Chapter 8: Utility Regulation

The challenges and opportunities described in earlier chapters place increasing burdens on electricity system regulators. Issues specific to transmission were discussed in Chapter 4; the discussion in this chapter focuses on utility regulation in general terms, with particular attention on the determination of retail rates and treatment of investments. While various reforms of public utility regulation have long been debated, the impending changes will escalate regulatory policy design to higher prominence.

The chapter starts with an introduction to the primary objectives and current practices that guide setting electric utility rates. Although all forms of utility oversight generally reflect a common set of objectives, the details vary for different types of utilities. Section 8.1 gives an introduction to some of the most important distinctions and provides background for the findings and recommendations that follow.

Section 8.2 discusses emerging challenges for regulatory policy, beginning with the changing nature of utility investments. Many of the grid investments described in this report present greater risk than has been common over the past several decades. Next, we discuss customer incentives in the context of traditional rate structures. Recovering a substantial portion of distribution and transmission network costs through volumetric kilowatt-hour-based rates distorts both utility and customer incentives and over time may create implicit cross-subsidies across subsets of customers. Section 8.2 also discusses the stress that rising rates can put on regulatory processes, and the potential tension between a regulated franchise monopoly mind-set and distribution system innovation.

Section 8.3 assesses tools that might improve regulation of the U.S. electric power system in the context of the challenges outlined in the first two sections. These inform the conclusions and recommendations summarized in Section 8.4. We first find that consistent cost and performance metrics would allow for better comparisons of utility performance over time, and recommend that regulators collaborate to develop and publish such metrics, and that those with utility oversight authority ultimately tie utility outcomes to their performance on those metrics. Second, we find that new mechanisms for risk allocation and compensation are needed to balance incentives for risky investment with investment cost discipline, and we encourage continued experimentation and regulatory innovation in this direction. Finally, we find that alternatives to volumetric charges are needed to mitigate distortions common to most utility rate structures, and we recommend that fixed transmission and distribution network charges be recovered largely through customer-level fixed charges.

The U.S. electric power industry must invest significant amounts of capital over the coming decades to replace aging assets and expand the network to meet incremental load growth. That investment easily could double if utilities deploy new transmission and distribution technologies to improve system operation; enhance service quality; and accommodate new types of generation, load, and demand response.[1] To deliver on these promises in the most efficient and cost-effective manner, the regulatory systems and policies that oversee the U.S. grid also must be modernized.

8.1 REGULATORY OBJECTIVES AND PROCESSES

As described in Chapter 1, the organization of electricity systems in the U.S. varies widely. Until the 1990s, the industry was dominated by vertically integrated, investor-owned utilities (IOUs) that provided generation, transmission, and distribution services under rates that state public utility commissions regulated. In the late 1990s, independent transmission system operators (ISOs) were established in much of the nation. A number of states in ISO regions restructured their electric utilities by separating generation from transmission and distribution, and some states enabled competitive retail service, particularly for larger commercial and industrial customers. Generators in ISO regions sell into competitive wholesale markets for energy that is managed by the ISO, and distribution utilities and retailers purchase energy from those markets.

Some of the larger government-owned systems were and are vertically integrated, but most government and cooperatively owned systems are smaller utilities that purchase most or all their energy and transmission services from vertically integrated firms or independent power producers. They provide only distribution services to customers in their jurisdictions. The considerable heterogeneity in ownership, organizational, market, and regulatory forms limit generalizations across U.S. electricity systems, but some commonalities exist in core aspects of price determination.

First, distribution services are universally treated as a natural monopoly. Even in areas that have restructured their electricity markets, delivery of electricity from the high-voltage transmission network to end-use customers generally is assigned as an exclusive franchise to a government-owned or cooperative enterprise or to an IOU subject to some form of price regulation. In this chapter, we will refer to all such entities as "distribution utilities," recognizing they may be parts of vertically integrated organizations. Depending on the jurisdiction, generation and transmission assets—including transmission lines, the hardware and software in control centers, and various other sorts of equipment—also may be owned by entities of all these types.

Second, the prices for franchised monopoly services generally are determined administratively. State public utility commissions regulate the prices IOUs charge through proceedings known as "rate cases." City councils or independent boards oversee government-owned utilities. Customer-owned cooperatives are governed through committees or boards comprised of their members. The principles that govern rate determination are broadly similar across each of these organizational forms. When we refer to "regulators" in this chapter, we generally include entities responsible for supervising publicly and cooperatively owned utilities. Regulators universally determine the allowed cost recovery for distribution services; the cost of generation or wholesale power purchases and transmission is passed through according to rules that vary across regimes.

The principles that govern rate determination are broadly similar across each of these organizational forms.

Third, utility oversight generally reflects a common set of objectives:

- **Operational Efficiency:** Utilities should deliver the quantity of electricity that consumers wish to purchase at the lowest reasonable cost while providing acceptable reliability and other aspects of performance.

- **Dynamic Efficiency:** Utilities should make efficient investments in innovation so that they are able to meet future demands at the lowest reasonable cost.

- **Consumption Efficiency:** Customers should bear the incremental cost that their decisions impose and be given appropriate incentives to consume electricity only when its value to them is at least as great as the incremental cost of producing and delivering it. Prices should be set at the lowest level consistent with system cost recovery and investment incentives, with "cost" understood to include a fair rate of return on capital to investors or compensation for public capital for non-IOUs.

- **Other Policy Objectives:** Where utilities are expected to support other policy goals, they should do so in a cost-effective, minimally distortive manner. Regulators frequently establish distributional goals, such as requiring firms to design rates such that customers who are thought to be better able to pay bear a larger share of network (non-energy) or other regulated costs. Other goals may include enhanced energy efficiency and accommodation of renewable generation, distributed generation, or electric vehicles.

One of the greatest challenges facing regulators attempting to implement these objectives is asymmetric information: while a utility's demand characteristics and opportunities for cost reduction and investment may be fundamentally uncertain, managers of the utility typically have better information on these than does the regulator. As a general matter, this makes it impossible to simultaneously ensure exact cost recovery and provide optimal incentives for cost minimization.[2]

Two extreme theoretical regimes illustrate this problem. Pure cost-of-service regimes set utility revenues at all times exactly equal to observed utility costs, including a normal return on investment in the rate base. These schemes ensure full cost recovery because the regulator can generally measure actual costs precisely. But they provide no incentives to managers to exert effort to minimize those costs. In contrast, high-powered, incentive-based regimes decouple a utility's revenue from its actual costs. In a textbook price cap regime, for instance, prices are set once and remain fixed over time. This provides strong incentives for cost reduction because a dollar of cost savings translates into a dollar of profit. But revenues may greatly exceed costs or be far below them for any given utility or at any point in time.

One of the greatest challenges facing regulators attempting to implement these objectives is asymmetric information.

While actual regulatory practices depart from these theoretical extremes in significant ways, processes based broadly on cost-of-service regulation determine most U.S. retail electricity rates.[i] The mechanics of this regulatory process divide into two broad tasks:

- determining the utility's total cost—including a fair rate of return on prudent capital investments—which forms the basis of a total "revenue requirement"; and

- setting rates by allocating a share of required revenue to each customer class and determining the structure of rates to recover that revenue.

These processes play an important role in determining utility and customer incentives.[3]

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[i] Municipal, cooperative, and other non-IOU systems typically determine rates through different processes, but they lead to similar outcomes as cost-of-service regulation and involve similar efficiency problems.[4]

One important way the practice of cost-of-service regulation differs from the theoretical extreme characterization is that only the costs that regulators deem prudent are recoverable through the ratemaking process. This oversight process is particularly important for capital investments. Generation investments by IOUs outside competitive wholesale market areas and distribution system investments for all IOUs are subject to state commission review and rate regulation. Similar reviews apply to capital investments by publicly and cooperatively owned utilities. As discussed in Chapter 4, regulators of various sorts must give their approval before entities can build new transmission lines, and state commissions and the Federal Energy Regulatory Commission regulate the returns to rate-based transmission investments by IOUs.

Experiential learning is important for the prudency review process: over time, regulators develop familiarity with the types and levels of investments required to provide acceptable service for a given utility system and set of technologies. While utilities and regulators sometimes may disagree—for example, because of different views of the optimal level of reliability—most traditional distribution system investments have been relatively low risk, and reviews generally have been routine. Generation and transmission projects typically involve more significant outlays and, accordingly, receive detailed project-specific reviews.

We refer to network costs—the capital and operating costs of the distribution and transmission network—as "fixed costs" because they are largely unaffected by short-run changes in kWh energy consumption.

We refer to network costs—the capital and operating costs of the distribution and transmission network—as "fixed costs" because they are largely unaffected by short-run changes in kWh energy consumption. These costs are also relatively stable between rate reviews. In contrast, energy costs—reflecting either fuel costs for vertically integrated utilities or wholesale power acquisition costs for distribution utilities in restructured markets—vary with electricity consumption and change with fuel prices, among other factors. Fluctuations in energy costs generally flow through to rates via frequently changed volumetric energy charges—that is, charges applied to each kWh consumed—often implemented by automatic adjustment formulas indexed to costs.[ii] In some jurisdictions, a portion of distribution service rates also may be subject to an automatic adjustment between rate cases.

Once the required revenue for cost reimbursement has been determined, the regulator must decide how to set rates to recover those costs. To determine customer charges for distribution, network costs at the distribution level typically are first allocated to customer classes based on such factors as connection voltage and the class's estimated contribution to the local peak demand. Rates are computed to match the total cost allocated to each customer class to expected revenue, based on historic consumption levels and usage patterns for that class. All customers face distribution rates that are at least partially volumetric. For large customers, volumetric distribution charges tend to be low, and most of the allocated costs are recovered through fixed monthly charges, typically based on that customer's actual peak demand level during some prior base period or its contracted demand for some future period. In contrast, distribution and transmission system costs are recovered from small commercial and

[ii] In competitive retail markets, the retailer determines the contractual energy price, which is combined with the regulated transmission and distribution charges into a single customer bill.

residential customers almost entirely through volumetric delivery rates ($/kWh), with very low fixed monthly customer charges in virtually all jurisdictions.

Revenue adequacy for the distribution utility is met by matching the expected aggregate revenues across all customers, given rates and expected levels of consumption, to the revenue required to match total allowed system costs. In another departure from the theoretical model of pure cost-of-service regulation, those rates generally are then fixed until the next regulatory review, apart from the impact of any automatic adjustment formulas.

The detail of charges customers see on their bills varies tremendously across jurisdictions. Many customers receive bills that aggregate energy, transmission, and distribution charges into a (generally small) fixed monthly customer charge and usage charges based on kWh consumption, often with two or more steps that increase the kWh charge as monthly consumption rises above threshold levels (a structure known as "increasing block pricing"). In some jurisdictions, notably those with retail competition, bills may be "unbundled," with separate charges detailed for energy, transmission, and distribution, each of which may change across usage "steps." As noted in Chapter 7, the delivered electricity rates are constant within a billing cycle for most residential and small commercial customers. Larger commercial and industrial customers are more likely to face rates that vary with time of day and day of the week, and for some, with system conditions.

Between 1990 and 2010, the annual average increase in the Consumer Price Index was only 2.6%, and average retail electricity rates increased by only 2.1% per year on average.[5] A variety of factors contributed to this performance, among them efficiency gains in generation as a consequence of competitive wholesale electricity markets and, in networks, because of incentive-based regulation.[6] In this low-inflation environment, utility ratemaking overall has functioned relatively smoothly, unlike some earlier periods when costs were rising more quickly.[7] But changes in the economic environment and the demands placed on utilities are likely to increasingly strain the existing regulatory system during the coming decades, increasing the value of regulatory adaptation and innovation.

8.2 GROWING CHALLENGES FOR REGULATORY POLICY

Several factors will combine to increase the likely stress on existing regulatory practices in the coming decades. Many will arise from the significant investments in new technologies that systems may need to make to improve system operation and accommodate new demands on electricity networks, as described in previous chapters. Traditional regulatory approaches have difficulty assuring that incentives and compensation for such investments lead to cost-effective decisions. Paying for increased network investment, combined with higher power costs that may arise from policy mandates, such as renewable portfolio standards, is likely to require electricity rate increases. Rising rate levels challenge most regulatory systems. Prevailing rate structures may compound the difficulty of managing increases, both by limiting demand engagement, as discussed in Chapter 7, and by giving some customers the incentive and ability to shift part of their share of network costs onto other customers, as we describe below. Finally, innovation in customer-facing activities may not be well-matched to the focus, skill set, and incentives of traditional utilities or their regulators.

Paying for increased network investment, combined with higher power costs that may arise from policy mandates, such as renewable portfolio standards, is likely to require electricity rate increases.

The Nature of Investments Is Changing

Meeting the future expectations for transmission and distribution systems in a cost-effective manner will require utilities to evaluate and potentially adopt technologies that significantly depart from traditional grid investments. Among the required new capabilities are automated sensing and control (Chapters 2 and 6), development of more responsive demand (Chapter 7), and accommodation of variable energy resources, distributed generation, and electric vehicles (Chapters 3, 4, and 5). The total cost of integrating large amounts of variable energy resources and distributed generation in particular will depend on the degree of automation and active management of the transmission and distribution networks, and there are no system-scale deployments in existence to serve as models.[8] Electric vehicles may require distribution network component upgrades, although their timing and magnitude depend critically on the penetration and geographic distribution of electric vehicles within the distribution system and how charging is metered, controlled, and priced.

Ideally, utilities would invest in risky new technologies if the expected returns when the technology is successful are at least sufficient to compensate for possible losses if the technology fails. In theory, cost-of-service regulation encourages utility capital investment by assuring utilities a “fair” rate of return on their investment. This suggests that regulated utilities might be eager to undertake investments of all sorts, risky or not. In practice, however, the uncertainty associated with new technologies and risk aversion on the part of regulators and utilities may discourage even efficient investments.

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Utilities considering significant capital investments generally seek to reduce the regulatory uncertainty through *ex ante* prudency reviews. But for many new transmission and distribution technologies considered in this report, neither the utility nor the regulator may have much, if any, experience assessing the technology.[9] Forecasting the level of capital expenditures, net change in operating costs, and system benefits of emerging technologies can be difficult in such situations. Without good data, regulators may have a hard time deciding whether to approve investment proposals and how to hold utilities accountable for their best estimates of costs and benefits.

For example, investments in new distribution technologies, such as those necessary to efficiently and reliably integrate distributed generation or effectively use the wealth of information provided by advanced metering infrastructure (AMI), may be subject to uncertainty about not only the *level* of costs and benefits but also about their timing and achievability. To be most effective, these investments may require coordination across different utility business units and the integration of legacy data communications and information management systems. Utilities may have limited experience with these technologies and have to work closely with equipment vendors that may have little experience with electric power distribution systems. Complicating calculations further, many new technologies have benefit streams that potentially will extend many years after costs have been incurred and are partially a function of future technology innovation and deployment decisions. As a result, modernization investments may not be easily justified by predictable short-term improvements in reliability or incremental improvements in operations or operating costs. Extrapolation or meta-analyses of pilot results may help to narrow the range of likely outcomes, but considerable uncertainty for system deployments may remain.

In addition, state regulators have sometimes approved investments in *ex ante* prudency reviews only to later deny a utility's full cost recovery. For example, a recent Colorado decision denied Xcel Energy cost recovery for certain smart grid investments in Boulder, Colorado, after the regulator had approved the investment proposals, because the costs were substantially in excess of those initially anticipated.[10] While such actions may be needed to provide strong incentives for managing costs, aversion to such risks may make utilities excessively cautious in proposing investments with highly uncertain costs. The political process may create similar conservatism among regulators. Regulators are unlikely to face censure for failing to encourage novel investments that might have yielded new benefits or moderated rate increases but that customers never learn about. In contrast, regulators may face considerable criticism for approving rate increases for technologies that fail to meet expectations or, worse, involve well-publicized problems.

Another challenge posed by the changing nature of new investments is that some significant benefits of grid modernization may not be fully internalized by a single utility or its customers.[11] For instance, if a particular distribution utility increases the responsiveness of its customers' demand or the efficiency of their energy use and thereby reduces regional generation costs, some of the benefits may accrue to customers in the same region who are not served by that distribution utility. Similarly, early adopters of new technologies and systems may end up incurring costs that are avoided in later adoptions through learning spillovers from early experiences.

These considerations may bias investment toward the mature technologies and assets that are familiar to utilities and regulators.[12] Such conservatism may dramatically retard the adoption of technologies to modernize the grid, even when deployment of those technologies is likely to be the most cost-effective path to accommodate the policy goals impressed on the system.

FINDING

Excessively conservative decision-making by utilities and their regulators may dramatically slow cost-effective investments to modernize the grid.

Traditional Rate Structures Distort Incentives

The traditional structure of electricity rates in the U.S. may increasingly impede efficiency objectives over the coming decades. As discussed in Chapter 7, many consumers face rates that often deviate substantially from the incremental costs their consumption decisions impose on the electric power system. Rates charged to most residential and small commercial customers vary little or not at all over the hour or the day, leading to excessive consumption during system peaks and inefficiently discouraging off-peak consumption. Real-time prices that reflect current system costs are rare, even among larger customers.

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If delivered prices are below incremental costs, as may occur during peak demand periods for customers facing time-invariant rates based on average costs, customers will use inefficiently high quantities of electricity at high-cost times. This can increase energy acquisition costs and require additional investments in both generation and grid capacity to meet peak demand, reducing capacity utilization and increasing average costs (and therefore average rates) above efficient levels.

But prices that are higher than incremental costs can be equally distortionary. By recovering a substantial portion of distribution and transmission costs through volumetric charges, the dominant U.S. rate practices give utilities incentives to increase their sales and discourage energy conservation and distributed generation because they reduce sales. Volumetric charges are especially problematic when energy consumption falls. If network costs are largely unchanged by consumption changes, as we would expect, reduced consumption decreases revenue by much more than it decreases costs, creating a revenue adequacy problem for the utility and perhaps setting off a spiral of rising rates. While these problems are not new, they are likely to grow over the coming years as public policies increasingly favor energy efficiency and distributed generation.

On the customer side, when the average delivered price of electricity is higher than the incremental cost of providing that energy, there is an incentive for "disintermediation"—reducing purchases of power from the regulated utility. This situation with respect to wholesale generation costs led many large industrial and commercial customers in states with high regulated rates in the 1990s to press for restructuring and retail competition so they could shift their purchases to lower-cost wholesale providers or self-generate.[13] The coming decades could see a similar phenomenon among smaller commercial and residential customers. High per kWh distribution rates create an implicit subsidy to self-generation of all sorts—solar, wind, or diesel. Renewable generation may receive additional direct subsidies. This could lead to inefficiently high use of self-generation, and there is no reason to assume it will all be "clean." Forty-six states and the District of Columbia use net-metering systems that compensate distributed generation through avoidance of volumetric retail rates[14] even though network-related costs to serve a customer are not likely to fall with their use of distributed generation. This practice in effect adds an extra subsidy to distributed generation not given to grid-scale generators. Inclining block pricing used in some jurisdictions—rates that increase as monthly consumption rises—can exacerbate the problem.[iii] The distortions caused by these implicit subsidies rise with the penetration of distributed generation and with energy conservation more generally. Consider, for example, proposed "zero net energy" buildings: if network costs continue to be recovered on a per-kWh basis, these customers could in theory receive all the benefits of being connected to the grid, drawing and injecting power on demand, while paying little or nothing toward the cost of the system or the option to use the network.

High per kWh distribution rates create an implicit subsidy to self-generation of all sorts.

[iii] Some have suggested that distortions induced by volumetric charges to recover fixed costs and the potentially greater distortions caused by increasing block pricing may be justified by the presence of imperfections in the market for electricity—for example, because cost-based prices do not reflect the incremental social cost of electricity consumption, particularly from "dirty" sources, or because consumers need higher prices to overcome their inertia and make desirable efficiency investments.[15]

While the economic theory of "second-best pricing" recognizes that marginal cost prices may not be optimal in the presence of market and decision-making imperfections, there is no theorem suggesting that one potential distortion merits another. Such decisions must be based on careful analysis and situation-specific modeling and measurement to ensure improvements to welfare, with a healthy skepticism toward the benefits of adding layers of distortions.[16]

FINDING

Net metering policies provide an implicit subsidy to all forms of distributed generation that is not given to grid-scale generators.

Requiring middle- or lower-income customers to subsidize wealthier households' investments in energy reduction, as traditional rate structures do, would seem difficult to rationalize.

Moreover, distributed generation and efficiency programs do not appreciably reduce transmission or distribution system costs—and may even increase them as investments are needed to accommodate more than modest increases in renewable generation. Who pays for the revenue lost because of such programs under current rate structures? If all customers reduce consumption proportionally and fixed system costs are unchanged, in the long run volumetric rates must rise to exactly offset the fall in consumption. The per kWh rate will rise, and customers' total bills after rates adjust will be smaller only by the energy cost differential. If consumers do not understand this when investing in self-generation or efficiency, consistently smaller returns than anticipated from their investments may create substantial dissonance. If only some customers reduce their net energy purchases through self-generation or efficiency investments, distribution system costs will be shifted onto those who do not. This raises questions of both horizontal inequity—treating otherwise similar consumers differently—and vertical inequity—penalizing lower-income consumers, who may be disproportionately represented among those less able to finance investments to reduce net electricity consumption. Requiring middle- or lower-income customers to subsidize wealthier households' investments in energy reduction, as traditional rate structures do, would seem difficult to rationalize on equity or political grounds.

Rising Rates Stress the Regulatory Process

Rising costs often test regulatory systems. Utility customers, particularly at the residential level, are sensitive to higher nominal bills, as noted in academic work in the mid-1970s and reinforced by the recent backlash against higher monthly bills coincident with AMI rollouts in Texas and California.[17] Customer resistance to higher rates may pressure regulators to avoid increases, even when they are needed to compensate utilities for efficient levels of operating and investment costs.[18] This was not a significant problem over the past two decades, when nominal rate increases were modest and average real prices fell across most electricity markets. But the increased cost of new transmission and distribution investments, combined with possible increases in average generation costs due to policy mandates, such as renewable portfolio standards or more stringent environmental regulations, may lead to significant increases in the delivered cost of electricity. The Electric Power Research Institute (EPRI) estimates the average *incremental* increase in monthly electricity bills required to finance smart grid transmission and distribution investments will be in the range of 8%–12% for residential and commercial customers when amortized over a 10-year period.[19] In the same report, EPRI also notes that digital-based technologies depreciate more quickly than do historic distribution system assets, so maintaining the smart grid system may require higher ongoing investment levels than in recent decades. These expenditures are in addition to rate increases needed to compensate for higher generation costs and investment in transmission and distribution to meet load growth, replace end-of-life assets, and integrate renewables.

Without policy adaptation, the system risks destabilization: If utilities make investments in an environment of substantial uncertain cost recovery, their cost of capital may rise, exacerbating cost-recovery challenges. But if utilities defer investments, they may be unable to meet the conflicting demands of customers, regulators, and policy makers. Finding ways to increase the efficiency of the power system, and therefore reduce costs, will be critical to offsetting some of this pressure. Improved transparency and active customer education and engagement also may help mitigate some customer resistance to necessary rate increases. Communicating the rate implications of new investments and programs poses challenges, however. For example, investments that reduce costs from what they would otherwise have been but still involve rate increases may create substantial dissonance if customers anticipate rate *decreases* that fail to materialize.

The volumetric rate structure for residential and small commercial customers may further reinforce a perverse dynamic over time.

The volumetric rate structure for residential and small commercial customers may further reinforce a perverse dynamic over time. Reduced consumption threatens the ability of a distribution utility to recover its predominantly fixed costs. This, in turn, necessitates rate increases. Higher prices offset the savings customers may have expected from their efficiency or conservation decisions and may provide an even larger incentive for future reductions in customer demand, ratcheting prices up still further. This cycle of rising distribution rates further incites customer dissatisfaction and may distort consumption decisions. While some have argued that increasing efficiency and distributed generation are benefits of volumetric rates, inducing customer-side investments on the basis of illusory bill savings may create considerable political backlash over time, particularly if consumers focus on nominal rates.[20]

A "Franchise Monopoly" Mind-set May Discourage Innovation

While there is broad consensus that physical distribution networks comprise a natural monopoly, there is little agreement that other functions provided by distribution system operators should be assigned exclusively, or at all, to a legal monopolist. Indeed, a primary motivation for electricity restructuring across a number of countries and in many U.S. states was the perceived potential for competition in both wholesale generation and retailing markets to reduce costs, and ultimately electricity rates, from what they would otherwise have been.[21] Under retail competition, consumers receive regulated delivery services from their distribution utility and are free to purchase energy and other related services from competitive electricity retailers.

As Chapter 1 noted, while more than half of U.S. states allow retail competition for large industrial or commercial customers, few today have competitive electricity retail markets at the residential level. In part, this reflects the retrenchment from electricity restructuring efforts that followed the California electricity crisis of 2000–2001.[22] The form of retail competition also varies widely. At the extreme is the fully separated EU model, implemented through its Electricity Directive, in which the distribution utility is allowed to sell only distribution network services; energy and other services must be purchased from other enterprises. This is essentially the approach used in Texas, but retail competition associated with full unbundling constitutes the exception and not the rule in the U.S. Without retail competition, innovation in retail electricity services depends on incumbent monopoly distribution companies. But rate regulation may impede the efficient development and introduction of new services. Innovation involves risk, and as we have noted, regulated firms have little to gain from voluntarily assuming risks: if things go well, the benefits go mainly to customers; if things go badly, the pain is borne mainly by managers and shareholders.

In the presence of new and emerging technologies, competitive entry into retailing may, for example, stimulate the development of new energy management systems, provide investment funds for deployment of new customer premises technologies, leverage retailing efficiencies by facilitating operations across many distribution systems, and provide a better match for the expertise and talent required to be successful in services that rely heavily on information technology and customer engagement activities. Separating retailing from distribution services also could resolve debates over who owns and pays for customer premises demand management technologies and whether the cost of those investments should be "socialized" across all customers through inclusion in a utility's rate base, by shifting those responsibilities onto competing retailers.[iv]

8.3 HOW SHOULD POLICY RESPOND?

Challenges to regulatory policy are gaining increased prominence with the quickening pace of innovation in distribution system technologies, penetration of distributed generation and electric vehicles, and policy emphasis on energy efficiency and alternatives to conventional generation sources. Addressing these challenges in a cost-effective manner is likely to require more widespread use of new regulatory tools, significant adaptation of regulatory processes, and continued experimentation. This section discusses a set of the most promising regulatory responses.

Regulators around the world have shifted regulation of traditional "public utility" sectors ... from cost-of-service to incentive-based schemes designed to motivate utilities to reduce operational costs without sacrificing reliability or quality of service.

Enhance Performance-Based Incentive Regulation

Regulators around the world have shifted regulation of traditional "public utility" sectors—for example, local wireline telecommunications, natural gas distribution, and distribution of electricity—from cost-of-service to incentive-based schemes designed to motivate utilities to reduce operational costs without sacrificing reliability or quality of service. Inherent in their design is the possibility that utility revenues may exceed or fall short of costs for significant periods of time. The potential savings from these approaches may be considerable. For example, electricity distribution companies in England and Wales that were subject to price cap regulation dramatically reduced operating costs, reflecting the combined benefit of incentive regulation and privatization.[23] While the use of incentive-based regulation in U.S. electric utilities has been more limited, empirical analysis of restructured U.S. electricity markets reveals improvements in generator efficiency associated with some forms of regulatory incentives and with market-based competition among generators instead of cost-of-service regulated rates.[24]

[iv] Regulators cannot ignore, however, that the main business of retailers is to sell electricity. When energy efficiency and savings becomes a regulatory priority, energy service companies, whose only purpose is to reduce consumption or to shift it to low cost periods of time, are best suited for this job.

Internationally, the most common form of incentive-based regulation sets a price or total revenue cap for delivery service that is fixed over a given time period, typically three to five years, and is thus independent of actual costs. During this period, firms are allowed to charge prices (or earn total revenues) that increase with an index of the general price level, plus or minus a fixed percentage adjustment factor set by the regulator. The adjustment factor is generally set to equate the discounted expected values of costs and revenues over the time period considered, taking into account expected productivity gains. This approach, pioneered in England and Wales, generally is known as RPI – X regulation, where RPI refers to the Retail Price Index (like the U.S. Consumer Price Index), and X is the adjustment factor determined by the regulator. Under this system, regulated firms can increase profits by reducing costs relative to the index.

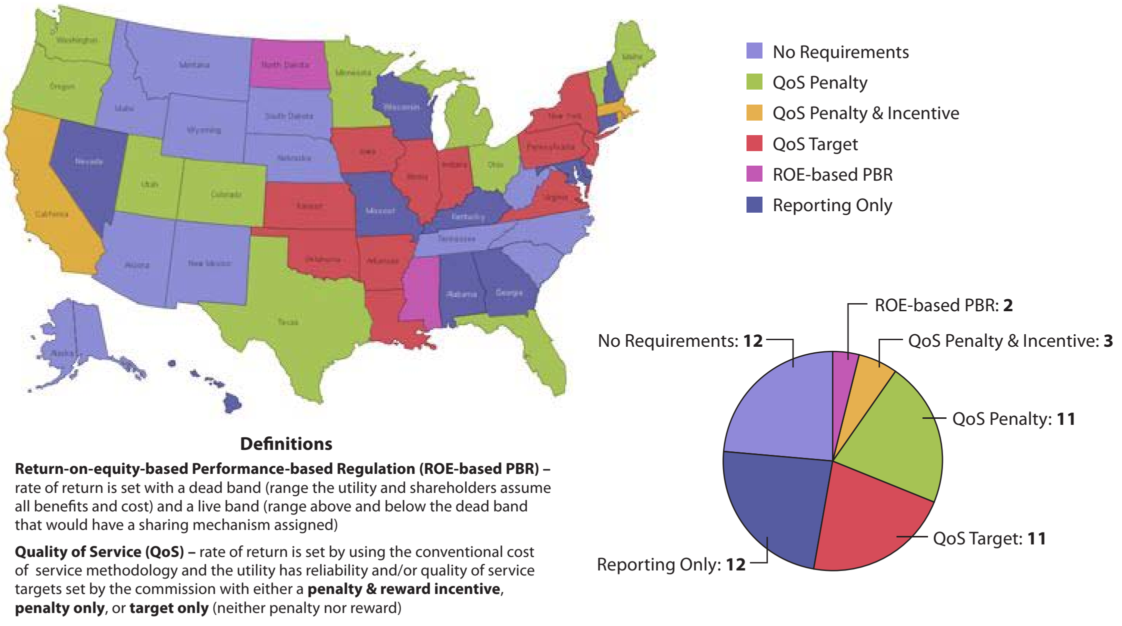
Since one way of reducing costs may be to reduce spending on reliability or service quality, implementations in England, Australia, and other countries in Europe and Latin America have evolved to include performance metrics and assign penalties or rewards depending on whether utilities meet these predetermined targets. During the 1990s, regulators in many U.S. states began experimenting with a variety of incentive-based regulations. These included a broad range of changes, from relatively short-term price caps, to rate freezes, rate case moratoria, and earnings sharing plans. In 2001, at least 28 distribution utilities in 16 states were regulated under such mechanisms.[25] Subsequently a number have returned to more traditional cost-of-service-based ratemaking supplemented by reliability or quality-of-service targets with penalties and rewards as performance incentives.

As of 2005, 16 states had a form of performance-based regulation that included explicit penalties or rewards based on performance in reliability and/or quality of service.

Figure 8.1 classifies U.S. states based on their adoption of performance-based regulatory systems involving quality of service. As of 2005, 16 states had a form of performance-based regulation that included explicit penalties or rewards based on performance in reliability and/or quality of service.[26] Of these, two states adjusted the allowed rate of return based on performance. An additional 23 states set service targets or required utilities to report performance but associated no financial consequences to those reports. Assessing the impact of performance-based regulation across U.S. distribution utilities is extremely difficult, in part because of this heterogeneity in standards, incentives, and performance reporting. One study finds programs that provide generating units incentives to meet certain heat rate and availability goals are associated with improvements in generating unit efficiency, suggesting at least some role for performance-based incentives.[27]

Jurisdictions that require electric utilities to report performance on various metrics have commonly used the results to provide incentives for efficient operations. While less high-powered than the price or revenue caps many European systems employ, performance-based incentives may yield some gains even at the level currently employed across many U.S. utilities. Expanding their use and formally tying performance to financial incentives can increase those gains, particularly as regulators and utilities are faced with assessment of new technologies. Candidates for measurement and reporting would include detailed information on the duration, incidence, and cause of outages; customer service indicators; power quality measurement; and performance on possible policy goals, such as integration of distributed generation and electric vehicles or demand response.

Figure 8.1 States with Performance-Based Cost-of-Service Regulation, 2005



Definitions

Return-on-equity-based Performance-based Regulation (ROE-based PBR) – rate of return is set with a dead band (range the utility and shareholders assume all benefits and cost) and a live band (range above and below the dead band that would have a sharing mechanism assigned)

Quality of Service (QoS) – rate of return is set by using the conventional cost of service methodology and the utility has reliability and/or quality of service targets set by the commission with either a **penalty & reward incentive**, **penalty only**, or **target only** (neither penalty nor reward)

Reporting Only – utility is required to report performance with no penalty, reward or target

Source: Davies Consulting, Inc., *State of Distribution Reliability Regulation in the United States* (Washington, DC: Edison Electric Institute, 2005), Table 4-1.

FINDING

Greater performance-based regulation can improve the efficiency of the distribution system and the quality of utility investments. Better and more comparable data on system costs and performance, including how well the system accommodates policy goals, are needed for its effective implementation.

The value of cost and performance data could be substantially enhanced by coordinating the definition and measurement of metrics across regulatory jurisdictions, expanding their use in regulation, and publishing data on observed performance. While heterogeneity across service territories may preclude simple formulaic comparisons across utilities, commonly publicized metrics could support incentives for improvement and facilitate the development of standards of service. Progress along these directions should be strongly encouraged.

Regulators in the European Union and elsewhere use two tools—benchmarking and reference network models (RNMs)—that can further enhance the value of incentive-based regulation. Benchmarking involves gathering and analyzing comparable cost and network data from a large number of potentially similar utilities.[28] Regulators outside the U.S. commonly benchmark operating costs and quality of service across different types of networks to determine efficient cost and performance levels for comparable utilities.[29] For prices set using RPI – X formulas, this exercise can help regulators understand the significant cost drivers external to the utility and thus choose a price or revenue cap and adjustment factor that satisfies expected cost-recovery goals. As might be expected, the most cost-efficient utilities do not always exhibit high levels of service quality.[30] By focusing both on service quality and costs, regulators can attempt to provide utilities with incentives to reduce operating cost while maintaining acceptable levels of service quality.

Gaps in publicly available, detailed, utility-specific data—particularly on performance—for a large number of U.S. distribution utilities currently make it difficult to use benchmarking methods.

Hindering benchmarking efforts are differences in the size and geographical dispersion of the customer base; terrain of the service area; design choices of underground or overhead lines; age and type of assets; amount and timing of specific investments; and accounting or depreciation practices across jurisdictions.[31] Although econometric models combined with detailed system data may help regulators to expand the set of firms deemed "comparable," it can be difficult to adjust for these and other differences, particularly for capital investments. Even in jurisdictions that employ price caps with RPI – X indices for operating costs, capital costs tend to be incorporated into price caps in a manner quite similar to cost-of-service reviews.[32] But by incorporating lessons from others' experiences, benchmarking may at least reduce the significant uncertainties associated with investments in some new technologies.

Gaps in publicly available, detailed, utility-specific data—particularly on performance—for a large number of U.S. distribution utilities currently make it difficult to use benchmarking methods. With distribution network modernization proceeding at different rates across the nation, data will need to be collected over a long period to inform comparisons of modernized distribution systems. The earlier and more intentional the data collection and analysis are, the more informative the results of benchmarking are likely to be.

A second tool used by distribution system regulators in a number of European countries is an engineering-based RNM. These models accept detailed data on the geographical terrain of an individual utility's distribution service area, its network design, and customers' position and load profiles to provide a customized reference or benchmark against which its realized operating and investment performance can be evaluated.[33] By incorporating technical and reliability constraints, distribution network configurations, and operation and management costs, RNMs permit simulation of investment and revenue requirements. RNMs thus can be used to assess capital and operating expenses not only in the design of new distribution systems but also in the expansion of existing systems. They also may be helpful in estimating costs of nontraditional investments for integrating distributed generation and accommodating electric vehicles, and they may improve our understanding of how these new network users affect reliability and quality of service.

A disadvantage of RNMs is that they are necessarily complex and difficult to understand for those not expert in planning distribution networks. An integrated assessment of the wide range of technologies under consideration is needed to build models that can accurately represent evolving distribution systems. However, once built and validated, an RNM can be shared across jurisdictions to provide regulators with both qualitative and quantitative insights into the impacts of potential system changes. The model can complement regulatory judgment in assessing the impact of new policies and informing the design of targeted experiments or pilot projects.[34]

Create New Cost-Recovery Paradigms

Addressing the increased uncertainty inherent in many new grid technologies will require regulators and utilities to consider new cost-recovery regimes. Traditional utility regulation has focused more on curbing monopoly power and avoiding excessive costs and less on encouraging innovation. This focus is becoming increasingly expensive, as technological change is rapid and the potential gains from innovation are great.

A core determinant of innovation incentives is the allocation of and compensation for investment risk. On the one hand, if investor-owned utilities do not expect to earn at least their cost of capital on new investments unless everything goes exactly as planned, they will avoid investments with any risk, and the promised benefits of new technologies will be realized too slowly or perhaps not at all. On the other hand, ensuring utilities full cost recovery regardless of the level of incurred costs or realized benefits would give them little reason to contain costs or carefully vet investment proposals. Consumers in the latter case might see significant innovation but could face substantially higher costs and excessive risks. The difficulty is finding a good middle ground between these extremes.

For non-investor-owned utilities, versions of this trade-off arise that involve rewards and penalties for utility managers and their supervisors depending on the outcomes of risky investments. Some have suggested to us that these utilities may be more willing to innovate because managers do not have to worry about shareholder reactions to bad outcomes. While some economic analyses suggest scope for substantial managerial discretion in publicly owned entities,[35] we are unaware of any definitive evidence on the empirical relation between utility governance structure and incentives for innovation.[v]

Addressing the increased uncertainty inherent in many new grid technologies will require regulators and utilities to consider new cost-recovery regimes.

Variants of traditional ratemaking approaches may partially address the challenges risky investments pose. Pilot projects have been funded by ratepayers to demonstrate both feasibility and assess costs through a small-scale deployment. Reversing the decline in utility R&D budgets noted in Chapter 1 to restore modest funding may help fund experimental deployments, which typically require collaboration between utilities and vendors; leveraging R&D budgets through more cross-utility R&D projects or industry organizations, such as EPRI, may enhance their impact. Regulators could reduce utilities' risks by conducting an *ex ante* prudency review as part of a forward-looking planning process—perhaps using RNMs or benchmarking—and authorizing investment expenditures up to a specific ceiling based on that review. This reduces risk when investments within a predefined range of those expenditures are then exempt from *ex post* reconsideration, or when cost recovery is conditioned on achieving specific predetermined functionalities. Some jurisdictions address short-run uncertainty in cost recovery through the use of trackers or balancing accounts. These mechanisms follow a specific

[v] One suggestive piece of evidence is that cooperatives have deployed AMI to almost 25% of their customers, and "political subdivisions" (public power districts, public utility districts, and the like) have deployed it to more than 20%. In contrast, only 6.6% of IOU customers have AMI, and penetration is even lower for municipal entities (3.6%) and federal and state utilities (0.7%).[36] Clearly these dramatic differences reflect more than governance. In particular, cooperatives and political subdivisions tend to have more geographically dispersed customers, which implies larger benefits from AMI communication capabilities. But the differences are so large that it is hard to believe that governance is not part of the story.

type of expenditure—for example, AMI deployment costs—over a specified period and increase rates or add a surcharge over a number of subsequent periods until the full cost has been recovered. Regulators also have authorized recovery of some risk-contingency funding at the beginning of an investment project or rewarded utilities with incentive payments above and beyond their investment costs for meeting or exceeding specified performance targets.

While approaches such as these may reduce utilities' perceived investment risk, they do not necessarily provide strong incentives to minimize costs. Cost-sharing or shared savings plans can contribute to that goal. For example, the California Public Utility Commission authorized a cost-sharing plan for San Diego Gas & Electric's AMI deployment that rewarded utility investors with a share of savings if investment costs fell below authorized levels, but required investors to bear a share of cost overruns. Programs that penalize utilities if they do not attain certain levels of forecast benefits from investments are another way regulators may attempt to strengthen incentives for cost-efficient investments.

FINDING

Innovative network technologies may require new regulatory approaches to encourage experimentation and efficient deployment, especially when their costs are uncertain and their benefits involve enhancing the performance of the transmission or distribution system rather than merely expanding its capacity.

Creative regulatory approaches may be particularly valuable by promoting investments in the most innovative technologies, where costs and benefits are most uncertain. Collaborations among regulators, utilities, and technology providers are likely to be important in this domain. Experimental policies in the United Kingdom and elsewhere may yield insights for state regulators and others who supervise distribution utilities. For example, the U.K. Office of Gas and Electricity Markets has proposed a set of new cost-recovery, stimulus, and competition programs to encourage investment in promising but uncertain new network technologies.[37] These programs are intended to reduce asymmetries between risk and reward for investments in new technologies, provide a source of financing, and employ potential competition to encourage experimentation and deployment.

The three main IOUs in California, in collaboration with the Lawrence Livermore National Laboratory, recently proposed a novel approach to encourage innovation in a joint filing to the California Public Utility Commission.[38] The California Energy Systems for the 21st Century Project requests a five-year $150 million commitment from ratepayers to fund R&D relating to four broad areas: cybersecurity, electric resource planning, system operations, and workforce preparedness. Specific selection of activities and oversight will be provided by a board of directors that includes representation from industry, government, and, potentially, public interests. The project emphasizes the development of planning tools and system integration, areas that are likely to be increasingly important for distribution systems. The regulatory response to this proposal as well as its potential implementation and ultimate output may provide a model for other jurisdictions.

The problem of providing appropriate incentives for investment in innovative distribution system technologies is difficult. But it is important now and will become more important in the decades ahead. State regulators and others who supervise distribution utilities should tackle it sooner rather than later. The diversity across U.S. jurisdictions in regulatory philosophies and approaches could be a source of strength, as long as regulators maintain transparency and exchange experiences to identify and emulate the most promising solutions.

Improve Rate Structures

Utility rate structures will assume increased importance going forward, particularly as potentially large investments in transmission and distribution systems cause rates to increase and threaten the current political equilibrium. As noted earlier in the chapter, transmission and distribution costs are largely independent of delivered energy in the short term, but the recovery of those costs from residential and small commercial customers generally is heavily dependent on energy sales. Whenever prices are out of line with costs, behavior is distorted and economic efficiency is reduced.[vi]

FINDING

Recovery of largely fixed network costs through volumetric ($/kWh) charges distorts the behavior of utilities, their customers, and investors in distributed generation—and may be politically unstable in an era of rising costs.

Reducing reliance on energy sales for transmission and distribution network cost recovery addresses these problems directly. Regulators can accomplish this by increasing fixed customer charges or demand charges (charges that depend on peak kW or capacity use, not energy use) and reducing or eliminating per kWh charges for network cost recovery.[vii] Not only does this approach remove the root cause of distortions while assuring recovery of approved costs, it also may be more politically sustainable over time than are volumetric charges.

In the past, recovering costs through volumetric charges for smaller customers may have been expedient: network charges were not a large fraction of the total electricity bill, and metering costs to compute appropriate demand charges were relatively high. Less costly alternatives used outside the U.S., such as limiters that prevent consumption levels above a contracted peak amount, had little appeal to U.S. regulators. As network charges now approach parity with energy costs for many customers, this structure demands closer attention. And as AMI diffuses, it becomes easier and less expensive to vary fixed charges across customers in ways that reflect their differential impacts on the need for network development.

AMI meters can record consumption that is coincident with system peaks or measure average consumption over a set of designated peak hours. These facilitate a transition to fixed monthly delivery charges that vary with either usage in local peak periods or another measure of impact on the need for network capacity. Because peak usage tends to be correlated with total usage across households, these charges will lead to "larger" customers generally paying a greater fraction of system costs than do "smaller" customers, as they do under volumetric pricing, but without

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[vi] In principle this problem also arises with regard to transmission costs in most areas, and both transmission and distribution charges should be addressed similarly. However, because transmission costs are considerably lower than distribution costs, the distortions caused by recovering fixed transmission costs via volumetric charges may be less severe.

[vii] An ideal approach would start with energy charges based on locational marginal prices at each distribution node and point in time, and use customer fixed charges to recover more of the remaining network costs. But current systems are far from measuring, let alone implementing that ideal.

substantial distortions to consumption and distributed generation investment decisions. Moving from volumetric to peak-demand-based cost recovery also largely eliminates any utility incentive to increase its sales. And fixed pricing may better match costs to revenues: given that distribution system capacity heavily depends on the local peak demand, demand charges better reflect the capacity costs each customer imposes on the system. Reduced demand at system peaks can lead to lower distribution costs over time by reducing the need to replace or add distribution capacity, which is not the case for reductions in energy usage during most periods.

Where regulators choose not to place primary reliance on demand or fixed customer charges,"decoupling" mechanisms can address some of the problems the volumetric rate structure creates. Decoupling mechanisms aim to separate utilities' revenues from their volumetric sales, improving recovery of fixed delivery costs between rate cases and thereby mitigating utilities' incentives to maintain or increase energy sales. If all distribution costs were recovered through fixed charges, a utility's revenue would be independent of its sales in each period—essentially perfect decoupling. The greater the share of distribution costs recovered through volumetric charges, the more need there may be for formal decoupling programs.

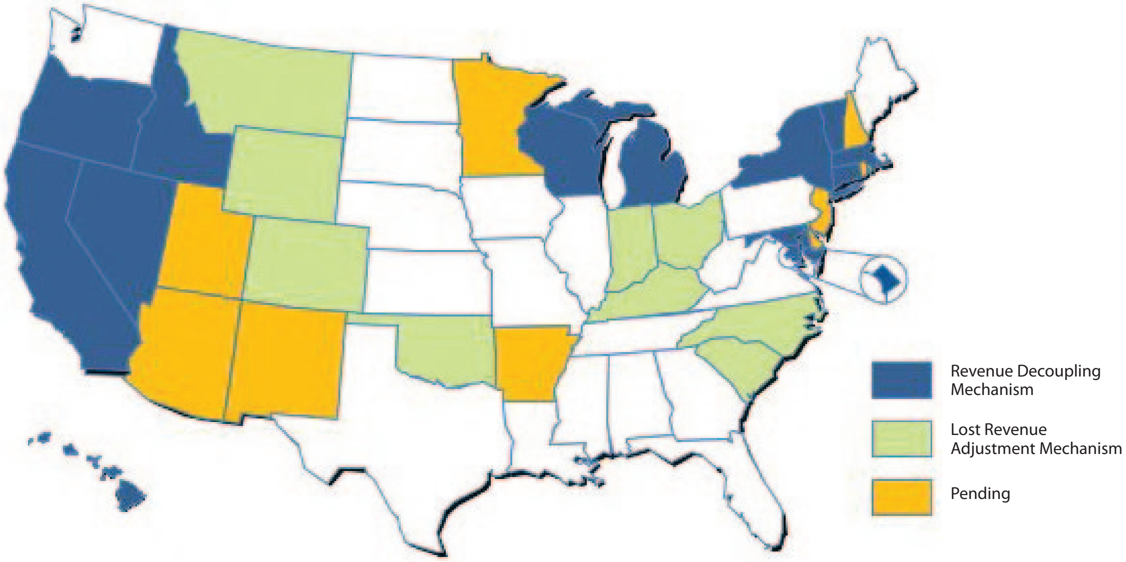
Popular forms of decoupling in the U.S. include revenue caps and revenue-per-customer caps. In a revenue cap system, the utility is assured of full recovery of a regulator-determined level of revenue over some period. At the outset, that total revenue is divided by expected sales (total kWh) to get a $/kWh rate. When actual sales deviate from expected sales, as they inevitably will, the volumetric rate is adjusted to meet the revenue requirement for the following period. In the revenue-per-customer approach, system costs are assumed to vary directly with the number of customers served by the utility company. Thus, the revenue cap is divided by the number of customers; rates are subsequently adjusted to reflect changes in the number of customers as well as to "true-up" for deviations of actual sales from expected sales.

As an alternative to decoupling, some states have adopted "lost revenue adjustment" mechanisms, which generally compensate utilities only for net revenue losses imputed to utility-based energy conservation programs. These partial programs do nothing to address customer-initiated changes in usage independent of those programs, however.

As of June 2011, 12 states and the District of Columbia had decoupling mechanisms, as illustrated in Figure 8.2. An additional nine states had lost revenue adjustment mechanisms. Another nine states were in the midst of proceedings to decide whether to implement decoupling.

Advocates of energy conservation are some of the strongest proponents of decoupling and describe its essential purpose as "reduc[ing] a utility's disincentive to promote energy efficiency" (for example, see Minnesota statute 216B.2412).[39] While decoupling does not provide the utility with incentives *for* conservation, it may help mitigate conflicts between the distribution utility's need for cost recovery and the policy goal of reduced electricity consumption, by eliminating incentives to maximize energy sales. Its impacts on cost recovery and effectiveness depend on the details of its implementation, which vary across systems. Decoupling does nothing to address the shift of transmission and distribution system costs from customers who are reducing their consumption through efficiency or distributed generation investments onto the remaining system customers.

Figure 8.2 U.S. States with Decoupling and Lost Revenue Adjustment Mechanisms, 2011



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Source: Institute for Electric Efficiency, "State Electric Efficiency Regulatory Frameworks" (Washington, DC, 2011).

Reliance on volumetric cost recovery may be particularly problematic when installations of distributed generation are subject to net metering. Under net metering, a kWh of generated electricity reduces a customer's bill not only by the avoided energy cost but also by the amount of the delivery service charge. The greater the quantity of electricity generated onsite, the less a customer contributes to cover the grid's cost. As discussed earlier, this implicit subsidy to distributed generation may reduce utility revenue in the short run if rates are not decoupled and will shift the burden of network costs to customers without (clean or dirty) distributed generation. This problem is more serious, all else equal, the greater the fraction of network costs that are recovered through volumetric charges and the less correlated a customer's peak net demand is with their total (gross) consumption of electricity. Similar distortions may arise for investments in energy efficiency or conservation under volumetric rate structures.

Reliance on volumetric cost recovery may be particularly problematic when installations of distributed generation are subject to net metering.

8.4 CONCLUSIONS AND RECOMMENDATIONS

Upward pressure on electricity rates will increase the value of more efficient transmission and distribution operations, and customer concerns with reliability and other dimensions of performance are likely to increase over time. Collecting and publishing comparable data on utilities' costs and service quality can help regulators evaluate and reward good, efficient performance.

RECOMMENDATION

Utility outcomes should be tied to performance metrics that allow for comparisons across utilities and over time. State regulators and others in charge of supervising utilities should develop and publish a consistent set of cost and performance metrics that allow these comparisons.

Performance measures should include progress on any policy goals imposed on distribution systems, as well as more traditional system quality and cost measures. These policy goals may include accommodation of distributed generation and electric vehicles, penetration of dynamic pricing, and distribution automation. If measurement is to have an impact, the results should be made public, and regulators should provide explicit incentives for good performance.

Traditional utility regulation has focused more on curbing monopoly power and avoiding excessive costs than on encouraging innovation. This emphasis is becoming increasingly expensive in an environment with rapid technological change and consequent potential for significant efficiency gains.

RECOMMENDATION

State regulators and others in charge of setting utility rates should design mechanisms for risk allocation and compensation to balance incentives for innovative, risky investment with efficiency gains and ensure that the results of innovative investments are shared with customers.

We endorse no specific mechanism. This is a hard problem that calls for creative experimentation, greater collaboration, and sharing of best practices across jurisdictions.

Recovery of fixed costs through volumetric rates ($/kWh) distorts the behavior of utilities and their customers. As distributed generation and efficiency investments become more widespread, the value of mitigating these distortions increases.

RECOMMENDATION

State regulators and those who supervise government-owned and cooperative utilities should recover fixed transmission and distribution network costs primarily through customer-level fixed charges, which may differ across customers but should not depend on energy (kWh) usage.

Fixed charges should vary with the extent to which customers contribute to the need for network development. This need might be approximated by past demand in peak periods or estimated by demand profiles. In systems that continue to rely significantly on volumetric charges for the recovery of network costs, utility incentives to increase sales can be blunted by decoupling utility revenues from short-run changes in quantities sold.

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