benefits that incentive regulation has delivered to consumers and regulated companies alike.

The remainder of this Paper is organized as follows. Section II defines incentive regulation and explains the key differences between incentive regulation and cost-of-service regulation. Section II also describes the most common forms of incentive regulation and discusses the qualitative advantages of incentive regulation relative to cost-of-service regulation.

Section III summarizes the history and current status of incentive regulation. It first documents the evolution of incentive regulation in the U.S. telecommunications industry—an industry that shares many traits with the electric utility industry, including a long history of cost-of-service regulation. Section III then reviews the status of PBR in the electric utility industry today and describes some of the incentive plans used in states with significant PBR experience.

Section IV documents the favorable views of incentive regulation held by several regulatory commissions that have significant PBR experience. The section also summarizes the empirical evidence regarding the benefits that PBR has delivered in the telecommunications industry.

Section V identifies and discusses the key attributes of well-designed incentive regulation plans.

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7 See Table 2 "Status of PBR in U.S. State Regulation of Electric Utilities" in Section III.B. below.

8 For example, see *Rand Journal of Economics* (1989); Brown, Einhorn, and Vogelsang (1989); Stoft, Green, and Hill (1995); and Sappington and Weisman (1996a).

Section VI presents an assessment of Union Electric's EARP, including a preliminary evaluation of the consumer benefits that the EARP has delivered. Section VI also provides recommendations for enhancing the EARP.

Section VII summarizes our primary conclusions.

II. TYPES AND ADVANTAGES OF INCENTIVE REGULATION

A. DEFINING INCENTIVE REGULATION

Incentive regulation can be defined as the implementation of rules, including explicit financial incentives, that encourage a regulated firm to achieve desired performance goals, while affording the firm significant discretion in how the goals are achieved. This discretion enables the firm to employ its superior knowledge of its operating environment to achieve the stated goals. A greater reliance on explicit financial incentives and a more pronounced delegation of discretion to the firm is what distinguishes incentive regulation from cost-of-service regulation.[9]

A key distinction between incentive regulation and cost-of-service regulation is the extent to which a company's rates are linked to its costs. (By "costs" we mean a regulated company's cost of service as measured by its revenue requirements or its revenue requirement per kilo-Watt hour of sales.) Under COSR, this linkage between rates and costs is strong and explicit. A company's rates are typically set on a "cost-plus" basis to recover the company's cost of service, *i.e.*, to yield expected revenue exactly equal to what is needed to recover the costs that are incurred prudently. The firm's costs include the return on

[9] See Sappington and Weisman (1996a). However, because the goals of consumers and the firm can be disparate in certain regards, the discretion afforded to the firm cannot be unlimited. Thus, incentive regulation also requires a delicate balance of discretion and limitations.

investment that investors require in order to invest in the firm.[10] Thus, cost-of-service regulation effectively links rates directly to realized costs.

Under traditional COS regulation, regulatory lag—the time between rate cases—can also provide the regulated firm with some incentive to operate efficiently and improve its performance. The incentive arises because the regulated firm can benefit temporarily from the increased earnings that result from improved performance. However, the incentive is often limited and uncertain because the time between rate cases can be short, and any benefits that a company captures through improved performance are truncated in the next rate case. Such benefits will be particularly short-lived if rate reviews occur automatically as earnings increase. By design, COS regulation presents the regulated firm with a fair opportunity to earn its revenue requirement, no more and no less. Consequently, COS regulation limits a company's incentives to discover innovative ways to control costs, because such innovations promise little or no reward.

In contrast, incentive regulation partly severs the direct link between realized costs and authorized rates. By doing so, incentive regulation can create strong incentives for a company to reduce or control its costs and improve other measures of financial performance. Incentive regulation also can be designed to encourage other goals, such as maintaining or improving customer service and encouraging certain investments (*e.g.*, network modernization or energy efficiency investments). Incentive regulation provides these incentives by explicitly allowing a company to earn more than its target return[11] if the company delivers superior performance. However, incentive regulation also entails the risk of earning less than the target return if a company delivers sub-par performance.[12] Thus, just

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[10] Throughout this Paper, references to costs and cost recovery assume costs to be incurred prudently. A company's total cost of providing electric service, including the return on its net investment, is referred to as its "revenue requirement." "Required rate of return" refers to the return that investors require in order to invest their money in the firm. Under cost-of-service regulation, a company's authorized rate of return generally is set equal to the required rate of return.

[11] The "target return" can be viewed as the return the regulated firm might reasonably be expected to achieve under the incentive regulation plan. The target return should be at least equal to investors' required return, taking into account any special risks that the company may face under incentive regulation.

[12] While companies can, and often do, earn more or less than their required return under COSR, it is typically not by design. Rather, it is primarily due to regulatory lag and the fact that costs and sales cannot be predicted with complete accuracy.

as it embodies a delicate balance of discretion and limitations, incentive regulation also provides a careful balance of risks and potential rewards.

B. TYPES OF INCENTIVE REGULATION

There are many different types of incentive regulation. Price caps, rate freezes or rate case moratoria, and earnings sharing plans are among the most common forms of incentive regulation in use today.[13]

Price Cap Regulation:

Price cap regulation permits a company's rates to be adjusted according to a pre-determined formula for a specified commitment period. The commitment period is often five years, but ranges from three to seven years. Price cap plans are often referred to as "RPI-X" plans because the price cap formula allows average rates to rise annually at the rate of retail price inflation ("RPI") less a productivity offset ("X").[14] In principle, the productivity offset to general inflation rates reflects the amount by which annual productivity growth in the regulated industry as a whole is expected to differ from that in the broad economy.[15] During the commitment period, the regulated company has strong incentives to increase earnings by reducing costs, since regulated prices are not linked directly to the company's realized costs.

Price cap plans usually contain "pass-through factors"[16] as well as "rate flexibility" provisions. Pass-through factors allow for additional rate increases or decreases if certain

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13 In the 1980s and early-to-mid 1990s targeted incentive programs such as power plant performance incentives and/or demand-side management (DSM) incentives were also common.

14 The term "RPI-X" was coined originally in the U.K., where price caps have become the predominant form of regulation. RPI denotes the Retail Price Index, the U.K. equivalent of the U.S. Consumer Price Index.

15 Bernstein and Sappington (1999). The productivity offset can be positive, zero, or negative. If productivity improvements in the regulated industry are expected to match those in the economy as a whole, for example, the productivity offset will be zero and the price cap will allow a company's average rates to track economy-wide price changes. Of course, X factors should not be set to usurp the future earnings that the company has rightfully earned in the past. If X factors are set in this manner, the beneficial incentive effects of price cap regulation will be seriously undermined.

16 These pass-through factors are often referred to as "Z-Factors" and explicitly incorporated in an expanded "RPI-X+Z" price cap formula.

uncontrollable costs (*e.g.*, costs associated with natural disasters or changes in taxes and environmental regulations) occur during the commitment period. Under rate flexibility provisions, rates for individual services can be adjusted or new services can be introduced without a rate hearing, subject to predetermined limitations, as long as the company's average rate does not exceed the specified price cap. Rate flexibility provisions can be particularly important when regulated companies face rapidly changing industry fundamentals and significant competition in some service segments.

Rate Freezes and Rate Case Moratoria:

Under a rate freeze, a company's rates are held constant during the commitment period. A rate case moratorium is similar to a rate freeze in that it represents a commitment not to initiate a rate case designed to increase or reduce rates. A rate case moratorium, however, may admit some adjustment of the *rate structure*. In other words, some individual rate elements may be changed, even though the average level of rates remains unchanged within or across customer classes.

Rate freezes and rate case moratoria are relatively simple forms of PBR. They can provide strong incentives while ensuring rate stability.[17] Knowing that, during the commitment period, it cannot seek a rate increase nor will it face rate reductions to match cost reductions, the company that operates under a rate freeze or a rate case moratorium will have strong incentives to reduce or control its operating costs. These incentives generally increase with the duration of the commitment period. However, without inflation adjustments or a pass through of uncontrollable costs, lengthy commitment periods can impose significant risk on the regulated firm.

Earnings Sharing Plans:

Earnings sharing plans implement explicit sharing of realized earnings between the regulated firm and its customers. Earnings sharing plans, like Union Electric's EARP, allow

[17] Rate freezes and rate case moratoria resemble price cap (*i.e.*, RPI-X) plans in which the productivity offset (X) equals the inflation rate (RPI). This analogy to price caps is particularly relevant since rate case moratoria, like price caps, have been combined with pass-through factors and rate flexibility provisions. The simplicity of rate freezes and rate case moratoria can provide an important advantage over price cap plans.

customers to share in a company's achieved earnings in excess of pre-determined threshold returns on equity (ROE), either through sharing credits or lower rates in subsequent years. Many sharing plans also require customers to bear a portion of any shortfall of earnings below certain ROE thresholds.

The rate at which incremental earnings are shared under an earnings sharing plan can vary with the level of earnings. To illustrate, a simple earnings sharing plan might specify a deadband range of earnings around (*i.e.*, above and often below) the target return on equity. Incremental earnings within this deadband are not shared with customers. Outside of the deadband, however, customers might be afforded a sizeable fraction (*e.g.*, one half) of incremental earnings. Sharing plans might also include an upper (and perhaps a lower) bound beyond which all incremental (or decremental) earnings are passed through to customers.

Earnings sharing plans typically work in combination with rate freezes, rate case moratoria, or price caps. The purpose of earnings sharing is to keep a company's earnings at politically and operationally acceptable levels during the plan's commitment period.[18] Sharing also makes customers "stakeholders" in the performance of the company. As the company's performance improves over time, benefits accrue to customers and shareholders alike.

Earnings sharing rules require careful balancing of the benefits delivered to customers and the incentives provided to the regulated firm. As customers are awarded a larger share of the firm's realized cost reductions, the firm's incentives to undertake the additional effort and sacrifice required to improve performance are blunted. Deadbands (in which no sharing occurs) and sharing bands that are wide enough to provide substantial up-side potential can provide a desirable balance.

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[18] Earnings sharing reduces the likelihood that the incentive plan will result in extreme outcomes during the commitment period. Earnings vastly in excess of the target return would likely draw politically unacceptable criticism from consumer groups, while earnings well below the target return could impair the company's financial viability and thus be operationally unacceptable. The political implications of extreme outcomes are broader. Under-investment in generation, transmission, or distribution systems due to low allowed returns can reduce service reliability. For example, outcomes that impair a utility's viability will also impair the investment of the utility's local stock holders. (Approximately one-third of Ameren's shareholders are residents of Missouri.)

Targeted Incentives:

This Paper focuses on "broad-based" or "comprehensive" PBR plans that address the overall operation of a company. Today, broad-based incentive plans, such as Union Electric's EARP, are the predominant form of incentive regulation. Prior to 1990, targeted incentives designed to improve a particular aspect of a company's performance were common in the U.S. electric industry. In many cases, targeted incentives were established to improve the performance of one or more of a company's generating units or to control fuel and purchased power costs.[19] In the early-to-mid 1990s, demand-side management (DSM) programs included targeted incentives (and broad-based revenue caps) to curtail the growth of demand for electricity.[20]

Targeted incentives have generally given way to broad-based PBR plans in part because targeted incentives can encourage the regulated firm to focus too much on the identified target and too little on other important performance dimensions. However, targeted incentives can still be a useful supplement to broad-based incentives. For example, targeted incentives to improve service quality and customer satisfaction often are included in price cap plans—particularly when a company's perceived service quality is low, or when it is feared that quality may decline as costs are reduced.

C. ADVANTAGES OF INCENTIVE REGULATION

Incentive regulation offers many advantages over traditional cost-of-service regulation. The advantages of incentive regulation include superior performance incentives, improved rate predictability, more timely consumer benefits, lower administrative/regulatory costs, and greater compatibility with a rapidly changing, increasingly competitive industry.

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[19] For example, see Hill (1995), p. 13.

[20] Revenue caps limit a company's allowed revenues and thereby limit the company's incentive to expand sales. Revenue adjustment mechanisms help to restore revenues that would otherwise decline as successful DSM programs reduce customer demand for electricity.

Superior Performance Incentives:

Incentive regulation can provides strong incentives to increase performance because it allows a company to derive a significant financial benefit from doing so. This benefit is precisely the incentive that motivates firms in competitive markets to control costs and deliver superior service to their customers. In contrast, under COSR—where cost reductions call forth matching revenue reductions—the company has little or no financial incentive to deliver the significant effort required to identify and implement measures to reduce or control costs.[21] Incentive regulation also can limit incentives to overinvest in plant and equipment (which can increase costs under COSR),[22] thereby reducing both the risk of unnecessary investment and the need for extensive regulatory monitoring of investment activities.

The beneficial role of incentive regulation in motivating improved performance has been documented in conceptual and applied research studies. For example, in 1995, the Lawrence Berkeley National Laboratory ("LBNL") assessed the incentives provided by eleven types of incentive regulation plans then in effect or under consideration for the regulation of electric utilities.[23] LBNL constructed a metric—called the LBNL Incentive Power Index—which measured the extent to which a company's profits were at risk under its PBR plan. The LBNL study concluded that well-designed PBR plans clearly provide better incentives to control costs than traditional cost-of-service regulation.[24] The study further concluded that rate freezes or rate case moratoria are a particularly simple way to increase performance incentives.[25]

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[21] Sappington and Weisman (1996b).

[22] This effect of cost-of-service regulation is often referred to as the Averch-Johnson effect. For a discussion of this effect, see, for example, Bonbright, Danielsen, and Kamerschen (1988), pp. 356-359.

[23] Comnes, *et al.* (1995).

[24] While "most plans represent an improvement over the utility's status quo" (LBNL Study, p. 54), the study also found "some PBR [plans] with incentive powers that differ little from COS [regulation]"(p. xxv). Thus, incentive plans must be designed carefully if they are to achieve their full potential.

[25] *Ibid.*, p. xvi.

Improved Rate Predictability:

PBR typically provides significant rate predictability for customers. It does so because rates are based on a pre-determined methodology for a clearly specified commitment period. A rate freeze, like the one included in UE's EARP, provides especially pronounced price predictability. Rate case moratoria also provide substantial rate predictability because they preclude requests for general rate increases during the commitment period.[26] Price cap plans can also provide considerable rate predictability because they specify clearly the formula and the inflation and productivity measures that will be used to adjust rates on an annual (or other periodic) basis.[27] COSR can introduce greater rate uncertainty because it does not specify in advance when rates will change or by how much they will change.

Timely Customer Benefits:

Incentive regulation with earnings sharing provisions, such as Union Electric's EARP, enable customers to benefit quickly from realized cost reductions. In contrast, under COSR, any realized cost reductions are typically passed on to customers only after a lengthy rate case is concluded. Even price cap regulation that entails no earnings sharing delivers benefits to customers continually by limiting the rate at which prices are allowed to increase. In addition to delivering the benefits of improved performance to customers more quickly, well-designed PBR plans also increase the likelihood that larger benefits will be available to share. Thus, incentive regulation can deliver greater benefits to customers than COS regulation would deliver.

Lower Administrative and Regulatory Costs:

PBR can also reduce administrative and regulatory costs. Litigated cost-of-service rate cases impose substantial costs on the company, the regulator, and the intervening parties. These rate cases also tend to be slow, cumbersome processes. Even before rates set through formal

[26] Under Union Electric's first two EARPs, rates have not increased for six years. In fact, rates have declined because of initial rate reductions and sharing credits.

[27] As noted, such formulas typically link rate increases to the general inflation rate and to a specified productivity offset (the X factor).

rate cases take effect, they can be out of date in terms of underlying costs and competitive conditions in the industry.

Regulators benefit from incentive regulation to the extent that it relieves them of the arduous task of micro-managing the activities of the regulated firm. This benefit is particularly significant in a rapidly changing, increasingly complex industry. Reduced regulatory micro-management enable companies to respond more rapidly to such technological and competitive challenges.

PBR is also compatible with alternative dispute resolution ("ADR") procedures. Much of the interest in ADR among state regulators is driven by a desire to reduce the time, cost, and contentiousness associated with litigated rate cases. PBR is consistent with the principles and goals of ADR because it can provide an informal, collaborative process for setting and reviewing rates.

Compatibility with Competition:

A well-designed incentive regulation plan can facilitate the transition to more competitive power markets by replicating the stimuli that competition delivers. In particular, PBR can provide an electric utility with incentives to improve performance—whether in generation, transmission, or distribution—that are similar to the incentives faced by firms in competitive markets. As a result, performance-based regulation can serve both as a transitional mechanism to restructured, more competitive electricity markets and as a substitute for actual competition.

While delivering strong incentives to improve performance, incentive regulation can also provide some of the pricing flexibility that firms typically enjoy in a competitive market. Price caps, for example, may set a *ceiling* on a company's average rates (or average rates per customer class)—leaving the company some discretion to adjust rate structures, to adjust rates across customer classes, or simply to reduce rates to attract or retain customers.[28] This

[28] In the electric utility industry, a "floor" or minimum rate is often specified. The minimum rate is usually set to ensure that all customers pay at least the marginal cost of the service they consume. Some price cap plans with rate flexibility across customer classes (such as PBR plans in Maine) also limit the extent to which revenues can be shifted across customer classes.

rate flexibility allows a company to move rates closer to costs and to respond to competitors' prices in a timely fashion. Unlike the standardized "discount" or "economic development" rates that many utilities implemented in the 1980s, pricing discretion under PBR plans affords a utility the flexibility it requires to meet competitive challenges as they arise.

III. DEVELOPMENT AND STATUS OF INCENTIVE REGULATION

In the U.S. energy industry, incentive regulation began in the early 1980s with power plant performance incentives that were narrowly focused on improving plant availability or on reducing power plant operating costs. Incentives for energy efficiency (*i.e.*, demand-side management or "DSM") followed in the early 1990s. DSM incentives included a variety of unique mechanisms, such as revenue caps (in which companies could increase rates if they decreased sales), rate-of return incentives (which increased the allowed returns based on the achievement of energy conservation targets), adjustments to lost revenues (which compensated utilities for revenue reductions caused by energy conservation initiatives), and DSM shared savings mechanisms (which allowed utilities to share some of the benefits customers received through utilities' conservation activities).[29] Broad-based incentive regulation in the form of rate freezes, earnings sharing, and price caps have become more common in the U.S. energy industry in recent years.

Price caps have been widely applied in the U.K. and other Commonwealth countries, starting in the early-to-mid 1980s with the privatization and restructuring of British network industries.[30] Price caps are known in the U.K. as "RPI-X" regulation, where "RPI" stands for Retail Price Index—the U.K. equivalent of the Consumer Price Index ("CPI"). In the U.S., price caps were first introduced in the telecommunications industry in the 1980s, but gained widespread popularity only in the early 1990s. In the U.S. energy industry, price caps were first proposed in the early 1990s. Since electric utility industry restructuring was initiated in the mid-1990s, price caps and other forms of broad-based incentive regulation have become more popular as a means to regulate the transmission and distribution functions

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29 Comnes *et al.* (1995).

30 One of the first price cap plans was adopted in 1980 for Michigan Bell Telephone Company by the Michigan Public Service Commission. It was discontinued in 1983 in anticipation of the AT&T divestiture. (Brown, Einhorn and Vogelsang, 1989).

of restructured utility operations. However, even in jurisdictions where restructuring is limited, incentive regulation can serve as a vehicle to provide regulated firms with incentives that are similar to those in competitive markets. In states with less aggressive restructuring postures, implementation of incentive regulation can provide important benefits while problems associated with electric utility restructuring (like those in California)[31] are being sorted out.

The remainder of this Section first discusses the evolution of broad-based incentive regulation in the U.S. telecommunications industry and then takes inventory of broad-based incentive regulation plans in the U.S. energy industry. The discussion of incentive regulation in the telecommunications industry is useful because of the relatively long history of experience with incentive regulation in that industry. Because the telecommunications industry differs from the electric utility industry in some respects, caution must be exercised when drawing parallels between the industries. But history is generally a learned teacher, and the telecommunications and electric utility industries share important features. Both are capital intensive network industries with significant scale economies; both offer universal service as a public policy objective and are expected to continue to provide reliable, affordable service; and both have long histories of operating under cost-of-service regulation.

A. EVOLUTION OF PBR IN THE U.S. TELECOMMUNICATIONS INDUSTRY

Table 1 records the PBR plans that have been employed by state regulators of the U.S. telecommunications industry since 1985. The table focuses on the most popular forms of regulating the primary incumbent supplier of telecommunications services, the regional Bell Operating Company ("RBOC"). Three distinct patterns are evident from Table 1. First, rate case moratoria were the most popular form of incentive regulation in the mid and late 1980s, when alternatives to COS regulation first emerged. Second, earnings sharing regulation

[31] Note that the price spikes and supply problems experienced by California in the restructuring of its electric utility industry are unrelated to its implementation of incentive regulation. Rather, the problems in California appear to relate primarily to supply shortages (partly triggered by rapid economic growth, stringent environmental constraints, siting difficulties, and restructuring-related investment uncertainties) in combination with poorly-designed market rules and restructuring conditions (including the requirements that utilities divest their fossil-fired generation assets and buy their *entire* power requirements in the spot market). Note also, however, that the California experience with retail rate freezes also points to the importance of "regulatory out clauses" and pass-through provisions for significant uncontrollable costs.

(often in combination with rate case moratoria and early price cap plans) became particularly popular in the early 1990s, as the number of pure rate case moratoria declined. Third, few states employed pure price cap regulation (*i.e.*, price caps with no earnings sharing) until the mid 1990s. However, by 1996, pure price cap regulation had become the predominant form of regulation, and it remains the predominant form of regulation today.

The patterns exhibited in Table 1 reflect a natural progression from less aggressive to more aggressive departures from COSR. Rate case moratoria essentially codified the longer time spans between rate reviews that were already occurring in the 1980s, as inflation subsided and production costs declined. Earnings sharing in combination with rate freezes and, increasingly, price caps constituted a natural progression beyond simple rate case moratoria. Earnings sharing assured that outcomes stayed within operationally and politically acceptable bounds. Increasing experience with rate indexing under price cap plans and the desire to provide even stronger efficiency incentives encouraged regulators to implement pure price cap regulation on a broad scale by the mid 1990s. Federal regulation of the local exchange carriers similarly moved first from earnings sharing regulation to a choice between earnings sharing and price cap regulation, and then on to pure price cap regulation.[32]

Emerging competition in the telecommunications industry likely enhanced the appeal of price cap regulation. As competitors imposed increasing discipline on incumbent providers of telecommunications services, direct regulatory control of earnings may have become less essential. Price cap regulation also provided incumbent providers with the expanded pricing flexibility needed to meet the competitive challenges that they faced in certain service segments. Subject to the cap on average prices, this flexibility generally allowed the firms to offer discounts and, within limits, to adjust their rate structure.

[32] The Federal Communications Commission (FCC) provided the RBOCs with a choice between two price caps/earnings sharing plans during 1991-94 in order to regulate interstate access charges. In 1995 and 1996, the FCC afforded the RBOCs a choice among two different price caps/sharing plans and a pure price-cap regulation plan. In 1997, the FCC imposed the same pure price-cap regulation on all RBOCs (Sappington 2001).

Table 1
Evolution of PBR in U.S. Local Telecom[33]

Year	Cost-of-Service Regulation	Pure Rate Freezes or Rate Case Moratoria	Earnings Sharing Regulation	Pure Price Cap Regulation (no sharing)	Other Forms of Regulation
1985	50	0	0	0	0
1986	45	5	0	0	0
1987	36	10	3	0	1
1988	35	10	4	0	1
1989	29	10	8	0	3
1990	23	9	14	1	3
1991	19	8	19	1	3
1992	18	6	20	3	3
1993	17	5	22	3	3
1994	20	2	19	6	3
1995	18	3	17	9	3
1996	14	4	5	24	3
1997	12	4	4	28	2
1998	13	3	2	30	2
1999	11	1	1	35	2
2000	7	1	1	39	2

33 Sappington (2001). The entries in Table 1 reflect the number of states that employed the specified form of regulation.

B. PBR in the U.S. Electric Utility Industry Today

Incentive regulation has already made substantial inroads in the electric utility industry. We have identified 28 electric utility companies in 16 states that presently operate under some form of comprehensive (*i.e.*, broad-based) incentive regulation. **Table 2** lists these incentive plans and indicates whether these plans are based on rate case moratoria or rate freezes, price caps, and/or earnings sharing. Most of the plans entail rate freezes (including rate case moratoria) or price caps. The majority of plans also contain earnings sharing provisions or simple deadbands (*i.e.*, ranges in which the regulated firm is permitted to keep all of the earnings it generates in the market place).

Table 2 shows that in some states with significant incentive regulation experience (such as California, Maine, and New York), PBR programs generally have evolved from revenue caps in the early 1990s to price caps. Of the identified 28 electric utilities, 13 operate under some form of rate freeze (or rate case moratorium), while 14 utilities operate under price caps. Of these 28 PBR plans, 21 contain earnings sharing provisions or simple deadbands. Three of the identified PBR plans have transitioned (or will be transitioning) from rate freezes to price caps. In a number of states with a restructured utility industry, price freezes on retail rates are also combined with PBR plans for unbundled distribution services.

Table 2 also shows that many states implemented PBR plans in the electric utility industry only recently. However, several states have accumulated significant experience with broad-based incentive plans for years. In addition to Union Electric's EARP, examples of such experience are the incentive plans adopted for Alabama Power Company ("Alabama Power"), San Diego Gas & Electric Company ("SDG&E"), and Central Maine Power Company ("CMP"). The incentive plans under which these three companies operate are discussed briefly below. The regulatory commissions' assessments of the experiences with PBR in Alabama, California, and Maine are discussed in Section IV of this Paper.

Table 2
Status of Broad-Based PBR in U.S. State Regulation of Electric Utilities

State	Company	Period	Type of Plan
AL	Alabama Power Co.	1982 to present	Rate case moratorium with rate-of-return deadband.
CA	San Diego Gas & Electric Co.	1994-1998	Revenue cap for base rates, natural gas, and power procurement incentives with earnings sharing.
		1999-2002	Price cap (on distribution services) with earnings sharing.
	Southern California Edison Co.	1997-1998	Price cap (on transmission and distribution services) with earnings sharing.
		1998-2001	Price cap (on distribution services) with earnings sharing.
CO	Public Service Co. of Colorado	1997-2001	Rate case moratorium (for base rates) with earnings sharing.
		2001-2006	Rate freeze (for base rates) with earnings sharing through 2006; reset base rates in 2002.
FL	Tampa Electric Co.	1995-1999	Rate freeze (for base rates) with earnings sharing.
IA	Mid-American Energy	1998-2000	Rate case moratorium with earnings sharing.
IL	CILCO	1998-2002	Price cap and earnings sharing with rate adjustments based on regional comparison of average retail rates.
	Ameren CIPS-UE	1998-2002	same
	ComEd	1998-2002	same
	MEC	1998-2002	same
	IP	1998-2002	same
LA	Entergy LA	1996-1997	Rate case moratorium with earnings sharing.
		1998-2000	Renewed previous plan for 3 years.
		2001	Extended plan for an additional year.
MA	MECo (EUA/Edison)	1998-2000	Rate freeze (for base rates) with earnings sharing.
		2000-2005	Rate freeze for distribution service.
		2005-2009	Price cap for distribution service.
	NSTAR	1998-2002	Rate freeze for distribution service.

State	Company	Period	Type of Plan
ME	Bangor Hydro Electric	1995-1998	Rate case moratorium with rate flexibility.
		1998-2000	Price cap with earnings sharing.
	Central Maine Power	1991-1993	Revenue-per-customer cap.
		1995-2000	Price cap with earnings sharing.
		2001-2007	Price cap for distribution service.
	Maine Public Service Company	1996-2000	Price cap with earnings sharing.
MO	AmerenUE	1995-1998	Rate freeze with earnings sharing.
		1998-2001	Rate freeze with earnings sharing.
MS	Mississippi Power	1995-present	Rate case moratorium with earnings sharing.
MT	Montana Power	1997-1998	Price cap with earnings sharing.
ND	Northern States Power	2001-2005	Price cap with earnings sharing.
	Otter Tail Power	2001-2005	Price cap with earnings sharing.
NY	Consolidated Edison	1995-1997	Revenue-per-customer cap with earnings sharing.
		1997-2000	Rate case moratorium with earnings sharing.
		2001-2005	Rate freeze (for transmission and distribution services) with earnings sharing.
	New York State Electric & Gas	1993-1995	Price cap (for base rates) with earnings sharing.
		1995-1998	Price cap with earnings sharing.
		1998 to present	Rate freeze with earnings cap.
	Niagara Mohawk	1991-1995	Revenue cap.
		1998-2002	Rate freeze for three years, followed by a price cap (for distribution and transmission services) for last two years.
	Rochester Gas and Electric	1993-1996	Revenue cap with earnings sharing.
		1996-1997	Rate case moratorium (for base rates) with earnings sharing.
		1998-2002	Rate case moratorium with earnings sharing.

State	Company	Period	Type of Plan
OR	PacifiCorp	1994-1995	Price cap.
		1998-2001	Revenue cap (for distribution service) with earnings sharing.
RI	Narragansett Electric Company	1997-1998	Price cap with earnings sharing.
	EUA/Blackstone Valley /Newport Electric	1997-1998	Price cap with earnings sharing.
	Narragansett Electric Company	2000-2004	Rate freeze (for distribution service) with earnings sharing.
SD	Black Hills Power & Light	1995-2000	Rate freeze.
		2000-2005	Rate freeze.
WA	Puget Sound Energy	1997-2001	Price cap.

Alabama Power Company:

Alabama Power Company has been operating under a Rate Stabilization and Equalization ("RSE") plan since 1982.[34] Under the RSE (as revised in 1990), Alabama Power is allowed to earn a return on equity in a range between 13.0 and 14.5 percent.[35] If the company's actual ROE for a 12-month period falls outside this range, the company's rates are adjusted automatically to achieve the "adjusting point" ROE of 13.75 percent. Alabama Power's calculation of its actual return is reviewed by the Alabama Public Service Commission ("APSC"), but rate increases or decreases, if necessary, are made according to a pre-determined formula rather than through a formal rate case. Although the RSE plan is not a common form of incentive regulation,[36] it has many desirable features. In particular, it

[34] Alabama Public Service Commission ("APSC") (1982).

[35] APSC (1990).

[36] Plans like the RSE are called "sliding scale" plans because they "slide" rates up and down to stay within the specified rate-of-return "scale." Sliding scale plans generally define a deadband around a target rate of return and reset rates if earnings fall outside of this deadband. The first sliding scale plan was applied in 1906 (based on a recommendation by Louis Brandeis) to the Boston Gas Company for 10 years. A similar sliding scale plan was implemented for Potomac Electric Company between 1925 and 1955. These early experiments were
(continued...)

provides clear incentives and provides rewards for efficient utility operations, it is broad-based, it allows the company to focus its attention on managing its operations rather than the regulatory process, and it reduces administrative costs relative to COSR.

San Diego Gas & Electric Company:

SDG&E adopted broad-based incentive regulation in 1994 by implementing three separate PBR plans that applied to: (1) gas procurement costs (Gas Procurement PBR); (2) generation and purchased power costs (Generation and Dispatch PBR); and (3) the company's operating and capital costs (Base Rate PBR). These PBR plans, in effect for the years 1994 through 1998, adjusted allowed revenues based on cost indices and provided pass through of uncontrollable costs, service quality benchmarks, and earnings sharing. SDG&E's Base Rate PBR featured earnings sharing with a 100 basis point deadband around the company's target overall rate of return (equivalent to approximately 200 basis points around the target return on equity).[37] Customers shared 25 percent of the incremental returns between 100 and 150 basis points above the target return, and 50 percent of incremental returns between 150 and 300 basis points above the target overall rate of return on rate base. The plan also included downside sharing in which customers absorbed 50 percent of decremental returns between 150 to 300 basis points below the target return, and 100 percent for returns more than 300 basis points below target.

SDG&E's initial PBR plans were replaced in 1999 by a plan that applies to SDG&E's electric distribution and natural gas services.[38] The plan is a price cap with a four-year commitment period. It permits the pass through of uncontrollable costs and incorporates an automatic adjustment to the target rate of return (triggered by substantial interest rate changes), service quality benchmarks, and earnings sharing applied to the company's overall rate of return. The sharing provisions incorporate a deadband of 25 basis points (in which customers do not share earnings) and nine "progressive" sharing bands in which customers

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[36] (...continued)
discontinued during times of high inflation when increasing costs automatically led to increased rates. (See Biewald and Woolf, *et al.* (1997), p. 11).

[37] A capital structure of approximately 50 percent debt and equity means that the sharing bands defined in terms of the allowed returns on equity are effectively two-times as wide as the sharing bands defined in terms of the overall rate of return (*i.e.*, the return on debt and equity).

[38] California Public Utilities Commission ("CPUC") (1999).

share between 75 percent (for 25 to 50 basis points above the target return) and 5 percent (for 250 to 300 basis points above the target return) of incremental earnings. Above 300 basis points, customers do not share in the company's achieved earnings. This "reversed taper" in the sharing plan is designed to provide the company with particularly strong incentives to achieve large cost savings. Again, it is important to emphasize that California's current difficulties are caused by problems related to industry restructuring. The problems are unrelated to the implementation of incentive regulation.[39]

Central Maine Power Company:

CMP has operated under incentive regulation for a decade. After some less than satisfactory experiments with a "revenue-per-customer cap" plan,[40] the Maine Public Service Commission requested that CMP and interested parties negotiate an Alternative Rate Plan (ARP) in 1993. The negotiations produced a price cap plan that established a separate price cap for each customer class for a five-year period from 1995 to 1999.[41] This plan featured significant pricing flexibility, pass through of uncontrollable costs, and service quality benchmarks. The ARP also featured an earnings sharing schedule that allowed CMP's shareholders to retain 100 percent of the earnings and losses within a deadband of 350 basis points above and below the company's authorized ROE. Earnings above and below the deadband were shared equally with CMP's customers. The positive experience with this ARP led to the implementation of similar plans for the other regulated electric utilities in Maine.[42] Moreover, CMP and the Office of Public Advocate recently stipulated to an "ARP 2000" with a seven-year commitment period from 2001 through 2007.[43] The new ARP establishes a similar price cap plan for CMP's remaining state-regulated activities (*i.e.*, its distribution services), but imposes larger productivity offsets in exchange for eliminating the sharing of earnings above the target return.[44]

[39] See footnote 31 for a brief discussion of the nature of these problems.

[40] Initiated in 1991 to provide explicit incentives for energy efficiency, the plan was discontinued because it led to significant rate increases.

[41] Maine Public Utilities Commission ("MPUC"), 1995.

[42] See Bangor Hydro and Maine Public Service Company in Table 2 above.

[43] MPUC (2000).

[44] Under the ARP 2000, the productivity offset (*i.e.*, the X factor in the RPI-X price cap formula) is equal to (continued...)

IV. OBSERVED BENEFITS OF INCENTIVE REGULATION

This Section documents the benefits of incentive regulation as perceived by regulators with significant PBR experience. The Section also reviews the preliminary results of empirical research designed to quantify the impact of incentive regulation on industry performance. The many advantages of incentive regulation have led regulatory commissions with substantial electric utility PBR experience to endorse incentive regulation enthusiastically. Moreover, empirical evidence from the telecommunications industry suggests that incentive regulation has certainly not harmed customers, and likely has provided significant benefits to customers and regulated companies alike. These benefits from PBR include lower prices, consistent levels of service quality, increased network modernization, and higher earnings.

A. COMMISSIONS' ASSESSMENT OF INCENTIVE REGULATION

This section summarizes perspectives on incentive regulation offered by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions in Alabama, California, and Maine. These three state commissions were among the first to implement broad-based incentive plans for electric utilities.

Alabama Public Service Commission:

The Alabama Public Service Commission (APSC) approved Alabama Power's RSE plan in 1982. The Commission endorsed the plan as a:

> significantly improved method of setting electric utility rates sufficient to provide the Company with stable and adequate returns, to provide the public with the lowest possible rates consistent with the cost of service, to ameliorate the impact of increases required, and to decrease rates promptly if the designated rates of return are exceeded.[45]

When reviewing Alabama Power's RSE for the second time in 1990, the APSC concluded that:

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44 (...continued)
inflation in the first year and ranges between 2.0 percent and 2.9 percent in the subsequent years.

45 APSC (1982), pp. 5-6.

[m]uch of the company's success has come as a result of the stability provided by RSE. The company has utilized that stability to focus on the implementation of cost control and efficiency measures which will allow the Company to perform well in the future.[46]

The APSC specifically stressed the increased benefits of RSE as compared to traditional cost-of-service regulation:

[p]rior to the implementation [of the RSE plan] in December of 1982, Alabama Power Company operated in a state of uncertainty. The Company was constantly before the [APSC] seeking rate increases to help offset an extremely low rate of return. Both private investors as well as industry analysts perceived the Company as somewhat risky, primarily because of the below average return on equity. As a result, Alabama Power experienced difficulty in obtaining the financing necessary to operate efficiently. These long, drawn-out rate cases were extremely expensive and time-consuming for both the Company and the [APSC]. Rate RSE was developed to eliminate some of the inherent problems of traditional utility regulation. RSE combines the general, underlying concepts of traditional utility regulation with implementation procedures which avoid the pitfalls of regulatory lag and the expenses associated with traditional ratemaking procedures. Alabama Power is now able to devote its time to the efficient operation of the Company."[47]

California Public Utility Commission:

Despite its recent problems related to restructuring, California has accumulated significant positive experience with the incentive regulation of electric utilities.[48] PBR had particular appeal in California because the state's investor-owned utilities had rates among the highest in the country and the region.[49] The California Public Utility Commission (CPUC) first supported the use of broad-based PBR in 1993. Shortly thereafter, in Rulemaking 94-04-031, the CPUC "proposed that performance-based regulation replace cost-of-service regulation for those electric utilities not fully subject to competition."[50] In the CPUC's policy decision on restructuring, issued in January of 1996, the CPUC concluded that:

Existing cost-of-service regulation has become too complex and difficult in many ways to allow us to regulate the utilities properly in this fast-moving industry. Our goal is to have an improved regulatory process that offers

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46 APSC (1990), p. 7.

47 *Ibid.*, p. 8.

48 Again, see footnote 31 for a brief comment on the nature of California's restructuring problems.

49 Biewald and Woolf, *et al.* (1997), p. 25.

50 CPUC (2000).

flexibility and encourages utilities to focus on their performance, reduce operational cost, increase service quality, and improve productivity. At the same time, we must ensure that safety, quality of service, and reliability are not compromised. *There is broad but not universal consensus that Performance Based Ratemaking (PBR) can accomplish these objectives by providing clear signals to utility managers with respect to their business decisions and helping them make the transition from a tightly regulated structure to one that is more competitive.* Under PBR, utility performance is measured against established benchmarks. Superior performance, above the benchmark, would receive financial rewards, and poor performance would result in financial penalties to the shareholders. *By providing financial incentives to utilities, we will encourage them to operate more efficiently to maximize their profits.*[51]

SDG&E's initial PBR plan was credited with several successful outcomes. In particular, SDG&E's realized operating costs and capital expenditures were lower than projected while the plan was in effect. According to the company's 1994, 1995, and 1996 Annual Reports, SDG&E reduced its O&M costs below the authorized level by between $15 and $19 million.[52] Regulatory costs also declined substantially, since the PBR plan required only two annual filings: an advice letter that provided the Company's calculation of its authorized revenue requirement, and an annual report which summarized SDG&E's performance in the previous year and provided a computation of rewards and penalties. The review of these filings was fairly perfunctory. SDG&E also out-performed its safety and customer satisfaction benchmarks in 1994-1996.[53] When the Commission adopted a similar PBR for the transmission and distribution services of Southern California Edison ("SCE") in 1996, it stressed that:[54]

> Allowing the utility to retain some of the net revenue from cost reduction efforts also resembles the competitive market where a firm can increase its profits by lowering its costs."[55]

In addition to the restructuring-related rate case moratoria for SCE and Pacific Gas & Electric, price cap regulation is currently applied to the distribution functions of SDG&E

51 CPUC (1995) as modified by CPUC (1996a), pp. 85-86 (emphasis added).

52 Biewald and Woolf, *et al.* (1997), p. 27.

53 Biewald and Woolf, *et al.* (1997), p. 27.

54 CPUC (1999).

55 CPUC (1996b), p.8.

and SCE.[56] In its Order approving SDG&E's distribution PBR, the California Commission specifically made the following findings of fact:

1. We have long considered incentive-based regulation superior to command-and-control regulation and have established several goals to be addressed by incentive regulation for energy utilities.
2. Performance-based regulation can provide stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices [for the regulated services].
3. Performance-based regulation can simplify regulation and reduce administrative burdens in the long term, without sacrificing service, safety, and reliability.
4. Incentive regulation can prepare utilities to operate effectively in the increasingly competitive energy utility industry.[57]

Maine Public Utility Commission:

The Maine Public Utility Commission ("MPUC") first approved an Alternative Rate Plan ("ARP") for CMP in 1995.[58] The MPUC expected the ARP to provide "a high degree of stability and predictability in electric rates for CMP customers"[59] and saw it as "a positive step away from the imperfect surrogate to market pressures provided by more traditional regulation, to a more direct link between performance and profits."[60] The MPUC stated that a multi-year cap plan offered the following benefits:

1. electricity prices continue to be regulated in a comprehensible and predictable way;
2. rate predictability and stability are more likely;
3. regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities operations;
4. risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and

56 CPUC (2000).

57 CPUC (1999), pp. 65-66.

58 Biewald and Woolf, *et al.* (1997), p. 16.

59 MPUC (1995).

60 *Ibid.*

5. because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.[61]

At the time of its mid-period review, there was a consensus that the ARP was working well for both CMP's customers and shareholders: controlling rates, providing sufficient earnings, creating a more market-driven focus, retaining load, maintaining service quality, and significantly reducing litigation.[62] In response to the positive results, CMP and the Office of Public Advocate agreed to stipulate to a second ARP starting in 2000. In approving the new plan, the MPUC also reaffirmed its 1995 finding that the PBR plan "will likely produce just and reasonable rates."[63]

Federal Energy Regulatory Commission:

FERC's Office of Economic Policy first stressed the advantages of incentive regulation compared to traditional cost-of-service regulation in a 1989 technical staff report.[64] The FERC's 1992 Policy Statement on Incentive Regulation first noted the Commission's receptiveness to PBR plans proposed by public utilities as well as natural gas and oil pipelines.[65] Most recently, the FERC has specifically supported and encouraged PBR for the regulation of transmission services. In its Order No. 2000,[66] which encourages the voluntary formation of Regional Transmission Organizations ("RTOs"), the FERC notes that of those who commented on the preceding Notice of Proposed Rulemaking, "the vast majority of commenters favor PBR of some form to promote efficient operations by RTOs."[67] These commenters included a wide range of market participants, including state regulatory commissions, and noted economists, such as Paul Joskow. Noting that PBR should be voluntary for RTO participants, the FERC concluded:

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[61] MPUC (1993), p. 144.

[62] Biewald and Woolf, *et al.* (1997), p. 17.

[63] MPUC (2000), p. 13.

[64] Brown, Einhorn, and Vogelsang (1989).

[65] FERC (1992).

[66] FERC (1999) ("*Order 2000*").

[67] *Order 2000*, p. 534.

> At the outset, we think it is important to emphasize that PBR is far from a new concept. Over the last 10 to 20 years, a significant amount of research, primarily by economists, has been done regarding the conceptual basis of, and efficient designs for, PBR. This research addresses its use in the electric utility industry as well as other regulated industries. . . .
>
> *PBR will allow the Commission to rely on market-like forces, to the maximum extent possible to create incentives for RTOs to efficiently operate and invest in the transmission system.* This does not mean that we expect that transmission service will be provided in a competitive market any time soon, or at all. We recognize that transmission service will retain most or perhaps all of the characteristics of a natural monopoly for the foreseeable future, and that some type of explicit price regulation will therefore be required to prevent monopoly abuse. But we believe that *PBR, especially if accompanied by explicit and well-designed incentives, may provide significant benefits over traditional forms of cost-of-service regulation.*[68]

The FERC notes that rate case moratoria "where transmission rates are locked into their current levels for a limited period of years [fall] within the concept of PBR."[69] The FERC also advises that "the benefits of PBR should be shared between the RTO and its customers," while recognizing that earnings sharing can reduce "the strength of the incentives faced by the RTO."[70] Since Order 2000 was issued, a number of incentive plans have been proposed in the context of utilities' recent RTO filings. These plans still await FERC's approval.

These observations by regulatory commissions with significant experience with incentive regulation demonstrate that the advantages of incentive regulation discussed in Section II.C can indeed be realized in the electric utility industry.

B. EMPIRICAL EVIDENCE ON PBR BENEFITS IN TELECOM

Although the advantages of incentive regulation are widely recognized, it is very difficult to measure precisely the impact that alternatives to COSR have had on the performance of regulated entities.[71] At a minimum, careful empirical analysis of PBR requires extensive

68 *Order 2000*, pp. 537-38 (emphasis added).

69 *Order 2000*, pp. 539-40.

70 *Order 2000*, p. 546.

71 It is difficult to quantify the incremental impact of incentive regulation for at least three reasons. First, the (continued...)

data on many dimensions of performance over a long time period in which both PBR and COSR are implemented.

In the U.S. electric utility industry, the data and experience required to quantify precisely the impact of incentive regulation are not currently available. However, several studies have been undertaken to measure the impact of broad-based PBR plans in the telecommunications industry.[72] These studies include estimates of the impact of incentive regulation on prices, operating costs, productivity, earnings, service quality, network modernization, and universal service. One group of authors who reviewed a number of empirical studies on this subject concluded: "while most studies suggest that incentive regulation is achieving important goals, the measured impact of regulatory reform varies widely across studies."[73] Despite these differences, the studies generally show that customers are at least as well off under PBR as under cost-of-service regulation. More importantly, many of the studies also suggest that customers and regulated companies alike have benefitted significantly from incentive regulation.

A number of studies report that rates for telecommunications service have declined under incentive regulation. Crandall and Waverman (1995) find prices for local service to be lower by approximately 10 percent under price cap regulation than under COSR regulation between 1987 and 1993. Magura (1998) concludes that incentive regulation may be associated with as much as a 17 percent decline in local service rates between 1987 and 1994 relative to COSR. Similarly, Kaestner and Kahn (1991) find that AT&T's intra-state toll prices were 18 percent lower in states with incentive regulation and pricing flexibility than in states with cost-of-service regulation. Tardiff and Taylor (1993) report that intraLATA toll rates for companies in states with some form of incentive regulation tend to

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71 (...continued)
impacts of PBR plans are usually not realized immediately. Therefore, empirical studies conducted soon after the implementation of the incentive plan may not capture their full effects. Second, to isolate the impact of incentive regulation, one needs to control for all other factors that might affect performance. In practice, such perfect control is difficult, if not impossible. Third, once COSR is replaced by an alternative regulatory regime, one cannot be certain of the performance that would have occurred under COSR. See Sappington and Weisman (1996c) for a more detailed discussion of the difficulties in measuring the impact of incentive regulation.

72 For a review of the empirical literature see Kridel, Sappington, and Weisman (1996).

73 Kridel, Sappington, and Weisman (1996), p. 301. For more recent studies, see Resende (1999), Ai and Sappington (1998), and Magura (1998).

be lower by 4 to 8 percent, while there was no measurable effect of incentive regulation over COSR with respect to local rates.

The available empirical evidence also suggests that even highly-powered incentive regulation plans have not caused service quality to decline systematically.[74] Ai and Sappington (1998) find that during the mid-1990s, the regional Bell Operating Companies ("RBOCs") remedied reported service problems somewhat more slowly under PBR. However, residential and business customers both registered fewer complaints with their public utility commissions under PBR, suggesting an increase in customer satisfaction and perceived service quality.

A number of empirical studies have also documented a significant relationship between incentive regulation and network modernization. For example, Greenstein *et al.* (1995) report substantial increases in the deployment of fiber optic cable and switching equipment under PBR and price cap regulation between 1986 and 1991. Ai and Sappington (1998) also report a significant impact of incentive regulation on network modernization between 1992 and 1996.

The empirical evidence also suggests that PBR has provided gains in productivity and earnings. For example, Tardiff and Taylor (1993) estimate that the total factor productivity growth rate of large telecommunications firms in the U.S. increased by 2.8 percentage points under incentive regulation prior to 1992. They attribute this increase in roughly equal parts to an increase in the growth rate of outputs and to a decrease in the growth rate of inputs under incentive regulation. Magura (1998) suggests that fixed costs may have declined substantially under incentive regulation between 1987 and 1994; but Ai and Sappington (1998) find little effect of incentive regulation on reported operating costs between 1991 and 1996. The Federal Communications Commission (1992) reports that AT&T's average annual rate of return increased by approximately one percentage point during the early years of price cap regulation. Ai and Sappington (1998) find that earnings increased by approximately 10 percent under price cap regulation relative to COSR, but the increases under other forms of incentive regulation were not significant.

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[74] AT&T experienced some large-scale outages while operating under price cap regulation in 1990 and 1991, but the FCC (1992) concluded that these outages were not due to the price cap regulation plan under which AT&T operated.

In summary, the empirical evidence from the U.S. telecommunications industry suggests that incentive regulation has delivered meaningful benefits. While benefits of identical magnitude are not certain in the utility industry, the empirical evidence from the telecommunications industry demonstrates that PBR can deliver: (1) lower prices; (2) increased network modernization; and (3) higher earnings; with (4) no pronounced reduction in overall service quality. These findings illustrate the important point that a regulated company's increased earnings need not come at the expense of higher rates or reduced service quality. When properly motivated to do so, companies can find ways to lower rates *and* increase earnings, thereby creating a win-win situation for both customers and the companies serving them.

V. ATTRIBUTES OF WELL-DESIGNED INCENTIVE REGULATION

PBR plans must be designed carefully if they are to achieve their full potential. Incentive regulation is more likely to deliver significant benefits to all parties if the plan: (1) is transparent and easy to understand; (2) provides proper motivation and scope (in the sense that it relates to the firm's entire operation and to elements that are in fact under managerial control); (3) balances risks and rewards to achieve operationally and politically acceptable outcomes; and (4) instills confidence that all of its terms and conditions will remain in effect for the entire commitment period. This section will discuss the key trade-offs inherent in designing a PBR plan that satisfies all of these criteria.

Transparency and Simplicity:

Both the broad principles and the specific details of any incentive regulation plan should be transparent, unambiguous, and easily understood. These features of a plan will increase acceptance by various interest groups, reduce the likelihood of disputes about implementation details, and reduce the associated administrative burdens.

Some forms of incentive regulation are inherently simple. There is little ambiguity, for example, about the meaning of a multi-year rate freeze.[75] But price cap plans can be more complex. As explained above, price cap plans typically permit rates to rise at the general inflation rate, as measured by the CPI or GDP deflator, less a fixed productivity offset. The CPI and GDP deflator are widely used measures of inflation and so engender little controversy. But the origin of the productivity offset (or X factor) can be more mysterious, and so warrants careful consideration and justification.

Earnings sharing plans state explicitly the proportion of earnings increases that will be delivered to customers and the form in which the shared earnings will be delivered. However, the measurement of earnings can introduce controversy. To limit controversy, earnings sharing plans should explain clearly and as simply as possible the rules for measuring earnings. Transparent and simple rules must also be employed to define all other elements of an incentive plan, including permissible price variation and service quality requirements, for example.

It is difficult for even the simplest and most transparent incentive plan to eliminate disputes altogether. Controversy is particularly difficult to avoid during the initial commitment period and when the plan is revised for the first time. The frequency and severity of disputes will generally be more limited for simpler, transparent plans, however. At the end of each commitment period, every effort to address disputed matters for subsequent commitment periods is advised in order to reduce the likelihood of future controversy.

Proper Motivation and Scope:

It is important that incentive regulation plans link financial rewards to dimensions of a company's aggregate performance over which the company's management has substantial control. Financial rewards that focus narrowly on limited dimensions of performance (such as power plant availability) can encourage excessive attention to the specified dimensions and insufficient attention to other important dimensions of performance. In contrast, broad-based plans—such as rate freezes, rate case moratoria, price caps, and earnings sharing plans—encourage a company to lower its total operating costs, and not simply to reduce

[75] Rate freezes usually make exceptions for "extraordinary" expenses. To avoid disagreements, such expenses should be defined as completely as possible in advance.

certain elements of its costs. By avoiding undue focus on specific performance dimensions, broad-based incentive plans motivate a company to identify the best means to improve its operations, and thereby relieve regulators of any need to micro-manage the operations of the regulated firm.

If multiple distinct incentives are implemented (*e.g.*, one to encourage cost reduction and another to encourage service quality or reliability), the joint effect of these incentives must be analyzed carefully to ensure that they do not work at cross purposes. Otherwise, poorly coordinated and overlapping multiple incentives may cause the same problems those narrowly targeted incentives can cause.[76]

While incentives should have a broad focus, they should be limited to elements that are under management control. There is little to be gained by holding the regulated firm responsible for the consequences of events that are entirely beyond its control. Costs that are typically regarded as being beyond the firm's control include significant compliance costs resulting from new environmental legislation, unavoidable costs due to storm damage, or costs associated with changes in taxes or accounting rules. Incentive plans generally include pass-through provisions (often referred to as "Z" factors) which enable a company to recover unexpected costs that are beyond its control. To limit extended regulatory hearings to determine whether a particular cost was controllable or uncontrollable, disputed costs are often required to exceed a specified threshold before they are eligible for pass through.

Balance of Risks and Rewards:

Incentive regulation plans should provide the prospect of enhanced benefits for shareholders and customers alike. A careful balancing of risks and rewards is important in this regard. The firm must be given a fair opportunity to recover its costs and earn a return consistent with the risks it faces under the regulatory plan. Customers, in turn, should also enjoy the prospect of reasonable, predictable rates. Certain limits on earnings and rate increases are often appropriate to avoid politically and operationally unacceptable outcomes. Earnings sharing provisions can be useful in this regard. Of course, any earnings sharing plan must

[76] Multiple incentives can also challenge the transparency and simplicity of a PBR plan and invite misunderstanding and ambiguity.

also provide meaningful incentives to the regulated firm if it is to induce superior performance.

Incentive regulation imposes additional risks on the regulated firm. Increased opportunity to earn higher returns is appropriate to balance the increased risk. If incentive regulation imposes asymmetric risks under which customers share realized gains (*e.g.*, through sharing of realized performance gains) but bear no downside risk (*e.g.*, the risk of low earnings), then expanded opportunity for the company to earn higher returns is important to ensure that the risks and rewards it faces are commensurate.

Term and Commitment:

The duration of any incentive plan should be stated clearly in advance. Furthermore, all parties must abide by all terms and conditions of the plan for its entire duration. There may be circumstances under which the plan is reviewed and perhaps modified prior to its scheduled expiration. But these circumstances, and the nature of the ensuing review and potential modifications, should be stated clearly in advance.

A sufficiently long commitment period and clearly defined commitment terms are essential if an incentive plan is to provide meaningful incentives to improve performance, reduce administrative costs, avoid regulatory gaming by affected groups, and allow the company's management to switch its attention from managing the regulatory process to improving its performance. Short commitment periods can undermine incentives to improve long-term performance, as many initiatives with pronounced long-term benefits do not increase short-term profit. Incentives for improved long-term performance can be particularly dulled if a high proportion of the benefits of the improved performance are shared with customers during the commitment period.

PBR plans can only provide meaningful incentives to enhance performance if the regulated firm is confident that promised rewards will, in fact, be delivered. Unscheduled reviews, adjustments based on "Monday morning quarterbacking," and other attempts to appropriate achieved realized gains must be avoided. In particular, any perceived attempt to appropriate retroactively benefits that have been promised to the company during the PBR plan's commitment period will undermine the viability of future regulatory plans. Furthermore, unbridled attempts to extract all realized benefits from the regulated firm at the end of the commitment period—such as a reversal to stringent cost-of-service rates that do not properly balance risks and rewards and that appropriate all achieved incentives on a going forward basis—will dull incentives for superior performance, much as COS regulation does.[77]

In general, the longer the commitment period, the stronger the incentives are to achieve substantial improvements in long-term performance. While very long commitments can increase the likelihood of outcomes that are politically or operationally unacceptable (*e.g.*, excessive or inadequate earnings), a commitment period of moderate length (*e.g.*, five years), coupled with well-designed earnings sharing rules and clearly defined pass-through provisions, can provide strong incentives while minimizing the risk of unacceptable outcomes. It is also important to specify clearly how the incentive regulation plan will be monitored and how it will be reviewed and adjusted at the end of the commitment period, in order to improve long-term incentives, reduce regulatory uncertainty, and avoid contentious disputes.

VI. ASSESSMENT OF UNION ELECTRIC'S EARP

This section first describes UE's Experimental Alternative Regulation Plan (EARP) and evaluates the plan, in part by comparing it to other incentive regulation plans. This section also provides a preliminary evaluation of customer benefits achieved under the EARP.

A. DESCRIPTION OF UE'S EARP

UE's initial EARP settlement took effect on July 1, 1995, and allowed for possible modification after three years. Under the 1995 settlement, UE reduced its rates by $30 million and provided an additional up-front customer credit of $30 million. A moratorium on rate increases then froze average retail rates at the reduced rate levels through August 31, 1998. The plan also instituted earnings sharing under which UE could retain all earnings

[77] A reassessment of incentive plans based on cost-of-service rates should, thus, specifically recognize the *full range* of companies' and intervenors' cost of service recommendations. To avoid the perception of retroactive appropriation of companies' PBR benefits, regulators may want to be careful to avoid low estimates of the firm's future cost of service, particularly when the firm has worked diligently and successfully to improve performance.

up to an ROE of 12.61 percent. Incremental earnings between 12.61 and 14 percent were shared equally between UE and its customers. All earnings in excess of 14 percent were passed through to customers. Hence, the maximum ROE that UE could earn under this plan was approximately 13.31 percent. UE's earnings were reported monthly and reviewed on an annual basis to determine if sharing was necessary. Shared amounts were passed on to customers in the form of "sharing credits" on customers' utility bills. Customers were not required to share any potential burden associated with low earnings. However, UE was permitted to initiate a rate increase case if its realized return on equity dropped below 10 percent for a 12-month period, or if the Company faced a major adverse event.

UE's EARP was extended with slight modifications for a second three-year period starting July 1, 1998. This new three-year commitment, part of a broader merger-related settlement, required UE to reduce its rates by an amount equal to the weather-normalized average annual sharing credits that customers received during the first three-year EARP period. Rates are frozen at this lower level through the end of the commitment period—June 30, 2001. These rates will remain in effect after the expiration of the three-year EARP period until they are changed in the context of a new settlement or through a rate case before the Missouri Public Service Commission (MPSC). A slightly modified form of earnings sharing was adopted as well. UE could, again, retain all earnings up to an ROE of 12.61 percent and half of all incremental earnings between 12.61 and 14 percent were again delivered to customers. However, UE could now also retain 10 percent of the incremental earnings between 14 and 16 percent. Earnings in excess of a 16 percent ROE are awarded fully to customers. Thus, the maximum ROE that UE could earn under the EARP increased to 13.51 percent. Again, UE customers are not required to share the potential burden of low earnings—although UE is permitted to seek a rate increase during the three-year EARP period if its ROE falls below 10 percent for a 12-month period or if the Company faces a major adverse event.

UE has combined its EARP with management and employee performance incentives that are tied to the Company's earnings per share. These broad employee performance incentives help to spread the beneficial incentives provided by the EARP to all levels of the organization, thereby enlisting the support of all personnel in the ongoing effort to improve performance. These benefits of improved performance then accrue customers and shareholders alike.

B. Comparison of UE's EARP to Other Incentive Plans

UE's current EARP, like its predecessor, is a widely-used form of incentive regulation that combines a rate case moratorium with earnings sharing. UE's EARP is simpler than most price cap plans, but it is able to provide many of the same benefits.

The EARP's design parameters are generally comparable to those in many other plans, but are notably conservative in some respects. For example, the EARP's commitment period of three years is relatively short. The typical commitment period in PBR plans ranges from three to seven years. The relatively short commitment period limits the risk of adverse unanticipated outcomes, but it also reduces the Company's incentive to improve performance by limiting the time period over which the Company can expect to share achieved benefits. Because the EARP does not include any provisions that allow the pass through of uncontrollable costs, the short three-year commitment period may be reasonable. However, UE's ability to initiate a new rate case if adverse conditions arise is a poor substitute for pass-through factors. There are two reasons for this conclusion. First, if UE requests a rate case, the EARP is terminated, and so is the time period over which the Company can retain achieved earnings benefits. This will eliminate the incentives that otherwise would prevail through the entire commitment period. Second, relevant timing considerations impose significant cost recovery risks on the Company. The Company is only permitted to file a rate increase case after it has suffered through 12 months of sub-par earnings. Furthermore, the rate case is likely to take approximately a year to complete. Consequently the Company may well be required to bear the full earnings shortfall (*i.e.*, without customer sharing of such adverse outcomes) for two years.

The earnings sharing provisions in the EARP are quite conservative in several respects. First, the "deadband" in which no sharing occurs is relatively narrow—only reaching up to 12.61 percent. At that threshold, the sharing starts at a high initial rate of 50 percent. As earnings rise further, customers quickly receive ever-increasing shares of these earnings, limiting UE's maximum return on equity to only 13.5 percent. This maximum possible return represents only the upper end of financial experts' estimated range for regulated utilities' cost of equity.[78] Many PBR plans provide significantly greater up-side earnings potential (*e.g.*, Alabama Power's RSE plan limits earnings to 14.5 percent). Some other plans do not truncate the up-side potential at all. This is the case under SDG&E's incentive plans and the 1995 and 2000 ARPs for Central Maine Power, for example. And under the rate and earnings sharing provisions applicable during the transition to "customer choice" in Illinois, Ameren's CIPS-UE operations are required to share 50 percent of earnings above of a ROE threshold, without a cap on total achievable returns. For 2001, CIPS-UE's ROE threshold is 14.5 percent.

The EARP also differs from other PBR plans in that it does not afford the Company any pricing flexibility. However, given UE's relatively low rates for electric utility service and the absence of significant industry restructuring in Missouri, the lack of pricing flexibility may not be a strong handicap. Similarly, the absence of specific service quality standards in the rate plan appears to have been of little consequence—UE's customer satisfaction ratings are above the national average and have not declined since implementation of the EARP in 1995.

In addition to the monitoring provisions of the EARP that require monthly reports and detailed annual reviews, Union Electric is also exposed to a full "revenue cost of service audit" starting almost a year prior to the end of the three-year commitment period. This provision shortens the effective commitment period of the EARP. The provision also requires the expenditure of considerable Company and Commission Staff resources—thereby limiting the extent to which the EARP can reduce regulatory/administrative costs below the levels incurred under cost-of-service regulation.

[78] For example, Union Electric's cost of capital witness in the Company's recent natural gas rate case concluded that a conservative estimate of the Company's fair return on equity ranged from 12.75-13.0 percent. (Direct Testimony of Kathleen C. McShane, March 27, 2000.) Similarly, The Brattle Group recently estimated that the required return on equity for Pacific Gas & Electric's distribution business was in the range of 12.5 percent to 13.5 percent. (Direct Testimony of A. Lawrence Kolbe, May 8, 2000).

C. Preliminary Evaluation of Consumer Benefits Under the EARP

A preliminary evaluation shows that the EARP settlements have benefitted Union Electric's customers in several ways. First, the settlements have reduced rates twice without the significant resource and time requirements associated with fully litigated rate cases. As a result of the first EARP settlement, Union Electric permanently reduced its Missouri retail rates by $30 million starting in August 1995. And in April 2000 (retroactive to September 1998), the second EARP settlement permanently decreased retail rates by an additional $16 million. Moreover, the first EARP settlement provided up-front customer credits of $30 million in July 1995. It is important to note that, in addition to being substantial, these benefits have been delivered to customers in a timely manner. Up-front rate reductions and credits ensured that customers received immediate gains, regardless of the firm's realized performance. In contrast, UE was required to earn its rewards through improved performance, and the rewards accrued only after the benefits of improved performance were earned.

In addition to these permanent rate reductions and up-front credits, the EARP also provided rate stability and substantial sharing credits to Union Electric's customers. In contrast to traditional cost-of-service regulation, the EARP provided customers with a high level of certainty that rates would not increase during the three-year commitment periods. At the same time, the EARP also provided customers with the prospect of sharing in the success of UE's performance gains.

Customers have already received $44 million in earnings sharing credits for the first year of the EARP, $18 million for the second year, $26 million in the third year, and $20 million in the fourth year (*i.e.*, the first year under the second EARP settlement). The Company's earnings report filed in October 2000 indicates that $18 million would be credited in the most recent year. Again, customers have benefitted not only from the amount of these sharing credits, but also from their timely receipt. Under traditional cost-of-service regulation, customers would not have been able to enjoy any such benefits until after the conclusion of a rate case. And, of course, there is no guarantee that these benefits would have been generated under cost-of-service regulation.

Table 3 summarizes the cumulative effect of EARP-related rate reductions, up-front credits, and sharing credits. These EARP-related payments and rate reductions have combined to deliver $409 million in benefits to customers, relative to what they would have paid under the retail rates that were in effect prior to the EARP. This does not include benefits that customers received from merger-related concessions under the second EARP settlement. These concessions include UE's agreement not to seek recovery of its $232 million merger premium from its merger with CIPSCO, and to abandon its proposal that shareholders receive half of the nearly $760 million in merger-related savings.

Table 3
EARP-related Rate Reductions and Customer Credits

EARP Period	Annual Savings from Permanent Rate Reductions		Up-Front Credits	Sharing Credits	Total
1995/96	$30 million	--	$30 million	$44 million	$104 million
1996/97	$30 million	--	--	$18 million	$48 million
1997/98	$30 million	--	--	$26 million	$56 million
1998/99	$30 million	$16 million	--	$20 million	$66 million
1999/2000	$30 million	$16 million	--	$18 million	$64 million
2000/01	$30 million	$16 million	--	$25 million[79]	$71 million
Total	$180 million	$48 million	$30 million	$151 million	**$409 million**

These dollar amounts do not necessarily reflect the benefits that UE's customers have received under the EARP *relative* to the rates that they would have paid under cost-of-service regulation. A calculation of EARP benefits relative to traditional cost-of-service rates is very difficult, because it is impossible to identify precisely the rates that customers would have paid in 1995 through 2001 in absence of the EARP settlements. It is important to emphasize, however, that *Union Electric's current cost of service may be substantially lower than it would have been had the Company been operating under traditional cost-of-service regulation.* This is because the EARP has provided Union Electric with a stronger incentives to improve performance. Union Electric's Chief Financial Officer, Donald E.

[79] Estimated based on previous years' average.

Brandt, clearly illustrated in testimony how the EARP has changed the very perspective of UE's management and employees:

> There are a couple items I think are very critical to the issue at hand. The most important has been the use of this [EARP] agreement, the two agreements in helping to change the culture of the Company. . . [I]t's my job to beat on people about cost. . . [But employees] said, every time we reduce costs, the Commission comes and takes it away. [T]hat's the way the cost-of-service model rate base regulation works,. . .that's a disincentive. And when we got this plan in place, I made speech after speech. . . Here's your opportunity, folks. This is as close to competition I can get you right now, but you make a dollar and we get to keep half of it. It goes to the bottom line. And again, regardless of whether I'm talking to a vice president or a pipefitter in one of our power plants, that's had an effect, and I've seen that effect. . .It's good for the shareholders and it's good for customers. I know that sounds trite, but that rings a bell when it comes to employees.[80]

As noted, UE has combined the EARP with broad employee incentive programs that encourage cost reductions and cost control throughout the Company.

Table 4 provides additional evidence that UE's customers have enjoyed relatively low rates under the EARP. The table reveals that the *average rates* that Union Electric's customers paid during the EARP (*i.e.*, including the benefits of EARP-related rate reductions and sharing credits) were *4.8 percent lower* in 1999 than the average rates they paid in 1994, prior to the implementation of the EARP. During the same time period, average consumer prices (as measured by the CPI) have increased 12.4 percent. The table also shows that both on average and within each customer class (*i.e.*, residential, commercial, and industrial), UE's customers pay less for electric service today than they did six years ago.

Table 4 shows that *UE's customers enjoyed greater reductions in average electricity rates than customers of other utilities in the Midwest.* For example, between 1994 and 1999, the average rates of electric utilities in the West-North-Central census region of the U.S. (which includes all utilities in Iowa, Kansas, Minnesota, Missouri, South Dakota, and North Dakota) increased by 0.5 percent. Average rates of electric utilities in the East-North-Central census region of the U.S. (which includes all utilities in Illinois, Indiana, Michigan, Ohio, and Wisconsin) decreased by only 2.3 percent between 1994 and 1999. But during the same period, UE's average rates decreased by 4.8 percent. Table 4 also shows that Union Electric's customer classes each received a larger rate reduction during the EARP

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[80] Brandt (1999), transcript, pp. 266-67.

period than the corresponding rate reduction delivered, on average, by other Midwest utilities.

Table 4
Relative Changes of Union Electric's Retail Rate during the EARP Period

Rate Comparison by Customer Class	Average Retail Rates (includes customer credits) in cents/kWh		1994-99 Percentage Change in Average Retail Rates[81]
	1994	1999	
UE-Missouri			
Residential	7.53	7.22	– 4.1%
Commercial	6.23	5.94	– 4.7%
Industrial	5.06	4.72	– 6.7%
All Customers	6.48	6.17	– 4.8%
West-North-Central			
Residential	7.49	7.44	– 0.7%
Commercial	6.36	6.11	– 3.9%
Industrial	4.36	4.39	0.7%
All Customers	5.80	5.83	0.5%
East-North-Central			
Residential	8.52	8.25	– 3.2%
Commercial	7.37	7.15	– 3.0%
Industrial	4.76	4.57	– 4.0%
All Customers	6.59	6.44	– 2.3%

Source: EEI (2000), EEI (1997).

Table 4 documents that UE's customers received substantial benefits during the EARP period. The table indicates that UE's Missouri retail rates have decreased by 2.5 to 5.2 percentage points *more* than the average retail rates of other Midwest utilities. Since UE's total retail revenues in Missouri are roughly $2 billion, these results suggest that annual expenditures by UE's customers may have already declined between $50 million to $100

81 Based on data and weighted averages as reported by EEI. Note, however, that average rates by customer class may be based on fewer data points in cases in which customer class data is not available for all of the utilities that report company-wide average rates. The average across all customer classes, thus, may not be fully consistent with the averages reported for individual customer classes.

million *more* than they would have had UE achieved only the average rate reduction of other Midwest utilities.

These rate comparisons do not necessarily quantify definitively the extent to which Union Electric's EARP has benefitted Missouri customers *relative* to traditional COSR. However, these rate comparisons suggest that the incentives provided by the EARP may well have resulted in an outcome under which customers are significantly better off than they would have been under traditional cost-of-service regulation. These significant gains suggest that the continuation of the EARP merits serious consideration. A return to cost-of-service ratemaking—or a resetting of UE's retail rates based on overly aggressive cost-of-service standards—would undermine the improved incentives under which Union Electric has been able to operate since 1995. Given the significant benefits that customers have enjoyed under the EARP, such action would not appear to be in the public interest.

Finally, it is important to note that EARP-related customer benefits have not come at the expense of reduced customer satisfaction or service quality. We have briefly explored this subject area based on residential customer survey data for "earned loyalty" from 1994-1999.[82] The degree of "earned loyalty" is a frequently-used metric in customer satisfaction surveys which, in turn, is an important measure of perceived service quality. In carefully controlled surveys, customers rate on a scale of 1 through 7 whether the local utility company has earned their loyalty as a customer.[83] The proportion of responses with a rating of 6 or 7 is used as an indicator of strong customer satisfaction. These data show that Ameren/Union Electric's "earned loyalty" ratings have remained at the Company's 1994 level of 54 percent—well above the national average, which decreased from 45 percent in 1994 to 43 percent in 1999.

[82] The surveys for Ameren/Union Electric were conducted by Cambridge Reports/Research International. To allow for a relative assessment of Ameren/Union Electric's performance, Cambridge Reports also made available national averages based on EEI national residential survey results.

[83] A rating of 1 means the company "definitely has not earned my loyalty" and 7 means the company "definitely has earned my loyalty."

D. POTENTIAL ENHANCEMENTS TO THE EARP

Parties to the EARP settlement are currently assessing whether Union Electric's EARP "should be continued as is, continued with changes (including new rates, if recommended) or discontinued."[84] Based on our review of the current settlement, six potential enhancements seem to merit serious consideration for the continued operation of Union Electric's incentive regulation plan under a new EARP settlement.

First, the commitment period might be extended. Extending the commitment period to, for example, four or five years would enhance incentives to improve long-term performance.

Second, the deadband range of no sharing and the range of 50-50 earnings sharing might be increased. A wider deadband and wider sharing bands would further increase incentives to improve performance.

Third, a longer commitment period should be combined with pass-through provisions for significant changes in uncontrollable costs (or benefits) associated with certain exogenous events. The likelihood of terminating the EARP in mid-stream could be reduced substantially by adding such pass-through provisions. Relevant events include natural disasters, significant changes in taxes, environmental laws, and federal regulation of Union Electric's transmission function. Limited pass through of such uncontrollable costs will provide better incentives, facilitate the recommended increase in the EARP's commitment period, and enhance the EARP's "staying power." The target rate of return and associated sharing bands might also be adjusted automatically if interest rates change substantially during the commitment period.

Fourth, issues that have caused disputes in the past should be addressed explicitly for the future. Relevant issues include the manner in which up-front customer credits and rate reductions are calculated and implemented, the details of monitoring and review provisions, applicable regulatory accounting standards, treatment of taxes, and the details of earnings sharing calculations.

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[84] *Second EARP Agreement*, p. 16.

Fifth, the likelihood or magnitude of disputes might be reduced by providing incentives to avoid the disputes in the first place. Interest charges on disputed components of sharing credits might be useful in this regard. In particular, the undisputed amounts of sharing credits could be passed on to customers immediately, while the disputed portions could be carried with interest. If the disputed amounts are resolved in the intervenors' favor, the Company would need to add interest to the disputed amounts, thereby increasing customer credits. If disputed amounts are resolved in the Company's favor, the interest on the disputed amounts would be an offset to customer credits. Such an arrangement could serve to discourage all parties from initiating disputes that they are unlikely to win. It could also encourage parties to resolve their remaining disputes quickly in order to limit interest charges.

Finally, to the extent that the modification and continuation of the EARP is in part based on a review of Union Electric's cost of service, such a review should specifically take into consideration the full *range* of parties' positions regarding the Company's likely current and future cost of service. For example, if the Company's current average cost of service is below current rates but is expected to increase during the EARP commitment period (*e.g.*, due to the need for new capacity investments), up-front customer credits may be more appropriate than permanent rate reductions. This is because a permanent rate reduction would not appropriately reflect the fact that the average cost of service is expected to increase over the course of the next commitment period. A cost-of-service review should also explicitly consider that: (1) UE's earnings are more uncertain under the EARP than under COSR (due to the rate freeze); and (2) the EARP dampens and limits up-side earnings potential while exposing UE fully to downside earnings risk. These facts imply that a target rate of return above the allowed return which would likely prevail under COS regulation merits serious consideration.

VII. CONCLUSIONS

Incentive regulation has become the most common form of regulation in the telecommunications industry and enjoys increasing popularity in the electric utility industry. There is broad consensus that well-designed incentive regulation is superior to traditional cost-of-service regulation. Regulatory commissions with extensive experience under incentive regulation stress its many benefits and advantages.

A preliminary evaluation shows that the EARP is a simple but effective form of incentive regulation. The EARP settlements have benefitted Union Electric's customers significantly through permanent rate reductions, up-front customer credits, and ongoing sharing credits. These EARP-related payments and rate reductions have combined to deliver more than $400 million in benefits to customers (not including benefits that customers received from Ameren's merger-related concessions) relative to the retail rates that were in effect prior to the EARP. Furthermore, these benefits have been delivered to customers more expeditiously than under traditional cost-of-service regulation.

It is difficult to calculate precisely the benefits that EARP has delivered relative to traditional cost-of-service regulation. However, it is clear that Union Electric's current cost of service may be substantially lower than it would have been had the Company been operating under cost-of-service regulation in recent years. This is because the EARP has provided Union Electric with stronger incentives to improve performance.

Union Electric's customers paid 4.8 percent less for electric power in 1999 than they paid in 1994, the year before the EARP was first implemented. (During the same time period, average consumer prices increased 12.4 percent.) Furthermore, all of UE's customer classes enjoyed greater reductions in electricity rates than customers of other utilities in the region. This comparison suggests that, under the EARP, annual expenditures by UE's customers may have already declined between $50 million to $100 million *more* than they would have had UE achieved only the average rate reduction of other Midwest utilities.

The analysis of Union Electric's EARP shows that customers pay less for electric power today than they paid prior to the implementation of the EARP, and enjoyed greater reduction in average electricity costs than customer of other utilities in the Midwest. These facts suggest that the EARP may well have served to deliver more benefits to customers than they would have received under traditional cost-of-service regulation. The continuation of the EARP, therefore, merits serious consideration. A step backward to cost-of-service ratemaking—or a resetting of UE's retail rates based on overly aggressive cost-of-service standards—would undermine the superior incentives that have motivated the Company to improve performance and deliver substantial benefits to customers since 1995.

As a possible new EARP settlement is negotiated, some potential enhancements to the current incentive regulation plan warrant careful consideration. In particular, the commitment period might be extended to four or five years. The sharing bands might be widened to allow more up-side rewards. Various pass-through provisions for uncontrollable costs might be added to increase the EARP's "staying power." Issues that have caused disputes in the past might also be addressed explicitly for the future, to reduce the likelihood or magnitude of disputes. In addition, a target rate of return above the return that would be allowed under cost-of-service regulation is warranted.

In summary, Union Electric and its customers alike have benefitted from the EARP over the past five years. Specific recognition that such a win-win situation can be achieved through incentive regulation is key to the successful negotiation and implementation of future alternative rate plans.

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