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ELECTRIC RETAIL MARKET OPTIONS: THE CUSTOMER PERSPECTIVE

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SUMMARY

This report describes various options that are now available for retail electric customers, or that may become available to them during the next few years as the electric utility industry restructures. These options (Table S-1) include different ways of meeting demand for energy services, different providers of service or points of contact with providers, and different pricing structures for purchased services. Our purpose is to examine these options from the customer's perspective. What might be involved in a customer's using an option? Why might a customer like or not like an option? What processes are at work to make the option available or to limit its availability? How might the options interact? In short, how might being a retail electric customer in 5-10 years differ from being one now?

Table S-1. Retail Electric Customer Options

Procurement Options: (Chapter 2)	
	Self-generation
	Self-service wheeling
	Alternate energy carriers
	DSM or energy services
	Relocation
	Purchase
Purchase Options: (Chapter 3)	
	Local utility
	Municipalization
	Bilateral contracts
	Broker
	Poolco (wholesale)
	Customer-owned transmission
Pricing Options: (Chapter 4)	
	Cost-based
	Performance-based
	Time-of-use
	Negotiated

Much of the current discussion of utility restructuring and retail options has focused on opportunities for customers to reduce their cost of service.

However, seizing these opportunities is likely to entail working with different service providers. From the customer's perspective, cost of service also includes the amount of effort required to learn about, evaluate, and choose among various service providers and ways that they can provide service—what are known as transaction costs. If utilities or groups of customers perceive that the transaction costs of dealing with each other will be high they may forego some options. In addition, customers place value on other aspects of service in addition to electric rates and transaction costs. Customer satisfaction can depend on how the service is delivered; the range of options made available for choice and how well these options match customer preferences; the length of time that a customer must commit to use a service option; and the risk that conditions of service (e.g., price, convenience, reliability) for a chosen option may change relative to other options.

Some of the options are likely to be riskier for the customer than others, and some of the options may become available in different forms to different groups of customers. Because some of the options we discuss have only been introduced on an experimental basis, and because others have been proposed but not yet implemented, this report is necessarily speculative. However, an examination of these differences from the customer's perspective will help to identify barriers or opportunities for making options more available.

Some of the options that are beginning to emerge seem likely to be transitional. These include relocation, customer-built and -operated transmission lines, some efforts at municipalization, and possibly self-generation and long-term contracts with suppliers. These options are attractive for some customers under the present structure of the electric utility industry, and the availability of these options may stimulate change in that structure. However, they entail risks to the customer if the industry changes, because they respond to present conditions—such as large differences in electricity prices from different suppliers—that may diminish in a restructured industry.

Other options depend on how restructuring is achieved and what effect it has on customers. This group includes municipalization prompted by the desire to reduce prices for small customers. This option may become more common in a restructured industry, as a way of ensuring that small customers share the benefits of restructuring. However, if restructuring occurs in ways that promote active retail competition for these customers, municipalization might be unnecessary. Brokers seem likely to become more common unless restructuring takes the form of mandatory poolcos, in which case the services of brokers probably would be less valuable than with a restructuring (including less restrictive forms of poolcos) that relies more on contracting. Mandatory poolcos, performance-based rates (PBR) for generation, and bilateral contracts (other than contracts for differences (CFDs)) in their basic forms appear to be largely incompatible with each other, although some elements of each could co-exist under some forms of restructuring. Thus a customer is unlikely to be offered a choice among them once restructuring has happened.

Some options appear robust. That is, they seem likely to become more common regardless of how restructuring is accomplished. Increased competition among energy carriers (gas versus electric) and real-time pricing (RTP) pricing appear likely to increase in any event.

This report identifies some of the qualitative differences among the various options on these dimensions. For some customers, particularly those who use large amounts of electricity, different alternatives are likely to have great differences in the price of service, transaction costs, ability to tailor service to customer preferences, and risks for the customer. Other retail customers, perhaps primarily those who use small amounts of electricity, may find little to distinguish among the options except the price of service.

LIST OF ACRONYMS

CBR	Cost-based Rates
CFD	Contract for Differences
DSM	Demand-side Management
FERC	Federal Energy Regulatory Commission
kWh	Kilowatt-hour
NOPR	Notice of Proposed Rulemaking
NUG	Non-utility generation
PBR	Performance-based rates (or ratemaking)
PSC	Public Service Commission
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act of 1978
ROE	Return on equity
RTP	Real-time pricing
T&D	Transmission and Distribution
TOU	Time-of-use (rates)

INTRODUCTION

For much of the past 60–70 years, the principal option for a firm or household to obtain electricity has been to purchase it from the local electric utility. Residential customers have effectively had one option available—to purchase kilowatt-hours (kWh) of electricity, as and when demanded, at a schedule of prices (rates) set by a regulated electric utility or, less commonly, a government-owned utility. The price schedule typically set a price per kWh, and it often included an additional fixed charge for each customer. Often the price paid per kWh has been based on the number of kWh consumed. Commercial, industrial, and other customers effectively have had the same option, but the schedule of prices often has been more complex, depending upon the customer's peak demand for power as well as the number of kWh consumed. In some instances special classes of customers—low-income households, very large users, or government agencies—have been offered additional rate options. For example, a low-income household might be entitled to buy up to some specified number of kWh at a price lower than households that purchase more than this amount; large industrial users might have the option of paying a lower price but being subject to infrequent interruptions in electricity supply.

Other retail options either have not been cost-competitive or, because of the way that electric utilities have been regulated, have not been offered. Some customers have been able to switch from electricity to other energy sources for some but not all of their needs, and customers have had the option of moving to areas served by utilities that charged lower rates, but once established in a location a customer has had very little choice about how to buy electricity.

During the past 15 years, additional options have become available to some retail customers. These include:

- lower-cost technologies for generating electricity (e.g., co-generation), often with a government requirement that a local utility purchase excess electricity not needed by the customer, in lieu of generating its own;

- Time-of-use (TOU) rates, in which the price charged for a kWh varies with the time it is consumed, usually according to a schedule of prices announced well in advance; and

- energy audits and other demand-side management (DSM) programs in which utilities help customers identify ways to reduce electricity consumption and make the reductions.

During the past two years, there has been much discussion of additional options that may become available, including:

- allowing a customer a choice of electricity suppliers via retail wheeling or negotiated contracts;

- creating a pool of electricity suppliers to serve all customers in a region;

- creating opportunities for brokers to match customers with suppliers;

- using dynamic TOU rates, also known as real-time pricing (RTP), in which the price paid per kWh is determined at the time the electricity is generated, rather than well in advance;

- Using performance-based ratemaking (PBR) to cap rates while increasing the flexibility of pricing options;

- increasing the number of municipally-owned utilities, primarily as distribution utilities; and

- building direct transmission connections to neighboring electricity suppliers.

Much of this discussion has been prompted by provisions of the Energy Policy Act of 1992. In some regions of the country, discussion and experimentation have been prompted by large differences that some retail customers —especially large industrial users—have observed in the cost of obtaining electricity service from different suppliers. Those paying high prices have sought to develop lower-cost options and to remove restrictions that prevent their doing so.

The purpose of this report is to describe the various options that may become available to retail electric customers during the next few years, and to examine them from the customer's perspective. What might be involved in a customer's using an option? Why might a customer like or not like an option? What processes are at work to make the option available or to limit its availability? How might the options interact? In short, how might being a retail electric customer in 5-10 years differ from being one now?

Much of the current discussion of retail options has focused on opportunities for customers to reduce what they pay for electricity service. However, seizing these opportunities is likely to entail working with different service providers, and is it likely to involve different practices in transacting business with them. Some of the options are likely to be riskier for the customer than others, and some of the options may become available in different forms to different groups of customers. or provide different levels of customer satisfaction. This report is necessarily speculative, but an examination of these differences from the customer's perspective will help to identify barriers or opportunities for making options more available.

Although by far the most common option for retail customers is to purchase electricity from the local utility, there are alternatives to purchasing. Chapter 2 discusses these primary options. If the customer chooses to purchase power, there are or may be several alternatives to purchasing from the local utility, as discussed in Chapter 3. In addition, restructuring of the electric utility industry could change what is meant by the local utility. Finally, if the customer chooses to purchase, there are or may be several options in the way prices are set. Chapter 4 discusses these pricing options. Table 1 shows the structure of the report and the options discussed.

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	Time-of-use
	Negotiated

PROCUREMENT OPTIONS FOR RETAIL CUSTOMERS

Customers have a number of ways that they can acquire the services normally provided through electricity. Although the most common by far is to purchase from the local utility, there are alternatives to purchasing. These alternatives include generating one's own electricity; using alternate energy carriers such as natural gas to meet some needs; improving electricity end-use efficiency to reduce demand; and relocating. This chapter discusses each of these options.

SELF-GENERATION

Many large industrial customers and some large public agencies such as universities and transportation systems have found that, by using waste energy or steam from their processes to turn generators, or by generating electricity and using the waste heat to meet other energy needs, they can provide a large fraction of their own electrical needs at a cost below what they would pay to purchase electricity from a utility. Some even produce enough to sell back to the utility. This type of cogeneration became popular through the 1980s, encouraged by the requirement in Section 210 of the 1978 Public Utility Regulatory Policies Act (PURPA) that utilities buy the excess power at the utility's avoided cost. With gas prices low and new technology making smaller generation sources economical, more customers have joined the ranks of self-generators. In 1993, non-utility power generation at manufacturing sites totaled 221.3 billion kWh, compared to utility sales of 977.2 billion kWh to industrial customers (EIA 1994b) (Figure 1); some of this generation at manufacturing sites may have been electricity generation without use of waste heat.

A customer interested in generating its own electricity should do a detailed analysis of its operations and processes to identify where self-generation or cogeneration would yield the greatest benefits, and an analysis of alternative technologies and designs for the generating equipment to identify the least expensive option. If custom design of equipment is necessary, the costs of the analysis and design are likely to limit the use of this option to only large industrial users. If equipment can be purchased off-the-shelf and installed without modification, as in some "package" cogeneration systems for space and water heating by commercial users, more customers are likely to find this option attractive. Suppliers of such equipment may be more likely to actively market to these smaller customers, increasing the customers' awareness about this equipment. Self-generation also requires a commitment by some one—the customer or a third-party developer—to the additional maintenance, fuel purchase, and operation activities entailed in producing electricity. In principle self generation also requires a commitment to monitor internal costs and electricity prices to determine whether to continue the practice, and a willingness to assume the risk that changes in electricity market conditions or the customer's demand will make continued operation of the equipment uneconomical.

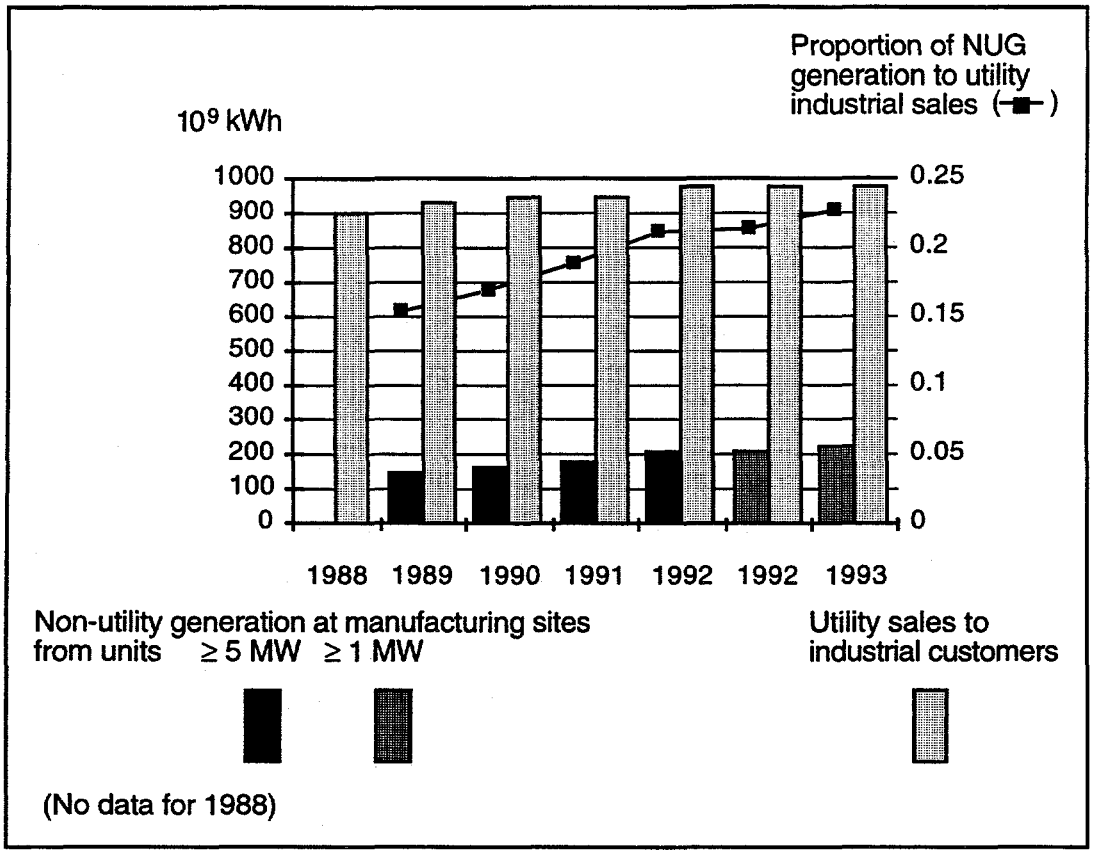

Figure 1. Growth in non-utility generation (NUG) at manufacturing sites and utility sales to industrial customers (Source: EIA 1994a; EIA 1994b).

In addition, a decision to self-generate may entail negotiations with the utility to provide backup service under a tariff, or the development of other plans to deal with supply outages. If the customer plans to generate more electricity than it needs and sell the excess to the utility, it also will need either to negotiate with the utility about the amount and price of the electricity it will sell, or apply for qualifying facility status under PURPA, which would require the utility to purchase the excess at the avoided cost of generating the electricity itself.

Despite the additional burden of analysis, negotiation, and operation, some customers will find it financially advantageous to generate their own electricity, benefitting from reduced bills for electricity, for other energy, or both. In some instances, if a large customer simply announces that it is considering self-generation, the utility may respond by negotiating lower rates or offering to build or operate the self-generation equipment on the customer's premises. Some large customers may find it attractive to make such proposals to gain this kind of bargaining power, although their proposals need to be credible in order to exercise it. In July, 1994, the New York Public Service Commission (PSC) adopted a policy that allows utilities to individually negotiate flexible rates with customers who have realistic alternatives to continuing to receive service from them (EEI 1994). In this sense, self-generation becomes one option for negotiating terms of service, including price (discussed in Chapters 3 and 4).

Utilities tend to be concerned about self-generation, especially by large customers, because departure of large customers from their customer base may cause some of their existing equipment with high unrecovered capital costs to become "stranded," or unneeded to meet demand and therefore unable to generate revenues to pay off the cost of their construction. The PSCs that regulate utilities also tend to be concerned about self-generation, because of the possibility that large reductions in demand may make utilities financially less viable and may require higher rates for customers that continue to receive service from the utility. This concern is reflected in the New York PSC's policy mentioned just above.

Three factors appear to account for much of the interest in self-generation. First, new technologies have reduced the size of generating equipment required for cost efficiency (Moore 1993). Although this has been particularly noteworthy for combustion turbines, improvements in other technologies (such as package cogeneration systems for residential customers and renewable energy systems for remote customers) have also made it possible for some customers to generate electricity in smaller amounts at lower cost than from the utility (El-Gassier 1995). As the cost of electricity from more technologies has fallen below the average cost of electricity from the utility, more customers have found self-generation attractive. Second, low fuel prices, especially natural gas, have contributed greatly to the low cost of new generation. Third, as noted earlier, PURPA established a requirement that the utility purchase power from qualifying generating facilities at its avoided cost of generation, and a requirement that the utility interconnect with the generator and as necessary provide backup power. PURPA thus provided a market for some self-generated power.

All of these developments also may operate indirectly to reduce the attractiveness of self-generation. First, the changes in technology have helped to begin processes such as restructuring that are likely to reduce the cost of service from utilities and other electricity providers. As high-cost utility investments are either paid off, or stranded and written off, and as expansion and replacement of generating capacity uses less expensive new technology, the cost of service from the utility (or other entities that result from restructuring) should decline, reducing the difference in cost between self-generated and purchased power. To the extent that customers believe that these outcomes are likely, they may see new investment in self-generation as risky or potentially burdensome in comparison with other electricity service options. To the extent that these outcomes are realized, customers will find self-generation financially less attractive than at present, especially for new investment in self-generation equipment. To the extent that utilities or other electricity suppliers gain flexibility to negotiate terms of service and price with their customers, they may negotiate prices that make self-generation less attractive. Alternatively, as in the recent contracts concluded between Detroit Edison and the "Big 3" automakers, they may seek to negotiate limits on the use of self-generation (Michigan PSC 1995). Under these contracts, Detroit Edison will compensate these three customers for self-generation capacity idled under the contracts (the PSC deferred decision on ratemaking treatment of this compensation but left open the possibility that the costs might be borne entirely by shareholders).

Second, these same developments are reducing the avoided cost of generation that utilities are required to pay under PURPA, and they raise the possibility that present contracts entered into under PURPA may themselves become stranded, or that self-generators may be required to renegotiate these contracts. There have been proposals to repeal Section 210 of PURPA, which governs these contracts (Burkhart 1995); some proposals would honor existing contracts, others would open them for renegotiation. Repeal of Section 210 would make it difficult to develop new self-generation projects whose financial viability depends upon this guaranteed market for excess power. Even without repeal or reform, FERC and the courts are taking a sterner view on approving new contracts or bids that have prices higher than avoided costs (Radford 1995a).

This conclusion must be qualified, however. Some have argued that in a more flexible electricity market, operating with improved telecommunications and control technologies that allow real-time pricing and dispatching of dispersed generating resources, self-generating capacity could become a resource that might be dispatched (Newcomb and Byrne 1995; Douglas 1994). This practice might be done in lieu of interrupting service to the customer, or as a way to maximize the overall efficiency of electricity markets.

SELF-SERVICE WHEELING

Closely related to the option of self-generation is that of self-service wheeling, in which a customer has several facilities, some of which can self-generate, and wishes to use excess self-generated power from one facility to meet demand at another.

Most of the discussion of self-generation in the preceding section is applicable to self-service wheeling as well. However, because of the multiple locations involved, exercising this option requires the use of utility transmission lines to wheel the power among the customer's plants or, as proposed in two cases in Texas, the construction of transmission lines among the facilities (Energy Daily 1995). Maine law allows self-service wheeling over existing lines (Elcon 1995), but the status of this option in other states is less certain. In Texas, the proposal to build new lines requires public utility commission (PUC) approval, and the firm that plans to build the lines would be subject to current utility regulations if the PUC approves. In Michigan, the petition that led to the establishment of that state's retail wheeling experiment was made by two groups (Michigan PSC 1994). One of these was an association of industries, and although its primary motivation was to seek access to less expensive electricity supplies, it also petitioned that each of its members be allowed to self-service wheel among its plants (the association apparently did not request permission to wheel between members). The Michigan experiment will allow the requested self-service wheeling. However, the recent contracts negotiated between Detroit Edison and the "Big 3" auto-makers limit the use of self-generation and therefore the potential for these customers to self-service wheel.

At present, the added complexity involved in determining whether self-service wheeling is permitted, or in requesting permission for it, probably limits the use of this option to customers who already have self-generation facilities. To the extent that various proposals to restructure the utility industry are realized—to allow retail wheeling, sales and purchases from power pools, or the use of brokers—present barriers of institutional uncertainty over self-service wheeling will diminish in importance, but so also should the financial advantage of doing so. With a restructured utility industry, some electricity that could be self-service wheeled may be sold to other customers, and higher-cost self-generation may be displaced by less expensive purchases from other sources.

Although self-service wheeling is a straightforward concept in the case of a multi-plant firm, the principle can be applied more broadly. In Michigan, the second of the parties that petitioned the PSC to allow retail wheeling was a group of universities that wanted to self-service wheel among themselves (Michigan PSC 1994). The Michigan retail experiment will allow self-service wheeling among members of this group, although some member of this group will not meet the voltage requirements set for participation in the experiment. The PSC's decision to allow the university group to self-service wheel among group members raises the possibility that other groups could be formed for the same purpose. If restructuring of the industry allows customers greater flexibility in buying and selling electricity, the question of what constitutes a legitimate group that is entitled to self-service wheel may become irrelevant. However, if self-service wheeling is allowed while retail wheeling is restricted, this question would assume increasing importance.

SWITCHING ENERGY CARRIERS

Many customers can meet their demand for some electricity end-uses, such as space heating, water heating, and process heat, using direct combustion of fuels rather than electrical technologies. Residential and industrial customers frequently have the option to use electricity or natural gas for space heating and water heating, and they may be marketed by both types of utilities to continue with their present service or to switch. It is not uncommon for a gas or electric utility to offer incentives for customers to switch from its competitor, and a few electric utilities have even offered incentives for present electric customers to switch to gas as a form of DSM. A number of utilities supply both electricity and natural gas services, and in a more competitive environment they may develop strategies that encourage some of their customers to switch energy carriers within the company.

Retail customers are likely to continue to see competition between gas and electric utilities for their various heating and other end-use demands. If utility restructuring and technological change reduce the cost of electricity, this would reduce the cost advantage that natural gas has for space and water heating in many parts of the country. Moreover, to the extent that electricity suppliers become more reliant on natural gas, the added demand for gas should increase the cost of gas, and this might further improve the relative position of electricity. Both of these trends would tend to make electricity services more cost-competitive with gas and cause a relative expansion of the electricity market compared to the gas market. Technological change in electricity generation also would reduce the present cost penalty that utilities experience when their loads increase, which would make marketing programs to build load more attractive. Electric utilities might well become more active in offering incentives designed to overcome various behavioral barriers that reduce customer responsiveness to changes in prices (e.g., greater priority by end-use customers and building contractors on appliance purchase cost than life-cycle cost, tendency for equipment replacement to occur under emergency conditions following equipment failure), as a way of encouraging them to switch from gas.

However, to the extent that electric utility restructuring leads to increases in electricity prices for residential and small commercial customers, as some observers fear, these customers could experience price increases for both gas and electricity. Without more information about the relative increases in prices of the two energy carriers, or in the allocation of costs of providing service, it is difficult to speculate on how either type of utility would view this portion of its market. Similarly, the effects of improved end-use technology for both gas and electricity are difficult to ascertain; one analyst suggests that improved end-use technologies have tended to favor the use of natural gas, but that improved electric heat pumps may help electric utilities recapture market share (Bielski 1995). It is likely that electric utilities would take some action if they foresaw large scale loss of residential and commercial markets to natural gas, even if this were a gradual process. However, the form of such a response (purchase incentives for appliances, restructuring of rates) in a restructured industry is difficult to predict. In addition, to the extent that residential customers perceive heat from burning gas as providing greater comfort than heat pumps, these customers may be less sensitive to differences in price than others whose energy needs could be met by either energy carrier.

DSM OR OTHER ENERGY SERVICES

Retail customers now participate in DSM programs in several ways. A utility may interact directly with the customer, by providing incentives to purchase different end-use equipment, by installing the equipment directly, or by providing information about alternative ways of using electricity. Because of this interaction, some utilities have seen DSM as a useful tool for customer relations (more commonly, utilities have seen DSM either as a system resource to develop, or as valuable customer service). Alternatively, instead of interacting directly with its customers, a utility may contract with an energy service firm to perform these functions for selected classes of customers. A utility also may sponsor competitions in designs for buildings or end-use equipment that improves end-use efficiency, with the customer interacting only with the result of the competition and not the utility. A utility may work with state and local governments to promote building codes that increase energy efficiency. State and local energy agencies, and nonprofit service organizations, also may work with retail customers to help them improve the efficiency of their electricity use. Many of the utility activities have been required directly by state law or PSC rules, or indirectly through requirements that utilities undertake integrated resource planning.

Some large industrial customers have objected that DSM programs targeted by their utilities toward residential and commercial customer classes increase the industrials' cost of electricity. Some also have objected to DSM targeted toward industrial users, because they believe they know their own operations well enough to decide what DSM steps make most sense for them. Utilities, concerned about the cost of their product in a more competitive electricity market, have also been considering and making reductions in DSM programs as a way to reduce costs. Part of the historic justification for DSM programs has been that they help avoid the need for high-cost investments in expensive new generating resources, and the risks associated with these investments (Hadley and Hirst 1995). As new generating technology reduces these costs, it also reduces the force of this argument.

Given these objections and trends, it seems likely that in the future the participants in utility-operated DSM programs will have to bear a greater share of the costs of these programs. This requirement probably will reduce the level of utility-sponsored DSM activity. Utilities may become more important as sources of information and facilitators of financing, and less important in direct installation of energy-efficiency equipment. Utilities also may continue DSM but restructure it in ways that help them to become better acquainted with the needs of their large customers, or with groups of customers who might switch to other sources of electricity supply.

As an example, under the terms of its contracts with the "Big 3" automakers, Detroit Edison will assign some of its employees to work at the facilities of these customers to identify opportunities for saving electricity and meeting customer needs for power quality or other elements of service. Details of what these employees will do, and how they will do it, remain to be worked out. This feature of the contracts apparently was motivated by the utility's interest in becoming more responsive to customer needs and better able to retain its industrial customer base. Another motivation appears to have been the utility's desire to respond to continued PSC interest in industrial DSM. However, this aspect of the program may have had lower priority for the customers than others, and the customers may have agreed to it as being less objectionable than other DSM programs. To the extent that the utility pushed for the program in response to PSC interests, this type of DSM program might be a transitional one that would become less common if the electric utility industry is restructured to give PSCs less influence or authority over negotiated contracts between customers and suppliers. To the extent that the utility recognized this as an opportunity to strengthen its relationships with its customers, this type of DSM program might continue.

Another option for providing DSM is for a city or state agency to take over some DSM functions (Tonn, Hirst and Bauer 1995). This option would respond to concerns by some who view DSM as a type of government social program or as a public policy whose costs have been shifted from taxpayers to ratepayers (as opposed to a system resource that utilities can acquire). When there is a public benefit to increase energy efficiency, then it may be appropriate to make this function a public one, especially if utilities operating in a competitive environment believe that DSM places them at a competitive disadvantage. Retail customers in jurisdictions that operate DSM programs might continue to receive DSM services that are similar to those now provided by utilities, with a public agency and its contractors replacing the utility and its contractors; the agency could even contract with the utility to deliver the service. However, there is increasing interest in reducing government activity and spending, and there is increasing competition for limited public funds in most large cities. As a result, advocates of public delivery of DSM services (or of public contracting for private delivery of these services) are likely to find it more difficult to develop support for direct public involvement in DSM than they did for requiring utilities to undertake DSM.

The city of New Orleans seems to be moving in the direction of delivering more DSM services, according to a state group advocating energy efficiency. The borough of Tarenton in Pennsylvania is in the process of establishing its own utility and has received support from a foundation to support its efforts to develop a DSM program. Several cities that recently have either formed their own municipal utilities or considered doing so have made DSM a part of their plans for municipalization (Schweitzer 1995). They have cited a desire to reduce their costs or make their customer loads less expensive to serve when they purchase power from wholesale suppliers. It is too early to determine the scope of these programs. Given the importance of large industrial customers to some of these municipalization efforts, some of these DSM programs may also focus on customer relations and solidifying the industrial customer base of the new utilities.

Finally, private energy service companies may continue to provide not just energy efficiency services, as they now do under utility-sponsored DSM, but also a broader range of energy counseling and energy services. The services might include an audit, recommendations to improve end-use efficiency in some areas of a customer's operation, recommendations to increase energy consumption (perhaps by changing process technology) in other areas, or recommendations to change energy carriers for some end-uses (Houston 1994). A number of existing electric utilities are in the process of forming or purchasing energy service companies as unregulated subsidiaries. These companies are expected to focus on large customers, and to offer services that include power quality, facility management, fuel procurement, and on-site generation (Demand-Side Report 1995). The utilities involved include Southern California Edison, Public Service Electric & Gas in New jersey, Potomac Electric Power in Washington, DC, Boston Edison, PECO Energy in Philadelphia, and Eastern Utilities Associated in Massachusetts. It is conceivable that some energy service firms might also offer brokering services to identify and contract with electricity suppliers. Reimbursement for these services might be by flat fee, by some proportion of estimated cost savings, or by some proportion of present expenditures on electricity.

RELOCATION

A retail customer has the option of moving from a location with high electricity prices to one where prices are lower. However, most commercial customers require good access to their markets. Residential and most industrial customers seem unlikely to relocate for lower electricity costs alone, given that for most their electricity bills are a small proportion of their total expenditures. Moreover, some activities (e.g., ski resorts, irrigated agriculture, and some mineral processing facilities) are tied to site-specific resources. Relocation is an expensive step for most types of customers and, although the relocation itself provides great flexibility, once accomplished it tends to reduce available choices for several years while the relocation costs are paid off or recovered.

Nevertheless, businesses do relocate, and those that operate at multiple locations do shift activities among them. In some of their activities the cost of electricity is a significant part of the cost of the final product. Although a decision to relocate or to shift production is unlikely to be prompted by electricity costs alone, these costs may become a factor once the customer begins to consider such a decision. The utility may view such a decision as a potential threat and respond by negotiating changes in the terms of service offered to the customer, including lower prices. Alternatively, it may respond by seeking approval from the PSC to take other steps to retain the customer. The Ethan Allan furniture manufacturer in Vermont threatened not to relocate, but to forego expansion and reduce production at its plant there, unless it could pay lower electricity prices (EEI 1994). A negotiated settlement has apparently been worked out to satisfy its concerns. In Massachusetts, the Raytheon Corporation has threatened to relocate production to another state unless it can obtain a 40% reduction in its electricity prices (*The Electricity Journal* 1995). One of the utilities that supplies Raytheon has obtained PSC approval for a 20% reduction, but environmental and interest groups may challenge the agreement in court. Once utilities begin to make these kinds of responses, customers may begin to threaten relocation as a way of prompting this sort of negotiation and concession.

To the extent that other trends in the electric utility industry operate to reduce electricity prices overall, or to make more options available to customers seeking lower electricity costs, or to reduce the disparity in electricity prices that now exist from utility to utility, customers will be less likely to justify relocation on the basis of electricity cost savings alone, and their threats to relocate for this reason will become less credible. Thus, present concerns of utilities that their customer base may relocate because of electricity costs are likely to be valid only in the short term, and they probably will diminish as electric utilities restructure. Customers still will relocate or shift activity, and utilities may continue to work with them to try to retain them as customers, but for most customers electricity costs will not be a significant reason for an interest in moving. Other factors, such as transportation, labor, taxes, public services, and access to markets, are likely to be more important. If restructuring of the electric utility industry were to take greatly different forms in different parts of the country, yielding great differences in the kinds of service and pricing options available to retail customers, these differences among regional options might assume some importance for some firms. These options are discussed in Chapter 3.

PURCHASING ELECTRICITY

Unless a customer chooses self-generation or self-service wheeling to meet all of its demand, it will need to purchase at least some electricity. Much of the discussion of utility industry restructuring has focused on changes in how electricity will be sold and purchased, and in how prices will be set for service. Chapters 3 and 4 take up the major options being discussed.

PURCHASE OPTIONS FOR RETAIL CUSTOMERS

Any discussion of how customers will go about purchasing electricity must be conditioned by the present uncertainty about how the electric utility industry will be restructured. Based on current discussion about restructuring, and current measures being taken by utilities, PSCs, and customers in different states, there is a reasonably good chance that many retail customers will be able to choose from at least some of the following options. Although in some options the question of how the service is provided probably will be linked closely to how the utility sets a price for the service, this chapter focuses on the former and leaves discussion of the latter to Chapter 4.

CONTINUE PRESENT ARRANGEMENT WITH PRESENT UTILITY

Some classes of customers, particularly residential and small commercial ones, may want to continue to purchase electricity from their present electric utility just as they do now. This option may remain available, with the utility subject to different forms of rate-setting regulation than at present (Chapter 4). Alternatively, restructuring of the utility industry may split up the present utility, with a distribution company or customer services company (Figure 2) assuming the function of providing service to the final customer (and handling billing, service calls, and other types of interaction now provided by the utility). This option would be compatible with forms of electric utility restructuring in which present utilities continue to operate distribution systems but purchase electricity from a pool, from some other generator of power, or from a broker.

Under a change in the form of rate regulation (Chapter 4), customers who remain with the present utility might see a difference in electricity prices but otherwise experience little difference in the way the utility treats them. Under a restructured industry, a distribution company or customer service company also might provide service in a manner very similar to the present utility, again with the customer seeing only a difference in price. However, it is possible that a distribution company might become more active than present utilities in DSM or load-shaping activities, if it can improve its profits by improving the match between the demands of its customer base and the cost, timing, and quantity of electricity available from its suppliers. Although the specifics of such interaction would depend on the form of restructuring and the available contracts for electricity, it is conceivable that a distribution company might seek to increase electricity sales among some customers or encourage reductions among others.

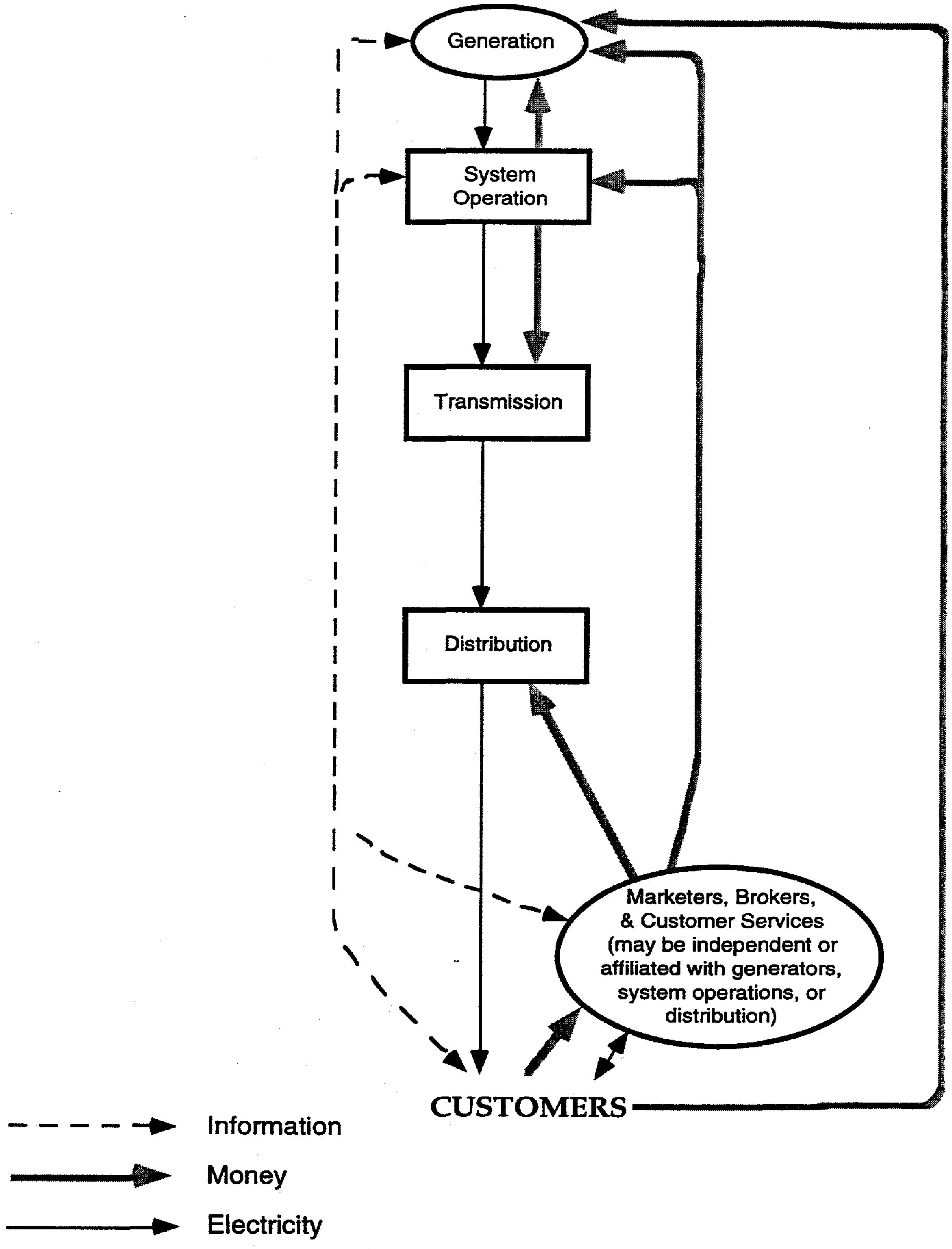

Figure 2. Flows of information, money, and electricity in a restructured electricity industry.

Alternatively, real retail competition might develop for residential and small commercial customers. In this cases these customers might continue to receive service as at present but experience heavy advertising and other promotions from competing electric utilities or other electricity suppliers to get them to sign up with one utility or another—not unlike what has developed in the retail long-distance telephone market. For example, Utilicorp of Kansas City has established a brand name, EnergyOne, to market its gas and electricity services nationally. Whether different utilities would be able to offer real differences in price and service, or whether they would just focus on trying to create the perception of real differences, cannot be determined at this time.

It is conceivable that utilities might market using several strategies: how they generate their electricity (fuels, technologies, environmental quality); how much they charge for service; how they set prices (e.g., flat rate vs. various forms of TOU pricing); what options they provide to help customers alter their use of electricity and thereby save money (e.g., DSM, incentives to switch from competing energy carriers); or what options they provide for auxiliary services (e.g., DSM, wire maintenance, quality of tree trimming around power lines, various transmission and distribution services) that might reasonably be marketed to small customers. Marketing strategies could be strongly affected by how much flexibility customers would have in switching suppliers as conditions change, and by whether service promotions can offer reductions in downside risk (e.g., guarantees to match competitors' prices to all customers who sign up during a promotion period). This would be especially true during a period of transition from the present utility industry structure to whatever structure eventually emerges.

This kind of retail competition would require a form of electric utility restructuring in which the utility that owns the distribution system would have to allow competing suppliers access to its customers, i.e., retail wheeling. Restructuring that focused on creating a mandatory wholesale poolco (see below), might not be compatible with this form of retail competition unless it also allowed generators to sell to the pool based on the amount of demand subscribed by their customers rather than just on the basis of the price charged to the pool. The concept of contracts for differences (CFDs) encompasses this kind of arrangement, but it is discussed in a later section on poolcos because it probably would appear quite different to the customer than the present form of utility service.

One form of retail competition that might emerge among small customers could be affinity marketing, such as "green power" buyers' clubs or other groups of customers who are willing to pay more for electric power generated using non-polluting technologies (NREL 1995). By banding together, the aggregate purchasing power of the members could become large enough for potential suppliers to enter into contracts to develop the "green" supplies and deliver the electricity from them. Similar kinds of affinity groups might be organized around other characteristics of service or causes the people support, but it is difficult to speculate at present on what these alternatives might be for small customers. However, voluntary organization of any such affinity group may be difficult, given the difficulty that utilities have had in finding participants for similar groups (NREL 1995). Retaining members in the group, so that it can honor its contractual commitments, may also be problematic. If such groups can be formed and sustained, they might compete for membership.

Affinity groups aside, large industrial customers are likely to have more retail options than small customers because of the size of their demand for electricity, their sensitivity to price, and the ability of their staff to develop expertise in energy matters. Competition for their business may be more likely to take the form of negotiation, brokered sales, or contracts, as discussed in a later section.

CREATE A MUNICIPAL UTILITY

Some municipalities operate their own electric utilities, generating some or all of their electricity while purchasing the remainder at wholesale from other utilities, and selling the electricity to their local customers. Several municipalities that historically have not operated their own electric utilities have recently explored the option of doing so, as a way of reducing the cost of electricity to their citizens or large employers, or to gain greater independence (Schweitzer 1995). To the extent that retail competition in a restructured electric utility industry focuses on large customers because of their potential market power in electricity markets, municipalization could allow small customers to cooperate through their city government to achieve additional bargaining power and lower costs. In addition, municipalities pay no taxes, have no shareholders requiring dividends, and often have access to capital at lower rates of interest than do private utilities; these factors also should permit municipal utilities to charge lower prices for electricity. However, recent Federal Energy Regulatory Commission (FERC) policy as outlined in recent decisions and its notice of proposed rulemaking (NOPR) states that departing customers from a system will have responsibility for stranded costs (FERC 1995). This will serve to discourage municipalization as a means to escape high-priced local utilities.

Residential customers in some locales are likely to be surveyed to evaluate their support for municipalization. They also may be lobbied both by supporters and by opponents of municipalization. Otherwise, despite the range of options available to the municipality in setting up its new utility (again, discussed by Schweitzer 1995), the principal difference the small retail customer would experience under municipalization is likely to be the price paid for electricity. In most cases, the costs of establishing and operating the new utility (e.g., acquiring, installing and maintaining distribution systems, negotiating with suppliers, and billing for service) would be covered by the price charged customers for the electricity, so municipalization need not involve tax increases or competition with other municipal activities for revenue once the new utility is established. If the utility that serves the city opposes the municipalization effort, as most seem to do, city residents could experience some short term increase in taxes to pay the cost of litigation.

Schweitzer (1995) notes that although one case of municipalization reduced rates for its customers as expected, other customers who continued to be served by the original utility experienced even greater reductions in rates. The new municipal utility is contractually bound to its new supplier for 15 years. Hence, during a period of transition in electric utility industry structure, municipalization may be a risky strategy, because it could commit customers to a mode of service more expensive than what might result from other restructuring. Once the new industry structure and its effects on different classes of customers become apparent, this risk may diminish.

The prospects for additional municipalization depend on how utility industry restructuring proceeds (especially the treatment of stranded costs) and the effects that it has on electricity prices. To the extent that other forms of restructuring have the effect of reducing the price that utilities charge all customers, municipalization may be a transitional activity—attractive now, when neighboring utilities sometimes charge greatly different prices, but less attractive if prices and differences among prices are lower. Limited amounts of municipalization could place additional pressure on utilities and PSCs to undertake such restructuring and contribute to such a general reduction and leveling of prices. However, if restructuring tends to lead to greater benefits for large industrial customers, municipalization could be an alternative to provide some of these benefits to small customers, and it might become even more common.

Schweitzer notes that large industrial customers may be much more active than small customers in the process of proposing and planning a municipalization effort. In one case the city needed a commitment from a large customer that it would purchase from the new utility before the city was willing to proceed with the effort. In another city, the large industrial customer underwrote legal and planning costs for the municipalization effort. Large industrial customers could take the initiative in proposing municipalization.

BILATERAL CONTRACT WITH GENERATOR

Bilateral contracts between retail customers and suppliers, specifying terms of service and price, are common in the natural gas industry. However, the physical characteristics of electricity and the way in which electricity service has been regulated have limited their use in the electric utility industry. In a loose sense, this is how retail customers now receive service from their electric utilities, but the service agreements are standardized for customers within large customer classes—"one size fits all, take it or leave it"—so there really is no negotiation and most customers do not even see a contract. The terms of service available under these agreements are specified in tariffs filed by the utility with the PSC and subject to PSC approval.

Under some forms of utility industry restructuring, negotiated contracts could become much more common while PSC review would occur less frequently, if at all. In the absence of a requirement for PSC review of the contract, the supplier and the customer might exercise greater flexibility than at present in negotiating the prices and characteristics of electricity service. A customer might contract with multiple suppliers to provide electricity at different times, or it might aggregate electricity from several generators to meet its peak demand. These suppliers might include its present utility (or successor distribution company), other utilities, or other suppliers (what are now called independent power producers or non-utility generators).

Contracts might cover not just the quantity of electricity, time of delivery, and price, but also ancillary services such as reliability, power quality, DSM, and customer service. Prices may be fixed within the contract or indexed to an industry-recognized standard. Alternatively, industrial customers, such as aluminum smelters, could have prices tied to the market price of their product. Large retail customers may negotiate futures contracts for the receipt or delivery of electricity to hedge against fluctuations in electricity prices, although this type of contract may be used more by electricity suppliers, brokers, and financiers than by most retail customers. As with the natural gas and other commodity markets, a large financial derivative market could develop that separates the physical and financial aspects of the commodity.

As Kirby, Hirst, and Vancoevering (1995) note, present electricity service involves a complex bundle of attributes beyond the simple delivery of energy and power. Some of these services make retail service more reliable, and others improve the quality of the power delivered. The recent FERC NOPR also addresses ancillary services (FERC 1995). Technical means exist for some of these attributes (e.g., local reactive-power management, power quality) to be supplied by the customer, and some customers may prefer to do without purchasing them if this would mean a lower price for service. Other service attributes, such as time correction and stability enhancement, must be obtained from the electricity system operator. Negotiated terms of service may allow customers flexibility in choosing and paying for the attributes they want from the service supplier, and in providing some of these services for the utility. For example, in an experimental program offered by Niagara Mohawk to some of its large industrial customers, the customers clearly found greater value in uninterrupted service at high cost for short periods of time than in having service interrupted for the same periods (Douglas 1994).

Negotiation can be time-consuming and expensive, and estimating the implications of different contract options can be complicated. For these reasons, the primary users of negotiated terms of service are likely to be large commercial and industrial users with both the resources needed to conduct the negotiations and the potential for large savings. In addition to the resources required for negotiating a contract, bilateral contracts also involve risk, especially while the utility industry is in transition, of committing to terms that may not be as favorable as those that may become available later. A customer might reduce this risk by negotiating a clause within the contract to reopen negotiations if conditions change. Alternatively, the customer might be able to purchase some form of insurance.

Smaller customers might find that a larger menu of service options becomes available to them, either because negotiations by large customers establish patterns or because other forms of restructuring occur. However, the benefits of negotiating more favorable terms for a small customer may be less than the resources required by the negotiation. In California, a program to allow small natural gas customers to negotiate bilateral contracts for natural gas has had less participation than originally expected; this results in part because the gas utilities have reduced their operating costs and prices to levels that leave little margin for small customers to find lower prices from other suppliers. Moreover, many of the participants in the program have entered into agreements negotiated cooperatively (e.g., fast-food franchisers negotiating for franchisees, one state agency negotiating terms of service for other agencies).

PURCHASE THROUGH A BROKER

One way for customers to reduce the time and cost burdens of negotiating more favorable terms of service is to make use of brokers. A broker might identify available options for service, screen them for their suitability for different customer clients, and handle the details of establishing the contract for service. A broker might assemble packages of alternative services and market them to groups of customers, or it might consolidate the demands of a number of customers and enter into negotiations with suppliers. Brokers might be active developers of markets, or they might be more passive and respond to requests for service from retail customers. If electricity becomes tradeable in commodity exchanges then brokers could be active in the full realm of financial transactions, including hedging through options, futures, swaps, and other derivatives.

From the customer's perspective, brokers could increase the service options available while reducing the amount of additional information the customer would need to deal with. This would make benefits of utility restructuring available to more and smaller customers than a system in which each customer negotiates its own terms of service. A broker might even take on some of the marketing functions now performed in a simpler market by utilities, creating a larger number of standard classes of service, including reliability and power quality attributes, and marketing them to customers. Or an existing utility, using its established relationship with its customers, might develop its own brokerage business and put together contracts selling power from its own plants, bulk purchases from wholesale suppliers, and energy services such as DSM. Brokers might well compete with each other on the basis of price, quality of service, or options for managing risk.

Customers are not always assured of the lowest prices available on the spot market as with a poolco approach (see below). If the broker signs contracts with suppliers who have higher costs, customers of that broker will pay higher rates. In addition, the customer will face the difficulty, common to other kinds of brokered markets, of finding a trustworthy, competent broker. In the initial phases of market restructuring, it is unlikely that there will be standards for training or licensing brokers as there are in other brokered markets. Experience in those markets indicates that training and licensing are not necessarily guarantees of competence. In addition, there could be differences in how brokers price their own services, as opposed to the prices they negotiate for electricity service. Some might charge a flat fee or use a sliding scale based on the size of the contract; others might charge a percentage of what the customer pays for electricity, while others might charge a fee based on the amount they save their customers. A utility that provides brokering services might find its fees regulated while those of its competitors are not.

As with negotiated contracts, the potential for electricity brokering depends upon how utility restructuring proceeds. If restructuring follows a mandatory poolco approach, brokers may not be able to provide as much added value. Under the poolco approach, a customer effectively buys from a utility but at prices determined by the poolco's operation.

PURCHASE FROM A POOLCO

There has been much discussion of the possibility that utility restructuring would proceed by establishing a separate organization—called a poolco—that would dispatch electricity generating capacity to meet demand and maintain system reliability (Hogan 1995). Although details of different proposals vary, from the perspective of retail customers the key detail is whether or not the poolco is a wholesale poolco, or whether it allows retail access.

Under the former, individual generators would submit bids for how much they could generate, at what price, over some short time period such as an hour or half-hour. The poolco would accept the bids in order of lowest price and only let those operate. Prices paid to each generator could be based on any of several different factors: its bid, the highest bid accepted, the lowest bid not accepted, extra payments based on the relative availability of capacity, etc. Under a wholesale-only poolco, a local distribution utility (perhaps a municipal utility, perhaps a private company) would be the purchaser of power from the pool. Retail customers would pay the distributor based on the pricing methodology that it uses, which could be any of the methods described in Chapter 4. Aside from a change in price, retail customers might see little difference between this arrangement and their present service.

The United Kingdom has restructured its electricity generation system using a mandatory wholesaling poolco. There is some concern that in the British poolco the generation owners are large enough to retain some monopoly power and influence the poolco's operations and prices (Hogan 1995), so that retail prices are higher than they might be if there were more generation owners, each having a smaller share of the market.

From the point of view of the retail customer, retail service with this form of poolco should be similar to service in regions of the United Service where tight power pools, such as the New England Power Pool, now operate. Changes in the operation of such pools to accommodate additional suppliers and pricing mechanisms probably would not be noticed by the retail customer except for changes in price. Such a poolco would tend to provide a uniform quality of service, and it probably would be difficult for distribution companies to offer different levels of service or to compete for retail customers.

Under a second poolco option, electricity suppliers and customers (retail customers, distribution companies, or brokers operating on the behalf of suppliers and customers) would negotiate bilateral contracts with each other. Electricity suppliers would deliver electricity to the poolco, and retail customers would receive electricity from it. The poolco would handle the technical coordination of matching supply with demand, possibly including transmission, and it would also create a short-term spot market for electricity suppliers and customers to match electricity demand and supply (Hogan 1995). An intermediary company—perhaps the existing electric utility, perhaps a municipal utility, perhaps something reorganized from existing utilities, perhaps the poolco—would handle transmission, distribution, and billing. Customers would pay prices based on RTP, plus any extra, regulated charges for transmission and distribution (T&D) and system services. The customer might receive an itemized, consolidated bill from the distribution company for electricity, transmission, distribution, and other services, in a way that telephone customers typically receive a bill from a regional phone company that covers services by local, regional, and long-distance companies. From the perspective of the retail customer, the process of obtaining service would be very similar to that described earlier for bilateral contracts, with the poolco and possibly a distribution company as intermediaries to provide brokering functions.

With a poolco, if the marginal cost of power is less than the current system average cost, customers should benefit from lower prices because they will purchase power from the poolco essentially at the marginal cost of power. However, the cost of power supplied to the pool is likely to vary over time because of seasonal, daily, and hourly variations in demand and the cost of generation to meet different levels of demand. As a result, customers would see monthly variations in electricity prices on their bills. As discussed in Chapter 4, TOU rates might be established to encourage customers to change their consumption behavior and reduce the monthly variation in prices and bills. Or, as many utilities now do, the billing utility might offer an annual price or a constant monthly bill based on the customer's previous year's bill, to be adjusted each year and settled upon termination of service. Such an arrangement would make customers less sensitive to changes in price, but many customers might prefer to be billed in this fashion.

Another option for customers to reduce price variability could be to negotiate a CFD with a specific supplier to the poolco. Under a CFD, the customer would continue to pay the pool operator at the pool price, and the operator would forward payment to the supplier as in the second poolco option. In addition, the customer and the supplier would make up for any differences between the contract price and the pool price. If the contract price is above the pool price the customer would pay the difference to the generator, but if the price is below the generator would pay the customer. Hogan argues that CFDs are functionally equivalent to bilateral contracts and could cover the range of financial functions that an active commodity market provides. Just as with the commodity and futures market, it is likely that only large consumers would get involved with CFDs for price and supply hedging.

During the California PUC hearings on its proposal for creating retail direct access, arguments were raised both for and against the development of a poolco (CPUC 1995a; 1995b). Although proponents of restructuring the electric utility industry into poolcos anticipate that customers would eventually experience lower prices, this result will depend in part on how the poolcos are created and operated, and what existing utilities do with their generating capacity. If utilities retain ownership of their capacity, or if other suppliers have a large share of the supply market, they may be able to exert market power on the poolco market, earning additional revenue and increasing the cost to the ultimate customer (Hogan 1995). The recent proposal by a majority of the California PUC (CPUC 1995b; Radford 1995b) would restructure elecrricity generation by the state's three large investor-owned utilities into a mandatory wholesale poolco. The three utilities would retain ownership of their generation, which would leave this concern open. However, all other producers in the region could voluntarily enter the pool, thereby diluting somewhat the market power of the large utilities.

Similarly, if the poolco operates primarily as a technical coordination intermediary for bilateral contracts, it is possible that some customers will be able to lock in favorable rates from some suppliers, leaving other customers to be served from higher-cost suppliers. In theory this should not happen with a competitive poolco, because the low-cost suppliers should be able to find buyers willing to pay more than their cost of production (but less than the market-clearing price), but customers and suppliers do not always act as theory predicts. The California majority PUC proposal would not allow bilateral contracting, at least for the first two years of the poolco's operation, and the wholesale nature of the poolco proposal would not accommodate operations by brokers or other intermediaries (Radford 1995b).

CUSTOMER-OWNED TRANSMISSION LINES

Customers in several states have proposed to build transmission lines to neighboring utilities that offer lower prices than their present utilities. For example, Motorola is negotiating to build a line from its factory in northern Illinois across the borders of the state and of its utility's service area to a substation in Wisconsin owned by Wisconsin Power & Light (EEI 1994). In Texas, a company is proposing to build a transmission line between two large industrial facilities owned by another firm. This will enable the facility owner to self-service wheel to one of the facilities from a cogeneration facility at the other, bypassing the utility. The municipal utility in Bryan, Ohio, and the new municipal utility formed in 1989 by Clyde, Ohio also built transmission lines to new suppliers.

Transmission lines represent a large capital investment whose cost per unit of capacity or energy increases greatly with distance; longer lines therefore can be justified only where larger differences in price exist. Transmission construction projects typically require approval from the PSCs that regulate the customer's present and new utilities; such projects also require negotiations with landowners, and possibly approval from state and federal environmental protection agencies. For such projects to be cost-effective, the customer must consume large amounts of electricity and expect a long-term price disadvantage from the local utility. Because of the present uncertainty about the future structure of the utility industry and the cost of service from alternative suppliers, this option is probably among the riskiest now available to a retail customer or to a city representing their interests. Some customers may hope that the threat alone can cause the utility to offer lower rates. If the present movement toward some form of utility industry restructuring were to fail, then customer construction and ownership of transmission might become more common. Otherwise, it seems likely to be a transitional activity that becomes less attractive as restructuring reduces prices and the differences in prices charged by neighboring utilities.

Customer construction and ownership of transmission is likely to encounter opposition from the existing utility, which would not want to lose a large, high-load-factor customer (the customer probably uses a large amount of energy relative to its peak needs; otherwise, the peak-related capital cost of the transmission lines would make the lines uneconomic on a per unit energy basis). The PSC may be reluctant to approve the project because of the damage it does to the territorial franchise concept. A restructuring of the utility industry that weakens this concept would also reduce the incentive for customers to build their own transmission lines.

PRICING OPTIONS TO RETAIL CUSTOMERS

Unlike options for purchasing electricity, many of which are still evolving and which will depend on how the electric industry is restructured, most of the options for pricing sales of electricity are already in use in one form or another, although most are not yet in widespread use. The focus of the following discussion is on how these pricing options may interact with different restructuring options and on how customers may respond to them.

COST-BASED RATES

Cost-based pricing is the present method of pricing most electricity service in the US (Bonbright, et al. 1988). A utility submits a request to the state PSC to allow it to charge certain rates or prices for service, along with detailed data and analysis on its costs and sales. The commission reviews the request and supporting documentation, holds public hearings to receive opinions from other stakeholders affected by the rates, and makes a decision. Key questions revolve around the appropriate amount of return the utility should be allowed, how much of its investment or expenses have been "prudent" and therefore recoverable from prices charged to customers (as opposed to being borne by the utility shareholders), and whether it has pursued an integrated resource plan. Once the PSC determines the overall amount of revenue allowed, it must establish the amounts to be collected from each customer class, and from that the electric rates for each class. It is typical for residential customers to pay a fixed customer charge and a separate charge based on the number of kWh purchased. Other customer classes may pay a lower per kWh charge but also pay a charge based on the size of their peak demand for electricity, regardless of when that peak occurs. Some groups of customers —such as low-income residential customers—may pay according to special rate schedules.

Cost-based pricing provides several benefits to customers. Under cost-based rates, a utility is relatively assured of making a sufficient return on investment to enable capital formation. This assurance has lowered the cost of capital, which allows the utility to undertake construction of generation and T&D facilities at lower cost and pass the savings along to its customers. By grouping customers into a relatively small number of classes, and by defining classes of service, the system reduces the amount of information that utilities need to provide customers about service options, and that customers need to gather about supply options. Components of service (electricity, reliability, infrastructure maintenance) are bundled together and priced as a unit, which simplifies decisions to purchase service. Electricity rates change infrequently relative to the frequency of change in electricity costs, which can vary greatly from hour to hour. Prices are fixed, rather than negotiated in each transaction, so the transaction costs for customers are lower than they otherwise would be (although they can remain high for the utility in ratemaking hearings before the PSC). In some cases, rates from larger or more well-off customers are used to subsidize some of the costs for low-income customers which creates a benefit for the latter. To the extent that utilities retain some or all of their monopoly power, the present system prevents price discrimination (charging higher prices to customers who do not have alternatives than to those who do) and can promote a reasonably equitable allocation of costs among customers. These benefits are difficult to quantify, but they are real.

Offsetting these benefits are the regulatory system's slow speed in responding to changes. This slow pace can delay increases in costs from being passed along to customers, but it also can delay reductions in cost from being passed through. Regulation of prices on a cost basis also forces the utility to devote a large amount of resources to justifying rather than reducing costs, which further adds to the cost that must be borne by the customers. Politically influential groups can influence regulatory bodies more readily than an open market, causing the utility to provide programs or charge rates that are not consistent with the utility's cost of doing business but that may have other redeeming values. Examples include DSM programs, lifeline utility rates, lower rates for certain industrial classes, promotion of renewable energy systems and protection of environmental values. Other offsetting characteristics include the subordinating of individual customers into classes, and the increased rates some customers pay to cross-subsidize services to other classes. In general, the cost-based pricing regulatory system provides only limited incentives for a utility to reduce costs when it can instead pass them along to customers who have very limited alternatives to purchasing from the utility. The rules established by PSCs for determining which costs can be recovered in electricity prices (e.g., "used and useful") can lead the utility to make decisions that later appear uneconomic if conditions change. Some of these undesired effects of the present cost-based rate regulatory system are difficult to quantify, while others are relatively easy.

The present interest in utility restructuring begins with the premise that unwanted costs of the present system of regulation outweigh the benefits, especially when the present system has allowed utilities to build and bill for generating capacity that is more expensive than what the electricity market is now offering. What remains uncertain is the type and kind of change needed to undo these unwanted costs of the present system. The present cost-based system is incompatible with bilateral contracts between customers and suppliers, whether negotiated directly or brokered (Chapter 3). To the extent that restructuring involves poolcos or additional municipal utilities, the electricity generators would no longer be subject to cost-based pricing, although the distribution companies might remain so.

PERFORMANCE-BASED RATES

Under PBR, a utility's prices are regulated not on the basis of its costs, but on the basis of performance criteria. Performance criteria can be established for specific portions of a utility's operations, such as a nuclear plant, or they can be set for its entire operations. Formulas for calculating performance and prices would be adjusted for inflation, general improvements in productivity, and costs beyond the utility's control. Periodically, the rates would be "trued up" to reflect costs. However, between these periodic re-settings, if the utility can perform better than the performance criteria, then it can generate profits greater than those defined by the formula based on them.

There are several options for instituting PBR. Under one option, the PSC could set a price cap on the average revenue a utility earns per kWh. A cap might be set for the utility's entire sales, or it might be set differently for different classes of customers. The utility would be free to negotiate different prices as long as average revenue remains below the cap (Ackerman 1995). The principal benefit of rate caps is that they give the utility additional flexibility in setting prices to meet competition while offering customers some protection against price increases. The larger the number of rate caps set for different customer classes, the more the PSC can protect specific customers from rate increases, but the less flexibility the utility has to set prices. Rate caps offer the utility some incentive to reduce its costs, because it would keep the benefits of any cost reductions it makes within the cap. However, the benefits are not permanent because rate caps would be recalculated periodically, perhaps every five years. Any improvements in the utility's productivity should, over time, be reflected in lower rate caps or smaller increases.

Some consumer advocates are concerned that if an industry is facing declining costs over time, as the electric industry might, rate caps can provide the utilities with windfall profits. Also, rate caps provide little incentive for utilities to offer services, such as DSM or innovative customer services, that do not increase revenues.

Experience with price caps in the US electric utility industry is extremely limited and recent (Ackerman 1995). In the United Kingdom, the institution of price caps along with restructuring of that country's electric utility industry in 1990 is credited with stimulating substantial productivity improvements by the distribution utilities created as part of the restructuring (Studness 1995). However, it is difficult to determine which changes in the industry there were most responsible for the improvements. These price caps did not reduce the return on equity for the distribution utilities by as much as expected, and the ratepayers did not benefit from the productivity gains by as much as expected. Ackermann notes that price caps are common in the telephone industry.

An alternative to price caps is a revenue cap. Instead of a ceiling on revenue per kWh (price), a ceiling on the total revenues to be collected would be determined by the performance formula. This removes the disincentive for DSM programs that comes with price caps. The utility would be free to raise prices to recover the lost revenues from DSM. Customers would not have as much assurance of stable rates as under price caps, but they might be more likely to have the option of cost-effective DSM programs operated by their electricity supplier. The proposed Pacific Gas & Electric PBR would use indexed base revenue as its cap. (PG&E 1994).

A hedging option with PBR is for the PSC to determine a baseline rate of return on equity (ROE), as under its present ratemaking criteria, and then define a range of returns around it (Figure 3). If the utility's actual rate of return falls within the allowed range, the utility may keep all excess profits or absorb the deficit. If the ROE is within the shared ranges then prices would be adjusted to share the excess or deficit between customers and utility shareholders according to a pre-defined formula. If the actual rate of return falls outside these ranges then a new rate-making case would occur to reset the baseline. This profit-sharing option protects the utility from disastrous losses at the expense of foregoing potential profits. It also provides incentives for the utility to reduce its costs while sharing some of the savings with the customer. This type of adjustment formula was proposed in the Pacific Gas & Electric PBR proposal (PG&E 1994).

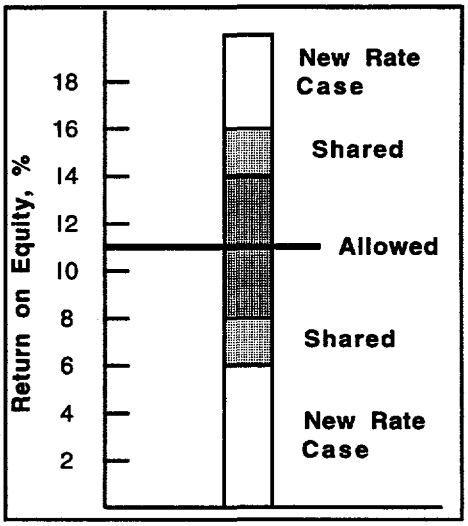

Figure 3. Possible ROE adjustment for PBR.

Ackerman notes that there is a tradeoff between reducing costs for customers during the next several years and doing so over a longer period of time. If cost savings accrue to customers in the short term, the utility may have less incentive to undertake measures in the short term that produce savings in the long term. For this reason, he suggests that the productivity element of a price cap be recalculated when the cap is reset every few years.

Performance-based rates entail some risk to customers. It is possible under some forms of PBR for a utility to best meet its targeted rate of return or rate cap by reducing the quality of service it provides, especially by reducing service reliability. The PSC can avoid this in three ways: setting service standards as part of the performance criteria; levying fines for violating the standard; or canceling the PBR program. Similarly, additional flexibility may give the utility incentives to "game" the process of ratemaking or price capping, or its decisions under them, to increase its profits in ways not anticipated when the PBR is instituted. Profit-sharing clauses in the PBR formulas may limit the utility's profits or losses, thereby lessening the incentives for performance and the long-term benefits to the customer. Finally, the customer would still be purchasing from its local utility. If the utility has inherent cost disadvantages compared to other providers, the customer may still have higher bills than it might under some other forms of utility industry restructuring or pricing.

Customers with little negotiating leverage will benefit from limits on how much the utility can increase their prices to compensate for lower rates negotiated with other customers. Customers also should benefit from a reduction in the frequency of ratemaking cases and their associated costs. A price cap probably would make it less attractive for a utility to offer auxiliary services, such as DSM, that do not increase revenues, unless it also anticipated a need to shift from low-cost to high-cost supplies during the life of the cap (e.g., because of expected changes in fuel prices). A revenue cap (instead of price cap) does not work against DSM because prices can rise to recapture lost revenue. Setting a range for the utility's rate of return would lessen but still provide some incentives for reducing costs while lowering the risk of large losses and protecting the customer from monopoly-like profits.

As with cost-based pricing, performance-based pricing is most compatible with the existing utility industry structure. PBR is more compatible with negotiated terms of service between a utility and its customers, because it can allow the utility greater flexibility in its negotiations. From the perspective of the customer interested in negotiating more favorable terms of service with the utility, rate caps give the utility greater flexibility to negotiate than present cost-based pricing, but less flexibility than the customer or the utility might want. Under a rate cap, those customers that negotiate early during the duration of a rate cap may be able to win more favorable terms than those who negotiate later. On the other hand, if the cap is reset at predetermined intervals, it may be more difficult for customers to negotiate long-term contracts than it is under the presently evolving system in which PSCs approve negotiated contracts on a case-by-case basis. PBR could be compatible with customer purchase of T&D services from a distribution utility and generation from a poolco or another utility. In this case, PBR might apply primarily to the costs of the T&D services. But where only wholesale electricity competition exists, PBR might be structured to reward a distribution company that is more successful in purchasing from lower-cost suppliers.

TIME-OF-USE PRICING

Because the demand for electricity varies in daily, weekly, and seasonal cycles, different equipment with different costs are used to meet it. It is typical for most customers to pay a price for service that averages these costs over a year or longer. Customers can be charged prices that vary with the time of electricity use, to reflect these temporal variations in the cost of service. Many utilities have a rate schedule that sets higher prices—usually for larger customers—during seasons of peak demand. Some utilities also have rate schedules that specify different prices for consumption during different periods of a day, to more closely approximate the utility's cost of providing service than the average rate.

The prices set in this manner are rough approximations of the actual cost of service. These prices can be set in advance for specific time periods and published. The actual production cost may differ from the published rate if the demand during a period is greater or less than the value used to estimate the cost of service, or if the equipment used differs from what was expected when the price schedule was established. Because these price schedules typically vary the price only over a few different periods, the price charged during the period is an average of actual costs expected by the utility during each period. This practice is termed "static" TOU pricing.

As the technology for metering service has improved and become less expensive, it has become increasingly possible for utilities to estimate the cost of providing service during a short period of time such as the next half hour; transmit this information to customers; bill the customers for service delivered during that interval; and repeat the process for the next period. Communication can occur via automatic transmission of prices to customers over phone lines or radio, via electronic bulletin boards, or simply publication in the local newspaper. More advanced systems communicate using radio signaling, powerline carriers, or fiber-optic or coaxial cable systems (Newcomb and Byrne 1995). A utility may choose the increments of time that prices are set, from changing them in real time, to changing them every half-hour, to changing them every several hours. A utility also may choose the lead time that it uses to inform customers of its estimate of the price it plans to charge based on its expected demands and production sources. "Dynamic"

TOU rates, also called real-time pricing (RTP), such as these are not widely used yet, because of the added complexity of transmitting the price information to customers, but its use is expected to increase (Newcomb and Byrne 1995).

In theory, because real-time prices are better synchronized to the economically efficient price of marginal cost, some customers may reduce their use of electricity during periods of high electricity prices and increase their use during low-cost periods. These customers would see lower overall costs. However, not all customers will have this flexibility, and some will not want to exercise it, so RTP could increase the cost of service for some customers. In addition, great variations in price are possible, which could make planning more difficult for the customer. As the utility lowers the risk of price volatility to the customer through advance notice or caps, it takes on an increased share of the risk of price/cost mismatch. Even so, it bears less of this risk with RTP than with the other pricing methods.

RTP uses price signals to provide a strong load management tool for the utility, but it requires extra resources from the utility to meter energy use by time of day and communicate more information between itself, the meter, and the customer; although this cost normally is less than what the utility and its customers would save by performing these activities, the cost does need to be recovered from the prices charged to customers. Meters that can record time of use typically are more expensive than regular meters. Georgia Power reports the cost of equipment and installation for its dynamic pricing system to be $5,000-$10,000 per customer, plus annual service and maintenance charges (Newcomb and Byrne 1995). Newer, smaller scale systems offer much lower costs. The "Powerview" residential load control technology has costs of around $800 per individual unit, but new versions allow units to be shared by up to four households (DS Report 1995). If utilities use the excess communications capacity to provide other information products (telephony, cable TV, computer on-line services) the synergies may lower the cost of providing RTP rates. Many utilities have signed agreements or are in discussions with telephone or cable companies to explore joint projects. The California PUC's majority proposal (CPUC 1995b) calls for utilities to install TOU meters for all retail customers within six years after implementation of the proposal.

RTP does not offer as many benefits to relatively inelastic demands such as residential use, where convenience and comfort may have greater value than they do to price-sensitive customers. For all of these reasons, utilities now tend to offer RTP rates only to larger users; for example Gulf States Utilities and the Tennessee Valley Authority offer RTP only to industrial customers with at least 5 MW of demand, while Connecticut Light & Power, Georgia

Power, and Virginia Power offer the option only to customers having 0.2 to 0.5 MW of demand (Newcomb and Byrne 1995). As technology improves and the costs of such meters decrease, more customers should be able to take advantage of them.

For customers who can easily schedule and shift electricity demand from one time to another, curtail some demand at peak periods without disrupting other activities, or self-generate to meet some of their demand, TOU rates can greatly lower their bills. However, Newcomb and Byrne (1995) note that for all but a few customers—mostly large industrials—RTP rates offer few direct advantages. They note that in the United Kingdom and New Zealand, where RTP has been introduced on a wide scale through restructuring into poolcos, most customers have elected to secure CFDs or other forms of insurance to insulate themselves from risks of fluctuations in the price of electricity. Even among the customers that have made the greatest responses to RTP rates, few have done so using automated control and response technology. However, Newcomb and Byrne also expect that technology for communicating price information and automatically responding to it will improve, allowing customer response to changes in price to occur automatically without disruption in comfort or service and without placing an information burden on the customer. They see great potential for these technologies to benefit commercial users, as automated control equipment becomes available to help building operators to automatically charge thermal storage devices in anticipation of peak price periods, and reduce nonessential uses during peak price periods, while maintaining high levels of service to building users. However, they see several institutional barriers to realizing this potential. These barriers include the small amount spent on electricity services compared to other portions of the business, and the separation of decisions about electricity infrastructure—made by the building owner—from decisions about electricity use made by the tenant.

NEGOTIATED PRICES

Historically, the principal terms of service available for negotiation between a customer and its utility have involved price and interruptibility of service, with a utility offering large customers lower prices in return for the option of interrupting service for short periods of time if necessary. In a number of states, large industrial customers are beginning to negotiate and contract for terms of service that are different from standard industrial rates, and it seems likely that this option will become more widely available. In addition, several states have either granted or at some level are considering granting authority to some of their public agencies to let them negotiate more favorable terms of electricity service. In some cases this authority would allow them to engage in retail wheeling. Examples include the state government in

Texas; school districts on Long Island, New York; the airport and public transit authorities in Boston, Massachusetts; and two public universities in Missouri and Utah (EEI 1994), all of which are seeking alternatives to their present electricity suppliers. In most of these cases, as with the large industrial users, reducing the price paid for electricity seems to be a major motivation.

In an example noted earlier, the "Big 3" automakers recently negotiated contracts with Detroit Edison that made Detroit Edison their sole supplier through 2000 and allow limited reductions in their purchases from the utility for 5 years afterward (Michigan PSC 1995). These customers have self-generation capacity now, and under Michigan's retail wheeling experiment they also have prospects for contracting with other electricity suppliers in the future. The latter prospects probably will not be effectively available until 2000 under restrictions the PSC placed on that experiment (IRP Report 1995). The customers agreed to forego use of their self-generation options during the period of the contract. The utility agreed to compensate them for the capacity they were not using, and it offered a reduction in rates estimated at 10-15% from previous standard industrial rates. The new contracts and the standard terms of service were for a mix of firm and interruptible power. However, under the new contract, a customer with multiple facilities can choose how any interruption in service is to be allocated across its facilities; a requirement for a 15% reduction could be met by idling one facility that accounts for 15% of the customer's load rather than having to cut back 15% at each facility. This arrangement in effect allows each customer to self-wheel service outages (but not electricity, because they will not be generating while the contract is in force). In addition, if a customer's demand increases or decreases during the life of the contract, the customer is permitted to determine whether the change will be treated as interruptible or firm load.

If Michigan's retail wheeling experiment had been fully operational when the contracts were negotiated, these customers presumably would have had additional supply options from outside the utility and their own resources, and they might well have negotiated a different contract with Detroit Edison. Some of the features of the recent contracts, such as the allocation of service interruptions, are particularly valuable for multi-plant customers and might not be considered at all in negotiations by a single plant firm, which might be more interested on negotiating terms to limit interruptions.

When one of the parties to negotiations over electricity price is a utility that serves other customers, it is possible that the utility may agree to a contract that covers its marginal cost of production but not all of the fixed costs allocated to that production. It may agree to this because it might be even worse off by losing the customer entirely. When a utility negotiates such a contract, either the shareholders or its other ratepayers could bear the burden, and the allocation of these costs remains to be resolved. For this reason, under the present industry structure, most negotiated rates are still subject to approval by PSCs. The Michigan PSC approved the Detroit Edison-"Big 3" contracts as a special case. Other negotiated contracts focusing on electricity prices have been approved on a case-by-case basis in Arizona, Indiana, Michigan, Vermont, and Washington, and they have been proposed in other cases in Indiana and Wisconsin (EEI 1994). In approving these contracts PSCs have tended to emphasize that these are special cases. However, the New York PSC has adopted a policy that allows utilities to offer flexibly negotiated rates to customers who have realistic alternatives to continued service by the utility (EEI 1994), and other states (including Arizona, and Illinois) are taking similar steps (Cross 1995). It seems likely that other states will allow similar flexibility.

In the Detroit Edison-"Big 3" contracts, several interested parties expressed concern that the contracts would earn the utility less than the cost of providing service under the contracts. The PSC acknowledged the concern about the possible revenue shortfall and how it might be paid. The PSC did not rule on this at the time it approved the contracts, but it indicated that it thought the shareholders rather than other customer classes should bear any financial burden of the contracts. On the other hand, the New York PSC's policy that allows flexibly negotiated rates would allocate 70-80% of lost revenues to other ratepayers and the rest to shareholders. The Ohio PUC has divided the lost revenues 50%-50% between the two groups, and the Montana PSC also has ordered the two groups to share revenue shortfalls from industrial retention discount rates (Carlson and Sipe 1995); other states have assigned such losses either to the shareholders or to other ratepayers (Cross 1995). Some of these allocations, such as that in Ohio, appear to have been made on a case-by-case basis rather than established as general policy as in New York. In several of these cases, the PSC has granted approval for the rate subject to review at subsequent requests for rate increases for residential or other customer classes.

Thus, although small customers are unlikely to engage in negotiation for different terms of service for themselves, there is potential for them to pay higher prices for service to make up costs incurred by serving other customers who do negotiate. Concern about this issue is likely to influence the way in which the electric utility industry is restructured, and thus the options made available to retail customers. However, it remains unclear how the issue will be resolved.

As new technology has allowed greater flexibility in TOU pricing, this pricing option has begun to be an element in negotiations. Georgia Power credits its ability to offer RTP to new industrial customers for part of its success in competing with utilities in other states and with other electricity suppliers in Georgia.

Although the benefits for the customer of negotiated service—lower prices and service that better matches its needs—are obvious, they depend on how well the customer understands its own needs and options, and on how much flexibility the utility can offer (either under continued regulation or under competitive market conditions). These benefits will also depend in part upon the bargaining positions of the customer and supplier, which in turn will be influenced by the course of utility industry restructuring. If utility restructuring takes the form of a mandatory wholesale poolco, then the scope for negotiating prices and other terms of service is likely to be diminished. Although some customers may negotiate CFDs with specific suppliers, these negotiations may be much simpler than those that occur between a customer and an established utility. Some observers believe CFDs may become instruments to be traded to reduce risk of price volatility, rather than what customers outside of financial markets typically consider to be a contract.

Small customers are less likely to negotiate prices or participate directly in markets for CFDs or other similar instruments. The transaction costs (negotiating time and effort) are likely to exceed any benefit to the small customer. To the extent that real retail competition does develop for the residential and small commercial customer markets, as discussed in Chapter 3, small customers may have a larger number of service options and prices from which to choose.

CONCLUSIONS

Electricity customers are beginning to have additional options for obtaining energy services, for purchasing them, and for paying for them. Some of these options seem likely to be transitional. They are attractive options under the present electric utility structure, and they may stimulate change in that structure, but they entail risks to the customer if the industry changes. This is because they respond to present conditions—such as large differences in electricity prices from different suppliers—that may diminish in a restructured industry. In this category we would include municipalization when it is prompted by the desire to reduce the price paid by large users; customer construction and operation of transmission lines; relocation; and possibly self-generation and long-term contracts with suppliers. For the last two options, this conclusion depends upon how the electric utility industry is restructured. The self-generation option may be more viable if the customer has need for heat as well as electricity and is willing to use cogeneration to supply both.

Depending on how restructuring is achieved and its effect on customers, other options will be more or less available and widely used on a permanent basis. Municipalization prompted by the desire to reduce prices for small customers may become more common in a restructured industry, as a way of ensuring that these customers share the benefits of restructuring. However, if restructuring occurs in ways that promote active retail competition for these customers, municipalization might be less appealing. Brokers seem likely to become more common unless restructuring takes the form of mandatory wholesale poolcos, in which case the services of brokers probably would be less valuable than with a restructuring—poolco or otherwise—that relies on greater use of contracting.

Mandatory wholesale poolcos, PBR, and bilateral contracts (other than CFDs) in their basic forms appear to be largely incompatible with each other for generation services, although some elements of each could co-exist under some forms of restructuring. Thus a customer is unlikely to be offered a choice among them once restructuring has happened. However, the components of electrical service that remain regulated (e.g., T&D) are likely to be priced separately using CBR or PBR, regardless of the purchase methods for generation.

Some options appear robust. That is, they seem likely to become more common regardless of how restructuring is accomplished. Increased competition among energy carriers (gas versus electric) and RTP pricing appear likely to increase in any event.

From the perspective of the customer, the various options differ primarily along four dimensions: price, transaction costs, ability to accommodate customer preferences, and potential for regret if conditions change and alternatives are available (Table 2). By accommodation, we mean the extent to which a customer who uses an option can obtain electricity service tailored to its specific needs not just for quantity but also for convenience, quality, and management of risk when these are importance attributes of service. By potential for regret, we mean the potential for a customer who has adopted an option to regret it if conditions change, either because the option was incurred at high cost or because in order to obtain it the customer had to agree to a long-term contract or some other measure that restricts its subsequent freedom of action.

Table 2. Relative values of retail electric customer options with regard to price, transaction cost, accommodation of customer desires, and potential for regret

	Price of Service	Transaction Cost	Accommodation	Potential for Regret
Procurement Options				
Self-generation	low – medium	high	low	medium – high
Self-service wheeling	low – medium	high	low – medium	medium – high
Alternate energy carriers	low	medium – high	medium – high	low – high
DSM or energy services	low – high	medium	medium – high	low – medium
Relocation	low – medium	high	medium – high	high
Purchase	low – high	low – high	low – high	low – high
Purchase Options				
Local utility	low – high	low	low – medium	low – high
Municipalization	medium	high	low – medium	medium – high
Bilateral contracts	low – medium	medium	medium – high	low – high
Broker	low – medium	low – medium	high	medium
Poolco (wholesale)	low – medium	low	low – medium	low – medium
Customer-owned	medium	high	low	high
Pricing Options				
Cost-based	low – high	low	low	low
Performance-based	medium	low	low	low
Time-of-use	low – medium	medium – high	low – medium	low – medium
Negotiated	low – medium	high	high	low

The rankings of low, medium, and high are necessarily subjective and speculative at this point. They attempt to portray the trade-offs that a customer would face when selecting between options. Individual customers may see different rankings depending on their particular situations.

This report has identified some of the qualitative differences among the various options on these dimensions. It has also noted that some of the options—and much of the debate by economists and other policy analysts over how to restructure the industry—are likely to be indistinguishable from each other at the retail level, except for the price of service. This result seems more likely for small customers than for large ones, who have greater resources with which to bear the costs of evaluating, choosing, and negotiating alternative terms of service from among a broader array of options.

In subsequent research, we plan to quantify to some extent the effects on customers of some of the options explored in this paper. At the same time, it should be possible to explore the resultant effects on other customers of the utility and the utility itself, if certain customers are allowed to exercise the options. What happens to residential prices if industrial customers are allowed to purchase on the wholesale market or through negotiated rates? How much do performance based rates alter the prices paid? What type of rates would customers pay for T&D services alone? This research will help identify which issues are likely to have large effects on retail prices, and which may be of less importance to the retail customer. This analysis will use the ORFIN model (Hirst and Hadley 1994) which simulates the operation and finances of a utility over a multi-year time period, taking into account wholesale power availability, retail wheeling, economic load dispatch, T&D investments, and multiple customer classes.

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