Regulating Distribution Utilities in a Restructured World

Regulators need to find a better way to determine local area capacity investments than the avoided-cost principles that are most commonly used.

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Within the context of electric utility restructuring, little attention has been paid to the effects on local distribution companies (DisCos). For the foreseeable future, DisCos will continue to provide a regulated monopoly service and will be the critical link between retail electric providers and their customers. This new separation between supplier and consumer raises two difficult planning issues: how to ensure a least-cost, reliable distribution system that meets a continuing "obligation to connect"; and how to allocate the costs of the necessary distribution system investments among customers and, possibly, retail suppliers.

I. Introduction

As the electric utility industry continues the hurly-burly of restucturing itself into a "competitive" industry, there has been a notable absence of discussion concerning continued regulation of local distribution utilities, sometimes called DisCos. For example, in the April 1998 issue of *The Electricity Journal* devoted to a discussion of "The Bumpy Road to Restructuring," there appeared articles on ISOs, stranded cost recovery, renewable generation, and markets for bulk power ancillary services, among others. Previous issues of *The Electricity Journal* have covered numerous aspects of restructuring, as have other academic and trade journals. But nowhere can be found a discussion of the fundamental regulatory conflict likely to exist between regulated DisCos and retail suppliers, and the problems that will arise as a result. In this paper, therefore, I will define this conflict and the problems it raises, as well as propose some initial solutions.

I will start in the next section by defining the nature of this conflict, which arises from the continuing "obligation to connect" of DisCos to provide the necessary linkage between competitive retail energy providers and customers. Section III will be devoted to a discussion of the first aspect of the conflict: determining appropriate distribution capacity investment strategies to meet uncertain future local peak demands and the weaknesses of using so-called "avoided costs" to do so. Section IV will cover the equity implications of assigning costs to different parties and the implications of those assignments on retail competition. Last, Section V will offer some suggestions for resolving the problems raised.

II. Defining the Conflict

To understand the potential conflict facing DisCos and regulators, consider the following example. Suppose a large, electricity-intensive industrial customer wishes to expand its manufacturing operations in the service territory of a particular DisCo. The expansion will likely lead to additional secondary growth in electricity demand as new suppliers, businesses, and households locate in the area in response to the manufacturer's expansion.

If there is retail competition, the manufacturer will seek the best possible deal for energy from competing energy suppliers. Those suppliers will be required to meet all applicable transmission system requirements (e.g., reserve capacity) to ensure that the transaction can be delivered to the DisCo. The DisCo will then be responsible for delivering the electricity to the customer. The DisCo will also be responsible for ensuring that there is sufficient distribution capacity to meet the secondary demand increases.

The potential for conflicting interests among regulators, the DisCo, the customer, and the retail energy provider is very real.

Now suppose that there is insufficient local distribution capacity to deliver the power as specified to the manufacturer for the expansion. Because of the natural monopoly characteristics of distribution services, DisCos are likely to have exclusive distribution franchises, much as integrated utilities have today.[1] Thus, the manufacturer is prohibited from constructing its own set of "wires and poles" in order to increase available distribution capacity to its facilities. This is the fundamental reason for the "obligation to connect" of a DisCo. Otherwise, the DisCo could merely refuse to develop new capacity in a local area and customers would be unable to obtain the electric services they wanted. Also assume that, like many integrated utilities today, the DisCo is required to use "least-cost" planning rules when determining new capacity investments. Those rules require the DisCo to meet new capacity needs at the lowest expected societal cost, whether through new investments in "wires and poles," local generation, or demand-side management (DSM).

The potential for conflicting interests among regulators (utility and environmental), the DisCo, the customer, and the retail energy provider is very real. The retail provider wishes to sell as much electricity as possible to its customer. The customer wishes to pay as little as possible to the DisCo for delivering the electricity it buys, and to not absorb the entire cost of new distribution system upgrades that may provide benefits to other customers in the area. The DisCo has an "obligation to connect" and cannot unilaterally refuse to provide service to customers who wish to increase their electric consumption. Utility regulators will not want to burden other ratepayers with the costs of expanding distribution capacity to benefit the manufacturer, but will have to work within the parameters of existing cost-allocation and rate-design rules. Environmental regulators' interests may not coincide

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with utility regulators' interests. For example, utility regulators may prefer local generation as an alternative to new distribution circuits, but such generation may violate air quality standards. Utility regulators may also wish to promote DSM or local generation investments so as to defer or obviate the need for any new distribution capacity.

Two questions must be answered: What is the most economically efficient strategy to meet customers' demands for energy at peak times, recognizing that demand will be uncertain? How should the resulting stream of current and future costs be allocated among different customers, including (possibly) retail electric suppliers?

Assuming the existence of an obligation to connect, the first conflict requires the DisCo to plan to meet future local area capacity demand in the presence of uncertainty. This may be made more difficult because, unlike under the existing system where the DisCo and the electric supplier are one and the same, the DisCo will probably not know the specific terms of the sale contract between the retail supplier and the manufacturer. This will introduce additional uncertainty into peak demand forecasting and will increase the difficulty of determining a "least-cost" investment strategy. Although it may be possible to offer interruptible power contracts to the manufacturer to reduce peak capacity and to delay or obviate the need for new distribution system investments, such arrangements will also have a cost.

The second question is probably the more contentious of the two. In the past, distribution expansion costs have rarely been allocated to specific customers, because of the public-good nature of the distribution system. Instead, distribution system costs have generally been allocated among customer groups based on standard methodologies developed for integrated utilities. This allocation scheme will likely change and, in doing so, will raise several issues. How will customer groups be defined? Will they be defined in terms of area-specific aspects, or will costs be allocated across different areas? Will individual local customers be allowed to pay the entire cost of an expansion that is not "least-cost"? Conversely, when will specific customers be required to pay the full costs of distribution system upgrades, and when will the costs of those upgrades be allocated among all customers, as is usually done today? What will happen if the peak demands that are forecast do not materialize? What will be the DisCo's planning obligations that define "prudent" behavior? How will regulators address inequities embedded in existing rate designs that misallocate costs that are collected on a fixed and volumetric basis? If regulators do not wish to increase fixed, "ready-to-serve" charges associated with distribution system costs, but instead collect those costs on a volumetric basis, how will customer equity be affected?

A key question: How should current and future costs be allocated among different customers?

In the frenetic world of electric utility restructuring, resolving these issues appears to have been ignored. Yet, a satisfactory resolution may prove crucial to the ultimate success or failure of retail competition, especially if a failure to correctly address these issues reduces system reliability, increases distribution costs, and limits retail competition.

III. The Least-Expected-Cost Distribution Capacity Expansion Plan

Regulators will require DisCos to use planning rules to determine appropriate local area capacity investments.[2] Some regulators are already developing such rules by extending the concept of avoided costs to determine cost-effective distribution investments.[3] Initially, the various methodologies to estimate utility avoided costs were developed to determine the required payments by utilities to qualifying independent power generators and small power producers under the 1978 Public Utilities Regulatory Policy Act. Subsequently, avoided costs became the basis for determining required DSM investments. The original intent was for these avoided costs to represent a utility's incremental cost for alternative energy supplies.

Developing avoided-cost streams may have been an appropriate way to price the energy provided by qualifying facilities, but it does not provide an appropriate guide for distribution system investment planning. The distribution investment planning problem fundamentally differs from the qualifying facility pricing problem. Although the reasons behind this conclusion about the inappropriateness (and, indeed redundancy) of using avoided costs to determine local area capacity investments can be found elsewhere,[4] I briefly summarize the arguments here.

The most common way in which the distribution planning problem has been defined is to develop a "base case" distribution investment plan and then to examine whether specific investments, such as a new substation or distribution circuit, can be deferred by distributed resources like DSM and local generation. The deferral benefit is simply the present value savings associated with deferring an investment for a given amount of time. For example, suppose that constructing a new substation will cost $11 million. If the utility's weighted cost of capital is 10 percent, then the deferral benefit from delaying construction of the substation for exactly 1 year will equal $11 million—($11 million/1.10) = $1 million. Suppose that peak loads will increase exactly 1 megawatt (MW) over the year. Then the "avoided distribution cost" will just be $1,000/kilowatt (kW) (= $1 million/1,000 kW). Under the avoided-cost reasoning, any distributed resource costing less than $1,000/kW would be a cost-effective alternative. This reasoning is straightforward, compelling, and utterly false.

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A consequence of this method is that alternative investments are used to defer traditional transmission and distribution investments for as long as possible without adding costs. That is what this concept of cost-effectiveness implies, and it is a fundamental flaw of the avoided-cost approach. What is cost-effective is not necessarily optimal, unless the objective is to maximize the amount of deferral provided by the alternative investments or (in what is the same thing) to maximize the penetration of alternative distribution system investments (DSM and local generation, for example) beyond the point at which they are part of the optimal solution.

Although avoided costs may be appropriate for determining payments to independent power producers, extending the avoided-cost approach to determine distribution capacity investments is wrong. In addition to the problem of cost-effectiveness versus least cost, the avoided-cost approach makes inappropriate marginal comparisons (deferring traditional distribution capacity investments either too long or too little, but never the correct amount) and, most importantly, does not incorporate future uncertainties, particularly uncertainty about future local distribution capacity demand.[5] Thus, as a methodology for determining appropriate investments in new local area capacity, using the avoided-cost approach will lead to higher-than-necessary costs for consumers. Poorly planned capacity expansions will also impose costs on retail electricity sellers and may lead to significant conflicts between those retailers, customers, and regulators.

So how should local distribution capacity planning be performed? First, it must be recognized that uncertainties at the local level will be magnified relative to overall system load uncertainties. The effects of one industrial customer's expansion plans are likely to be far greater in a specific local area than over a DisCo's entire service territory. Ignoring uncertainty in local capacity planning exercises, which most avoided-cost methods do,[6] will result in higher-than-necessary costs and possible reductions in service quality.

The correct approach to incorporating uncertainty is to recognize that local area distribution capacity planning requires recognizing that the problem is strategic, in that the investments are long lived, and dynamic, in that decisions and outcomes are interrelated.[7] Addressing the problem with an avoided-cost approach, however, treats the problem as a tactical, short-term exercise, where solutions are deterministic. Utilities and regulators have long recognized that traditional integrated resource planning should not be addressed this way; doing so for local area capacity expansion is even more important.

IV. Cost Allocation: Who Pays for Local Area Capacity Investments?

Even if least-expected cost distribution system investments have been determined, the more contentious issue of who pays for those investments remains. To address the issues involved, it helps to understand the nature of local distribution systems. Distribution systems have qualities of what economists call "public goods" and "club goods." Public goods are those where consumption by one individual does not affect consumption by another, while club goods are those that are uniformly provided by a "club" that an individual must belong to.[8] So, think of a DisCo as a local club that buyers (i.e., local electricity consumers) must join (pay an access fee) to receive club benefits (electricity bought on the market.)

Individual DisCo customers will have different demands for the specific public goods supplied, including peak capacity, voltage quality, reliability, etc. For example, slight voltage spikes are probably of little importance to

residential customers, but can severely damage some industrial customers' production facilities, resulting in large monetary costs. If voltage spikes are reduced by new system investments at the behest of the industrial customer, residential customers will benefit as well. In other words, residential customers will "free-ride" on the industrial customer but will have no incentive to pay for the improved voltage control.

The same arguments follow for increases in local area capacity. Because of the public good aspects, simply forcing individual area customers to pay for incremental increases in local area capacity may not meet existing regulatory definitions of equity. Nor may it be efficient, because individual demand for new capacity may be less than the cost of supplying large fixed increments of capacity. Observed increases in local area peak demand may be the result of random effects, such as weather, rather than actual shifts in customer demand because of new electricity-consuming equipment. Changes in observed peak demand may also be the result of changing rate structures. The difficulty of determining, in some cases, the causes of observed changes in local peak capacity demand can introduce what economists call moral hazard: because it is difficult for the DisCo to distinguish between random increases and structural shifts in demand, especially for small residential and commercial customers, allocating costs to individual customers is extremely difficult.

Presumably, these constitute some of the reasons that distribution system costs have historically been allocated among all customers of a utility by customer class, rather than on an individual customer or individual area basis. As retail competition takes hold, however, this allocation system may be challenged for other definitions of equity. It may also be challenged because of competing incentives among the different agents, who were previously subsumed under the umbrella of the vertically integrated utility.

V. Solving the Cost Allocation Puzzle

A. Alternative Schemes

Three alternative cost-allocation system options for new distribution system capacity investments appear to encompass the available range of options:

1. Preserve the existing allocation system in which capacity investments are allocated among all distribution customers using standard cost-allocation principles;
2. Identify customers specifically responsible for increased local area peak demands, and require them to pay all incremental expansion costs; and
3. Require some customers to pay for new local area capacity but allocate other costs across all distribution system customers.[9] (The actual payment mechanism, such as alternative distribution tariffs for individual customers or local-area-specific tariffs, is an additional issue, which I do not consider here.)

The choice of cost-allocation mechanism is complicated by two factors: (1) differences between private and social costs of providing desired levels of service; and (2) competing definitions of equity. For example, depending on the chosen cost-allocation principle, regulator requirements for minimizing social costs (so-called "societal tests") can conflict squarely with consumer sovereignty,[10] while allocation schemes based on cost causality may conflict with social goals of affordability and universal service.

To clarify the available alternatives and the issues they raise, consider the following example. Peak demand in a local planning area is near the capacity of the local distribution system. The local area is dominated by a single manufacturing customer. This customer wishes to double the size of its operations. The precise timing of this expansion depends on a range of future uncertainties, from projected growth in the national economy and the likely expansion plans of competitors to obtaining necessary state and local land use and environmental permits.

Suppose that local area capacity is 100 MW under normal operating conditions (not accounting for temporary overload situations,) and that current peak load in the area is 95 MW and increasing at 1 MW/year. The manufacturer drives the local area peak load and has a separate metered peak load of, say, 75 MW. Should the facility expand, its metered peak load is expected to increase to between 120 and 140 MW, far above the available distribution capacity into the area. If the expansion proceeds, it will also generate additional ancillary economic development in the area, including new housing, schools, and service industries, which are expected to increase peak demands of between 2 and 6 MW/year, depending on future electric prices, economic growth, and a variety of other uncertainties, including weather. The manufacturer is currently served by a single retail provider, or RetailCo, which anxiously awaits expansion of the facility so that it can increase electric sales. Other RetailCos serve the remaining local area loads.

The DisCo, therefore, faces a capacity expansion problem under uncertainty, as described in Section III. Suppose the DisCo determines that the least-expected cost decision is to build initially a new 40 MW capacity substation and install 5 MW of DSM capacity. The costs of these investments total $10 million, $5 million each for the substation and the DSM.

Under "traditional" ratemaking principles, joint distribution system costs have generally been allocated by customer class, rather than by geographic area of service.[11] Although many alternative methods have been used to allocate costs, holding individual customers responsible for the full incremental costs associated with having sufficient installed distribution capacity to meet increased peak demands has not been a standard cost-allocation practice.[12] This is especially true for residential customers, the vast majority of whom are not as yet metered on a peak-demand basis.[13]

Preserving the Existing Cost Allocation System. Under the existing system of allocating costs by customer class, but not by specific service area, any investments in new capacity would be rolled into the overall class distribution rates for customers of the DisCo.[14] In this case, DisCo customers outside the specific area of growth could be adversely affected by the manufacturer's expansion.[15] These customers might have an incentive to oppose the manufacturer's desire to expand and would want the DisCo regulator to seek lower-cost alternatives, such as interruptible service.[16] They might also advocate allocation of all of the incremental costs to the manufacturer. The manufacturer and the RetailCo will both have an incentive to maximize the capacity expansion benefits while paying a minimum of the incremental costs.

Uncertainty as to the magnitude and the timing of expansion complicates the cost allocation, because the DisCo will necessarily have to invest in new capacity prior to expansion. Although this is parallel to the existing regulatory issues faced by integrated utilities today when deciding on the magnitude and makeup of incremental investments in generation resources to meet customer energy requirements, there are some differences. The major difference occurs because the DisCo will be responsible to meet customer distribution capacity needs, but will have no influence over the terms and conditions for energy sold to customers.

The existing allocation methods are based on traditional definitions of customer classes, but those customer classes may no longer be appropriate in a restructured world. Customer class definitions will depend, in part, on how regulators allocate existing distribution system costs, as well as incremental investments.

Allocation to Specific Customers. The economics and regulatory literature has addressed the issue of allocating joint costs. Usually, local distribution system investments have been considered joint costs for the benefit of all ratepayers. In some circumstances, it may be possible to identify specific distribution investments that provide benefits to only a subset of clearly identified customers, usually large industrial or commercial customers.[17]

As restructuring takes place and separate DisCos are formed, there is likely to be greater regulatory pressure for those DisCos to identify specific customers who are driving the need for new local area capacity investments. Regulators may face political pressure not to impose new distribution costs on customers in general, so as to deliver on promises of lower-cost electricity service to all classes of customers. This pressure may be exacerbated by the structure of distribution rates developed by the regulators. To the extent that fixed distribution costs are allocated on a volumetric (per kilowatt-hour) basis, consumption decisions will be affected more than if these costs are allocated on a fixed, ready-to-serve charge basis. Because many of the distribution costs are fixed, and the marginal cost of providing off-peak local area capacity is, for all intents, zero, recovering distribution capacity costs on a volumetric basis will be inefficient. This inefficiency will exacerbate inequities and will complicate the cost-allocation question.

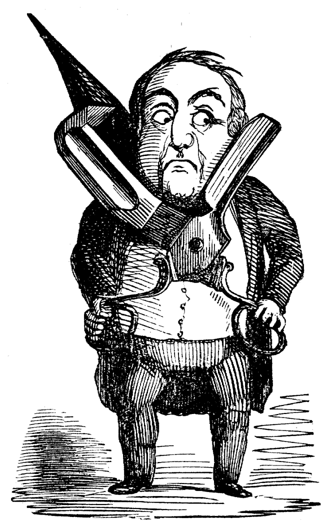
Mixed Allocation Schemes. A third option is for regulators to assign distribution system capacity investment costs directly to certain individual customers but to allocate other costs to groups of customers. This option can be thought of as a subset of existing allocation systems, but replacing groups of multiple customers with groups of individual customers. The option represents a theoretical ideal in terms of equity: allocate non-joint costs to the customers driving the need for new investments but allocate joint costs more globally. Thus, if there are no other customers in the same area as the industrial facility, then asking that customer to pay the expansion costs is reasonable and appropriate. This solution, however, may assume away the very difficulties likely to be encountered: multiple beneficiaries and joint costs. Last, any mixed cost-allocation scheme will be scrutinized by those identified as specific beneficiaries, much as there are often disputes about cost allocations among different customer classes.

The benefits of increasing capacity may also improve other local system characteristics that benefit all customers, though to varying degrees. For example, industrial customers such as computer chip manufacturers will likely value improvements in system reliability and power quality more than the average residential customer. Both parties benefit, however, when system improvements are made. Although it is theoretically possible to charge separate prices for these public goods, doing so would require empirical identification of each customer's demand curves for those goods.[18]

B. Developing a Workable Cost Allocation Solution

In the context of what is equitable, unique cost-allocation solutions simply do not exist. What is fair for one local area customer may not be perceived as fair by another, especially if those customers consume fundamentally different DisCo services.

Historically, regulators used traditional fully allocated cost (FAC) rules to share investment costs among customers. Regulators further addressed equity concerns by also adjusting prices; commonly, "ready-to-serve" charges were set much lower than their "true" cost, because minimum bills several times larger than current levels have not been politically viable.



Yet cost-allocation decisions can be, and should be, separate from rate structure decisions. Thus, the first step in any cost-allocation scheme is to adjust prices correctly: Ready-to-serve charges should be raised to their real levels; and regulated volumetric charges, if any, should reflect only those DisCo services that truly vary with consumption. This will allow consumers to make efficient choices about their electric consumption and to allow DisCos to plan more effectively for future capacity needs.[19]

If electric restructuring is to be successful, any chosen cost-allocation scheme should be judged by its effect on overall economic efficiency. The best allocation scheme will meet specific, and well-defined, equity goals with the least adverse impact on economic efficiency. Although the existing FAC system has a proven track record, it was designed for a fully regulated and integrated system. As that system is replaced with a mixed competitive-regulated framework, it will be faced with new types of costs, customers, and suppliers, none of which may fit within the traditional framework.

Last, developing an allocation mechanism should also account for transaction costs. Cost allocations should be as straightforward as possible, so as to minimize the regulatory and legal costs necessary to determine them.

VI. Conclusions

At this time, the problem of local area capacity investments has not been addressed adequately. The avoided-cost principles commonly used to determine local area capacity investments are wrong, and the issue of how to allocate capacity investment costs equitably has not been adequately addressed. Because of this, regulators may find themselves embroiled in complex allocation issues and controversy governing the obligations of DisCos to provide access to local area capacity and specific levels of service quality. To ignore these issues, therefore, will be a disservice to customers and retail suppliers, and it is likely to reduce the potential benefits of competitive generating markets. ■

Endnotes:

1. It can be argued that there may be cost-effective substitutes for distribution, such as microturbines. But by "natural monopoly," I simply mean that it is less costly for one supplier to provide distribution services than it would be for two or more suppliers to provide the same quantity of services.

2. For the purposes of this paper, I am ignoring investment decisions solely for service improvements such as voltage support.

3. See, for example, VERMONT DEPARTMENT OF PUBLIC SERVICE, STATEWIDE ENERGY EFFICIENCY PLAN, Appendix 5, May 1997.

4. Mathematical treatments can be found in C. Feinstein and J. Lesser, *Defining Distributed Resource Planning*, ENERGY J., Special Issue, 1998, "Distributed Resources: Toward a New Paradigm of the Electric Business," at 41; J. Lesser and C. Feinstein, *Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules*, J. REGULATORY ECON., forthcoming 1999; and C. Feinstein, P. Morris, and S. Chapel, *Capacity Planning Under Uncertainty: Developing Local Area Strategies for Integrating Distributed Resources*, ENERGY J., Special Issue, 1998, at 85.

5. See J. Lesser and C. Feinstein, supra note 4 for further development of these points.

6. For example, H. Kroll and R. Rosen 1994, "Nine Fallacies in Computing Avoided Costs," Paper presented at the 1994 Annual National Association of Regulatory Utility Commissioners (NARUC/NASUCA) Conference, state that uncertainty should be dealt with after calculating a stream of avoided costs. J. Busch and J. Eto, *Estimation of Avoided Costs for Electric Utility Demand-Side Planning*, ENERGY RESOURCES, 18 (June 1996) at 473–499, completely ignore load growth uncertainty and, for that matter, any other type of uncertainty. Such approaches, by definition, cannot determine least-expected-cost expansion strategies.

7. Feinstein, Morris, and Chapel, supra note 2, develop a better approach to solving the planning problem.

8. An analogy to a warehouse buying club may be helpful. To join a warehouse club, customers pay an annual fee used to defray the various fixed costs associ-

ated with maintaining the club. Nonmembers are excluded from the club's services.

9. A fourth possibility is to require retail providers to pay for all or a portion of local area capacity expansion costs directly. This seems unlikely, as retail providers would have difficulty monitoring demand and cannot affect distribution system pricing structures.

10. In a recent rate case in Vermont, one of the witnesses for the Vermont Dept. of Public Service suggested that, even if an industrial customer were willing to pay the entire cost of a distribution system upgrade, if it were less costly on a societal basis to meet that customer's demand for additional capacity with demand-side management investments for residential customers, then the industrial customer's request should be denied. See deposition of Paul Chernick, Docket No. 5983, TARIFF FILING OF GREEN MOUNTAIN POWER CORPORATION, Oct. 27, 1997 at 39.

11. See, for example, C. PHILIPS, THE REGULATION OF PUBLIC UTILITIES, Public Utilities Reports, Inc., 1984, Ch. 10.

12. One of the reasons for passage of the 1936 Rural Electrification Act, for example, was to make access to electricity affordable in rural areas of the country, precisely because the incremental costs of providing service were large.

13. This is the primary reason for requiring load profiles for different customer classes so that capacity costs can be allocated to retail service providers fairly.

14. Customer classes can themselves change with the advent of retail competition. Equity and economic efficiency impacts will depend on the specific rate structures for DisCo services adopted by regulators. These issues are beyond the scope of this paper.

15. This is a classic pecuniary externality.

16. Some customers may believe that the economic development benefits associated with the industrial expansion outweigh the direct monetary costs imposed on them because of the expansion. Alternatively, they may conclude that the present value costs imposed on them will decline with a larger customer base.

17. One example of this is equipment located at a customer's site to improve voltage control.

18. This is known as Lindahl pricing. See E. Lindahl, "Just Taxation: A Positive Solution," in CLASSICS IN THE THEORY OF PUBLIC FINANCE, eds. R. Musgrave and A. Peacock, New York, Crowell-Collier (1958).

19. "Second-best" concerns, where distortions in one market are compensated for by distorting another, may occur. However, it is not clear whether regulators can compensate for market distortions in an efficient manner, especially as the volatility of electric markets increases.