

***FUTURE UTILITY
AND
REGULATORY STRUCTURES:***

***If you don't know where you're going,
any road will get you there.***

I. INTRODUCTION

The Energy Foundation has convened a small group of people to discuss the future of regulation in the electric utility industry. The group has met twice and has had the benefit of a number of papers written by various members of the group. Most recently, each of us was asked to write a paper outlining his views of ideal regulatory and industry structure. Each author, however, was given one additional precondition. One author, David Moskowitz, was asked to assume that retail competition, in particular, retail wheeling, was permitted. The other author, Paul Joskow, was to do the same thing but was to assume that retail wheeling did not exist.

The two papers were considered by the full group at a meeting in Chicago in December, 1993. As it turned out the alternatives we put forward were remarkably similar. So similar that the group asked us to attempt to draft a joint vision paper.

This paper represents our efforts to reach common ground on a single view of the most desirable industry and regulatory structures. Neither of us view the model we set forth as being ideal. We agree, however, that given the very imperfect conditions from which we begin and the very real practical and political constraints that always impede the creation of ideal scenarios, the model and options we present here would represent dramatic improvements over the status quo and would leave very little to be achieved through even more idealistic variations of these models.

The views we express and the options we present are aimed to meet four broad goals:

1. lower cost and more efficient supply of electricity
2. increased efficiency in the use of electricity
3. reduced environmental cost and risk of energy production and use
4. increase reliance on incentive regulation rather than command and control

Before describing the options, we first review the forces that inevitably will shape the future of this industry, including how it is regulated and the future of retail competition.

In broad terms, these forces can be broken down into four overarching influences: public interest, environmental concern, technological change and competition.

The **public interest** element recognizes the important range of public and political requirements which cannot be ignored under any utility or regulatory framework. **Environmental concerns**, as reflected by the public cry (and legislative response) for a cleaner and safer environment, will increase, not diminish. The demand to identify and act upon local, national and global environmental risks will steadily increase. Balancing environmental and energy needs will continue to challenge utility planners and developers, whether in the private or public sector.

Technological advances on the demand- and supply-side will continue to define the industry and industry decisions. Finally, the prevailing public preference for **competitive solutions** to real and perceived problems will be a major factor.

Public Interest. The public interest questions lie at the heart of the utility's obligation to serve and at the unique relationship utilities have developed in their communities. As a "first citizen," utilities are inescapably (both literally and figuratively) a part of the social fabric of their communities. Unlike other industries which have the option to leave at will, the public utility industry does not and cannot move. In this role, utilities have a self interest in being a "first citizen," and the public has come to expect them to play a central role in issues well beyond the efficient production, delivery and consumption of electricity.

As members of communities, utilities are employers, sponsors and funders of many causes and often are spokespeople for a larger business community. One could question whether this prominence is desirable, but there is no doubt that this unique position of leadership exists.

In addition, electricity itself is a unique product and plays a central role in modern society. Its tie to economic productivity and its central role in the expanding productivity and information society makes it a foundation for survival in a future world. Therefore, some form of governmental oversight will always be present.

Care must be taken to ensure that mechanisms exist for the public to communicate its expectations, particularly when value systems are undergoing the changes described below in the Environmental Concerns section. The process of public participation in regulatory decisions while continually evolving, will have a whole new face in a competitive structure. In this framework, the market place may well reduce and, for some purposes, replace the role of regulatory hearings as a vehicle for the public to communicate its expectations. But if the more competitive industry structure creates circumstances that the public cannot tolerate -- loss of universal service, unacceptable rate shock to particular customer classes, loss of consumer protection, discriminatory service, declines in the quality of service, unacceptable environmental impacts or a situation in which deregulation produces an unregulated monopoly -- the public participation process will re-shift its focus and once again rely more heavily on regulatory or legislative hearings.

To be considered successful, a competitive, electrical service industry must result in relatively stable energy supplies, energy prices and industry structure. If the lights go out, if prices fluctuate beyond what customers are already accustomed to or if the range of prices for different groups of customers is too great, political reality will likely eliminate whatever industry structure or regulatory system is perceived to have produced or exacerbated the problem.

Environmental Concerns. Energy production and consumption are inextricably linked to the environment. Electric utilities account for 69% of national sulfur dioxide emissions. Utilities account for 35%, 32% and 5% of carbon dioxide, nitrous oxide and particulate emissions respectively. For these reasons and others, utilities have always been an early focus of

environmental regulation and public attention. The focus of the next round of environmental regulation will be on tighter or new controls for:

1. nitrous oxides to address ozone non-attainment issues
2. toxic air emissions
3. the growing recognition of the health risks created by very fine particulates
4. CO₂ and other greenhouse gas emissions

Sooner or later new regulations will address each of these areas, and electric utilities will be one of the first targets. The bottom line is that electric utilities have been, and will continue to be, expected to make and implement energy decisions that offer energy services without jeopardizing environmental quality.

With increased industry competition, more energy services will be marketed across state boundaries. The burden will be on the federal government to come up with ways to equitably handle the external, environmental (and national security) costs. For instance, as of yet no federal and few state regulations exist to regulate carbon emissions. Yet, carbon is recognized as a major greenhouse gas and contributor to global warming. Probably the best way to accomplish this is to internalize these costs using some sort of carbon tax. This would substitute nationwide for the externality adders that selected states, such as New York, California and Massachusetts have adopted in the absence of federal action. Federal actions on this front would level the playing field for all competitive players. Near the end of this paper we propose a specific recommendation to move this recognized need for federal action from the drawing board to the implementation stage.

No matter how successful we are at incorporating environmental externalities into energy investments, there will always be some customers or other government entities who want to go further. Mechanisms for paying cost premiums -- beyond those costs that would be included in externality costs -- need to be designed and implemented. Tools could include direct subsidy, customer-specific pricing, such as green pricing or a requirement comparable to the British nuclear requirement.

Technology. Technological improvements in power plant construction drove electricity prices down during the thirty years from before World War II to 1960. Thermal efficiencies in electricity production improved from below 20% prior to the war to nearly 40% by 1960. Since then, material limits (i.e. metallurgical weakness at high temperatures) have restricted continued improvements in thermal efficiency. Any additional efficiency gains, therefore, have come not with traditional technologies but from new technologies.

The current generation of gas turbines¹ are already highly efficient and, in the future, may achieve efficiencies in the range of 60% (lower heating value). But the more compelling attributes of turbines and other new technologies are that they are smaller, cleaner and manufactured as opposed to constructed. Gas turbines in the range of five to 25 MW can now be ordered from factories, delivered, hooked up and placed on line in a matter of months, not years.

Turbines are also important because they provide the means for efficient utilization of other fuels, such as biomass. The first prototype, a six megawatt biomass gasification combined-cycle gas turbine, was recently commissioned in Värnamo, Sweden. A 25 MW plant is planned for Brazil's northeast state of Bahia, with the support of the Global Environment Facility.

A Pacific Gas and Electric (PG&E) study looked at the value of smaller, modular generation systems. They evaluated the use of photovoltaics (PV) in the distribution system and found that the benefits at the selected location exceeded the value of energy produced even at today's costs for PV (Only about half of the savings came from avoided bulk power. The other half came from distribution benefits like transmission and distribution savings and reliability enhancement.) PVs are not the only candidate for this type of service. Proton exchange membrane fuel cells, which may soon be commercially viable, are expanding the realm of possibility for household self-generation and retail competition. These two kW generators could be placed in the bottom of hot water heaters and serve as a miniature cogeneration plant by producing hot water and electricity. Maximizing the economics of these units will require integrating them with the grid and dispatching output to meet the needs of the customer, the local distribution plant and the system.

PG&E's evaluations suggest that the traditional approach of adding central station generation and T&D assets to meet new load may not be the most cost-effective way to provide new service in all cases. PV, small generators, customer energy efficiency and storage might be lower cost options.

Smaller sizes and modular construction means that units can be placed nearer to the customer. Locating generation near or at the point of use reduces the T&D costs normally required to deliver energy from a central generating facility. When this happens, the one-time distinct difference between a distribution station and the sources of power becomes increasingly blurred.

Despite the fact that utilities invest more money in the distribution system than in power plants, most of the distribution system is underused and sits idle most of the time. The timing of peak demands on the distribution system vary significantly from the timing of peak demands on the system as a whole. This means that the central dispatch of bulk power from a power pool has

⁰These turbines have developed not as an offshoot of conventional power plants but as an offshoot of aircraft jet engine design.

little relevance in meeting distribution feeder peaks. Meeting the energy needs for these more localized peaks may be accomplished better by dispersed, small, modular technologies that can supply power at crucial points in the distribution system.

Many of these emerging technologies achieve their cost efficiencies through economies of mass production. Greater efficiency and lower cost is achieved by manufacturing more wind machines, solar photovoltaics or high efficiency compact fluorescent lamps rather than through massive on-site construction which was the key to achieving generation efficiencies in the past. Small unit size and very short lead times also mean the time and financial commitment to bring new low-cost technologies to the market is very short.² This shift from constructed to manufactured energy has profound implications for how we think about the industry and the regulatory structure that oversees it as well as how fast changes will come.

Energy efficiency technologies and smarter packaging and applications of existing technologies are being demonstrated. One of the best examples is PG&E's ACT² program that is designed to show what best practices can achieve. A recently completed house in Davis, California is achieving a 70% reduction in energy use over new homes meeting California's energy efficiency standards. The house cost \$3,000 less to build than a conventional house.

Competition. We need to recognize and address what lead some retail customers to demand that they be given the opportunity to purchase their generation requirements from competing electricity suppliers, relying on the local utility only for wheeling and various residual services. We also must recognize that retail wheeling is only one of a whole menu of competitive options that retail customers have now or may have in the future. This menu includes self-generation and cogeneration, municipalizations of various kinds, fuel switching and shifting production to facilities in other parts of the country or the world. Removing retail wheeling from the menu does not relieve us of the task of taking other types of retail competition into account in our analysis.

For much of the period from roughly 1930 until the early 1980s it was more economical for most customers to opt to be in the system -- that is to take electricity exclusively from a single regulated utility -- than to opt permanently for the opportunity to shop around among competing utility suppliers or to self-generate. Indeed, many of the largest industrial customers gradually and voluntarily shifted from supplying their own generation (self-generation) to entering into long-term contracts with a proximate utility to take advantage of the lower costs and superior reliability provided by integrated central station generation (in 1920 roughly 50% of industrial load was provided by non-utility generators). Although these contracts eventually evolved into tariffs (sometimes serving only one or two customers), historically the largest customers' decisions to affiliate with a particular utility was made in an environment in which they had choices. Thus, these customers were not forced to be in the system, but chose to become a part of

²For an example of the dramatic impact small size and short lead times see *The Direct Economic Benefits of Accelerated Development of Renewable Energy Technologies, A Case Study of Photovoltaic Power*, by Robert H. Williams and Gregory A. Terzian, Center for Energy and Environmental Studies, Princeton University, Princeton, NJ 09544, 1993.

it because it yielded a more attractive mix of price and quality than the alternatives.

Until relatively recently, it was not in the interest of most customers to sever their relationship with their local utility and fend for themselves in the cruel world of competitive power markets. Yes, temporary mismatches between prices and market values emerged from time to time and opportunities to make money by buying from a competing supplier for a period of time and then returning to the local utility for the shelter of price regulation and service obligations appeared.³ The benefits of such strategies were relatively small and, as a result, the incentive to expend significant resources to create such competitive opportunities were small as well. The situation has changed in recent years. More and more large customers are willing to forgo permanently the shelter of regulation for a fully competitive system (or so they say).

The motivation today for customer efforts to avail themselves of the opportunity to turn once again to competitive alternatives, whether it's retail wheeling or one of the other competitive options on the list, is obvious. These customers think that they can get electricity at a much lower price over the long run if they can access a competitive market than if they continue to rely on their local utility for bundled service at regulated rates. I feel very strongly that a system that forces a large fraction of customers (measured by sales volume rather than numbers of customers) to pay significantly more by restricting the competitive choices available to them than they would pay without these restrictions cannot be sustained in the long run (recognizing that the long run can be a very long time indeed).

This leads us to conclude that any reform scenario must ask whether we have created a system that has attributes that are sufficiently attractive to the vast majority of customers that they would prefer to be part of it because it offers them the most attractive price/quality (broadly defined) package or whether the system is such that a significant fraction of the customers would rather rely on an unregulated competitive market but are forced to stay in the regulated monopoly system by legal fiat.

It is also important to understand why there is a gap between what it costs customers who continue to buy from their local utility at regulated rates compared to what it would cost if they could turn to a fully competitive system. It is convenient to divide the sources of this gap into three categories⁴:

1. Inefficiencies associated with the institution of regulated vertically integrated electricity monopoly

³This kind of situation also led utilities to argue that if certain retail customers left to get better temporary deals elsewhere they should not be allowed to come back on an embedded-cost rate, but only on a market-determined rate. Few utilities today would decline to serve any customer on their standard tariffs.

⁴It is not so easy to separate these components of the gap in practice. Some would argue that if we had a more competitive system we would not have made some of the decisions that turned out to be costly mistakes *ex post*.

2. Sunk costs that exceed current market values which reflect "good" investments decisions made in the past that turned out to be uneconomical as market conditions changed over time
3. The impact on prices on items such as DSM, excessive consideration of environmental externalities, low income programs⁵

For the average utility our guess is that the bulk of the gap is associated with sunk costs that are now uneconomical, a smaller fraction associated with social obligations (including differential state and local taxation of utility property and sales), and an even smaller fraction associated with true economic inefficiencies.⁶

In principle, regulatory reform can reduce the size of the gap by ameliorating the portion that is attributable to inefficiencies created by prevailing institutional arrangements. Public policy can also, in principle, remove the cost asymmetries associated with costly social obligations that are imposed on utilities and which individual customers (as electricity customers, but not necessarily as citizens) would choose to avoid if they could. *There is nothing we can do to make sunk costs go away, however. All we can do is to decide who is going to pay for them over what time period.*⁷ If it turns out that the primary motivation for retail wheeling is to avoid paying a share of these sunk costs, and if we are correct that they represent a large fraction of the rate gap, then we should not be under the illusion that regulatory reform is going to make the problem go away.

II. OVERVIEW OF RECOMMENDATIONS

To this point, we have described the forces and conditions acting upon the electric utility industry. The rest of the paper treats these forces as a given. We turn our attention now to proposing industry and regulatory reforms.

In addition, our collective experience leads us to adopt a few basic principles upon which to shape our discussion. We describe them briefly to serve as points of departure for this paper and not as areas which require further elaboration since it is assumed that they are already well

⁵As a practical matter, we are talking only about investor-owned utilities since municipal utilities and state and federal power authorities are generally not subject to the same regulatory or tax obligations.

⁶This does not mean that the potential efficiency gains are not economically significant in absolute terms. If we could lower average electricity rates by only 5% by increasing efficiency this would be a very significant achievement with a present value of roughly \$70 billion.

⁷This is not to say that whether and how these sunk costs are recovered have no efficiency implications. An efficient market economy depends on credible institutional arrangements that require individuals and governments to live up to their financial commitments.

understood by the reader.

These principles can be summarized as follows:

1. Prices, and hence resource decisions, should reflect the total long- run cost of an energy resource, including external environmental costs.⁸
2. DSM or energy efficiency is cost effective and desirable whenever the total costs of saving a kW or kWh is less than the cost of supplying power. While customers responding to accurate prices has been and will continue to be the primary driver of increased energy efficiency there remains a very important role for electric utilities.⁹
3. A key test of a successful new structure is whether it creates financial incentives for the electric industry to help the country reach least-cost solutions to its energy needs. Unless the utility has a financial interest in energy efficiency and renewable resources, these resource options will not make up a meaningful portion of its investment strategy.
4. IRP is best thought of as a set of planning principles that are useful in identifying cost-effective resources. IRP principles should not be confused with a particular IRP regulatory process. IRP regulation can be implemented in a "light-handed" fashion, a "heavy-handed" fashion or anywhere in between. Because the options we present assure that the utility benefits financially through its own implementation of an IRP process, our options rely on systems of "light-handed" regulation. This is done because the more

⁸See discussion at page _____ which described our agreement on what these costs are and how to go about estimating their size.

⁹The critical distinction between electricity prices and electricity costs must be recognized. First, the impact of DSM on utility prices is largely indifferent to who pays for DSM. If we magically removed all DSM market barriers, and customers invested in DSM, electricity prices would increase. Magic wands, hence, fail the rate impact test. Second, the lower the cost of electricity-per-dollar, the more competitive the industry. There are two equally effective ways to reduce the cost of electricity- (or more broadly speaking, energy) per-unit output in order to become more competitive. One can decrease the price of electricity or increase the efficiency of electricity use. Experience shows that increasing the efficiency of electricity use yields larger cost savings and is easier to achieve than most efforts to reduce prices. While increased application of cost-effective energy options will always decrease energy and electricity costs to the customer, it may or may not have the same effect of decreasing average electricity prices or rates. Despite the possibility of adverse, but small, impacts on average prices, it is important to remember that competitiveness is driven primarily by cost, not price. Even this small impact on average price can be addressed through thoughtful rate designs and possibly some energy service charges.

traditional command and control mechanisms are slower to respond to changing conditions, they are more expensive to implement, and they are at best only partially effective.

5. Competition, in both wholesale and retail markets, can be a very effective way of reducing costs.

III. OPTIONS FOR BUILDING RETAIL COMPETITION INTO THE UTILITY INDUSTRY

Retail rates in an ideal world

We begin our discussion of regulatory reform with a review of retail price setting in an ideal world. Understanding our views of this subject will prepare the reader for our proposed regulatory reforms and our approach to retail wheeling.

The utility has a lump of costs (sunk costs, operating costs, incentive payments less penalties, costs of social obligations, etc.) that it has a legal right to recover from its customers. The basic economic principles are clear. Retail rates should be designed to achieve two goals. First, they should provide good price signals to consumers so that they can make wise (efficient) decisions about how they use electricity. Second, they should also yield enough revenues to recover the utility's costs.

In theory, the most efficient price is a price that is equal to the relevant marginal cost of providing service. Unfortunately, marginal cost pricing rarely yields the appropriate level of revenues to recover total cost (we get either too much or too little revenue). So, we must depart from pure marginal cost pricing. This should not trouble us too much since prices are rarely equal to marginal cost in most "competitive" markets either. In the cases of interest to us here, the relevant marginal costs (properly calculated) are far below average total cost, at least in the short run, and perhaps in the long run as well.

Economists say that the ideal way to design utility rates to achieve these goals is to rely on two-part tariffs (or more generally on non-linear tariffs) that have the following general form:

$$\text{Bill for Customer } i = f_i + c_i * (\text{quantity consumed by customer } i)$$

We build up the retail rates by first setting usage (per unit of consumption) prices equal to the relevant marginal cost (c_i). The marginal cost may vary across customers based on their load characteristics and can be broken up into separate components to reflect differences in marginal cost by time of day or season (or even in real time). Residual revenue requirements are then recovered through hook-up or customer charges (f_i) that do not vary directly with customer

use.¹⁰ These charges too would vary across customers. The hook-up or customer charges must be set high enough so that the tariffs produce adequate revenues and so that customers do not have an incentive to leave the system completely (e.g. via self-generation) as long as they are willing to pay at least the marginal cost of serving them.

Unfortunately, there may not exist a set of hook-up or customer charges that satisfy these criteria, or the sets that do satisfy these criteria may conflict with other equity considerations.

These basic principles lead to a number of suggestions for regulatory reforms in the area of retail rates and backup rates:

1. Retail ratemaking should distinguish more clearly between marginal costs (or avoidable costs) and fixed, common or joint costs. Rate designs should give consumers powerful incentives to avoid paying for the former (e.g. through energy conservation or cogeneration) when competitive alternatives can beat the utility's marginal cost but not to avoid paying for the latter. When customers have competitive options (whether it is cogeneration, or fuel switching, or retail wheeling) utilities need the flexibility to price all the way down to the relevant marginal cost (but not below). A customer should never be lost to a competing alternative unless the competing alternative has a cost that can beat the utility's marginal cost. In many parts of the country, given today's cost structures, these principles mean more costs should ideally be assigned to the customer charges or initial blocks of declining block tariffs and much less should be allocated to the tail blocks.
2. Backup service and partial requirements rates need to be adjusted to reflect the residual fixed and/or joint costs that need to be collected by the utility. Existing backup rates have been set in a very sloppy way. Not only don't they reflect an equivalent contribution to the fixed or joint costs of the system (f_i) they often do not even reflect the true incremental cost of providing backup generation, reserves, and transmission service. Backup and partial requirements rates should include the same f_i as would the equivalent retail rate for a customer with equivalent load characteristics.

Unfortunately, the types of retail rates we suggest may be very difficult to adopt. First, it can be difficult to calculate the relevant marginal cost unambiguously and these costs change over time. Changing prices dramatically and rapidly and may not be practical or politically acceptable.

Moreover, the precise distribution of the hook-up charges f_i has important equity implications reflecting both income distributional considerations and the fact that investments in capacity that has turned out to be excess was made to serve the expected needs of all customers. As a practical

¹⁰They could be based on historical utilization patterns, however.

matter it may be impossible to adjust rates quickly enough or to slice tariffs finely enough to responding to changing market conditions particularly to residential and commercial customers. It may be practical however to move back to a regime in which large customers are served on contracts with notice provisions and minimum take provisions, combined with approximations to the ideal tariff design discussed above.

Notwithstanding the practical and political difficulties in adopting these types of rate designs they provide a useful insight to our transition to regulatory reforms. Consider what the utility's revenue stream would look like if these ideal rate designs were put into place. At the extreme, one would have very large customer charges and energy consumption would be billed at short-run marginal cost. Residential customers would have a relatively low customer charge while commercial and industrial customers would have increasingly higher and higher customer charges. Energy prices would be the same for all of these customers with the exception of minor adjustments to reflect line losses at differing voltage levels. The utility's revenue stream would thus be a fixed level of revenue-per-customer plus variable operating costs associated with the energy actually supplied to consumers.

Even though it may be impossible to design and implement retail prices that produce this revenue stream, it is possible to construct a system of regulation that closely parallels the impact that these prices would have on a utility's revenue stream.

With this background we present three primary options and one variation for consideration. These are:

1. Revenue-Per-Customer Regulation, Auctioning of Service Franchise
- 2A. Retail Wheeling Framework, Anyone Supplies Kilowatt Hours
3. Emission Taxes, Substitute for Income Taxes¹¹

OPTION 1

Revenue-Per-Customer Regulation, Auctioning of Service Franchise

The first option describes a form of revenue regulation applied to a regulated utility providing monopoly service in a geographically defined service franchise area. Under this option, there is no retail wheeling per se although, as we describe, there are other forms of retail competition.

Power supplies are purchased by the utility from the deregulated, competitive supply market or are constructed by the utility.

⁰ This final option is included not because of its direct application to retail competition but because it improves the other options by internalizing environmental costs.

This option moves from traditional systems where revenue and hence fixed cost recovery is entirely dependent on sales to a structure where revenue is instead based upon the number of customers served. This change provides a revenue stream similar to that produced by the ideal prices structures described earlier and also assures that energy efficiency is compatible with the utility's own financial interest. There is recent precedent in a growing number of states in the United States for this approach.¹²

This option can be explained using the following equation.

$$\text{ATR} = [(\text{RPC} * \text{X}) +/- (\text{Delta UPC} * \text{System Lambda})] * \text{Customers} + \text{DSM}$$

where

ATR Allowed total revenues that the distribution utility will ultimately be permitted to collect from customers, including all power supply, historic DSM costs, transmission, distribution and other costs. A surcharge/rebate mechanism adjusts prices to even up the discrepancy.

RPC Average revenue-per-customer. This amount is determined periodically by the regulators.

X Productivity factor to allow RPC to vary with time.

Delta UPC Change in average use-per-customer.

System Lambda This term is included to prevent large earning swings due to weather and other short-term impacts on sales.

DSM A term to allow recovery of prospective DSM costs. There are several options here:

- A. The utility could be allowed recovery of actual costs. This approach, which is in the best interest of the utility, requires

⁰ This approach first appeared in *Profits and Progress Through Least-Cost Planning* by David Moskowitz. Subsequent articles are *Decoupling Sales and Profits: An Incentive Approach That Works* by David Moskowitz and Gary Swofford in the July 1991 issue of the Electricity Journal and Chapter 4 "Revenue-per-Customer Decoupling" in *Regulatory Incentives for Demand-side Management* by Nadel, Reid and Wolcott, ACEEE 1992. This form of regulation has been in place in Maine and Washington for several years and in the U.K. as of July, 1993. The approach is proposed in Montana, Washington D.C., Kentucky, Florida and California.

some form of administrative/ regulatory review to ensure that the costs are reasonable.

- B. Cost recovery could be based on fixed recovery level. For example, the utility would be allowed two cents per kilowatt-hour for each kWh saved through lighting programs. Similar recovery levels could be specified for other programs such as service packages offered by the utility.
- C. Recovery could be linked to the costs of acquiring supply-side resources. Examples might include allowing the utility to recover 100% or some lesser fraction of the expected marginal cost of supply-side resources.

Customers Number of customers

The mechanics of the RPC approach starts with the same cost-of-service process that takes place under any price-setting regime. The only difference is that the same data that is used to establish the utility's prices is also used to establish the average RPC. This average RPC is calculated by dividing allowed revenues by the average-test-year customer count. The resulting allowed RPC figure remains fixed until the next time prices would normally be reviewed.¹³

The RPC, while calculated, plays no direct role in setting charges for individual customer service. Customers are billed for service using any combination of pricing elements including customer, energy and demand charges. By doing this, larger and small users contribute their fair portion to the total revenues.

During the billing year, two key numbers are tracked and then compared on an annual basis. These are actual revenues (the dollars the utility collected from customer) and the allowed revenues (the previously set RPC times the actual number of customers served by the utility). At the end of each year, any disparity between the allowed revenues and the actual revenues is corrected as either a surcharge or refund to rates during the following year.

The administrative or regulatory process necessary to complete this task is remarkably simple, mostly because costs are not reviewed.¹⁴ The review is limited to comparing two readily

⁰In states where this approach is now in place, the average RPC is based on an aggregate customer count which includes all classes of customers: residential, commercial and industrial. Regulators in the states of Maine and Washington considered setting separate RPC levels for each customer class and concluded that, while it could be done, the undertaking was unnecessary because the final allowed-revenue figure did not change substantially. Similar proposals in several states are limited to residential customers.

¹⁴In Washington, the division of cost between base and resource costs was a constant source
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available, non-controversial numbers. Also, because revenues are reviewed, the utility is completely at risk for changes in costs.

This RPC approach has the flexibility to be adapted to a wide variety of utility circumstances including situations where the customer base is increasing or decreasing or the customer mix is changing. Most importantly, by decoupling profits from sales, the RPC approach removes the utility's disincentives to DSM and does so regardless of who pays for or installs the DSM (although the utility is best off if the customer pays for the DSM measures.). In addition to removing traditional disincentives to cost-effective DSM, this approach also removes the disincentives to adopting innovative rate designs that send the right long-run price signal. Better price signals can cause customers to use electricity more efficiently. In the current pricing system, this can result in significant earning and revenue losses. An RPC approach removes this disincentive because earnings and revenues are independent of customer response to new prices. This form of regulation is quite compatible with the role of the utility as a provider of energy services, not simply electricity.

Assume for example that a utility provides energy services at an average cost of \$500 per customer per year and that the average customer uses 10,000 kWhs per year. This means the average cost of a delivered kWh is five cents. In addition, we assume that three cents covers fixed costs, including fixed power supply costs, and two cents covers marginal energy cost.

In this situation, the utility has \$500 to meet the energy service needs of the customer. Its business challenge is to figure out how to do this as economically as possible. Given this scenario, how can the utility benefit financially (or at least not be harmed) by increasing energy efficiency? Assume, for example, a utility can increase the customer's energy efficiency by 10% at a cost of 50% of the supply purchase or one cent per kWh. Assume further that the utility and customer share the DSM costs evenly; both pay one-half cent per kWh.

Under traditional regulation, the utility's revenues are reduced by five cents per kWh or \$50 per year due to lower sales, its fuel costs are reduced by the two cent marginal energy cost or \$20 per year, and it takes on the DSM cost of one-half cent or \$5 per year. The bottom line is a 3.5 cent per kWh or \$35 per year reduction in net revenue and net profit.

Under our RPC option, the effect of DSM on the utility's costs is also a net 1.5 cent reduction per kWh or \$15 per year (a two cent reduction for fuel and a one-half cent increase of DSM). The utility's allowed revenue goes down by the same 1.5 cents per kWh or \$15 per year. As a result, earnings are not effected by the DSM investment. (Also, to the extent that all or part of the emission taxes, as seen in Option 3, are paid as a function of utility purchases, the utility could benefit from a lower tax bill.) If there are other less immediate cost savings, such as reduced

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of debate and confusion. The origin of this problem can be largely attributed to the fact that a fuel clause was not instituted when the plan was first implemented. The approach we recommend here overcomes this problem by eliminating the need to make the split in the first instance.

capacity costs and reduced T&D costs resulting in higher earnings, these could be retained by the utility or the formula could be modified to share the savings between the customers and the utility.

The productivity factor, X , can be used to let the allowed RPC vary over time. For example, if the utility expects to become more efficient, this factor could be periodically modified to distribute some or all of the improvements to the customers. Alternatively, if the factor were set at 1, any improvements would benefit the utility.

The scope of the revenue formula dictates the underlying incentives. In Washington, Maine and as proposed in California, power-supply costs are treated through mechanisms that resemble fuel adjustment clauses. While these mechanisms vary, their general effect is to remove or diminish the utilities incentive to manage this component of energy service costs.

Our proposed formula is much like that proposed in Montana and Oregon, two states without existing fuel adjustment clauses. The effect of including supply-side costs in the formula is to create an incentive to manage the full portfolio of resources. This approach means utilities can make or lose money on their purchased power skills. The strength of this incentive can be increased still more by using market or yardstick measures of power supply costs. The inclusion in the formula of a term for short-run marginal cost serves to insulate the utility from short-term sales patterns caused by exogenous factors such as weather or the economy.

Franchise Auctions. Under RPC regulation the utility has a powerful incentive to cut costs. Any dollar of cost saving that does not also translate into a dollar of revenue reduction means a dollar of increased profit. Still, the incentive to cut costs may be increased by adding levels of competition. Retail wheeling is how some people suggest placing utility managers under increased competitive pressure. Another approach that may be simpler, more encompassing and more powerful is to periodically put the entire utility out to bid. This would test the efficiency of the utility and could further reduce the level of regulatory oversight.

The bidding process we envision focuses the power of competition on the allowed RPC, not the price for the utility assets. RPC bidders would compete for the exclusive monopoly franchise for a set period of years. Bids would be evaluated primarily based upon who would accept the lowest allowed RPC. A preference for the current franchisee (allowing perhaps a 1%-2% higher bid) might be built into the rating system to avoid changing management and ownership without a meaningful cost saving. For the successful bidder to take title of the franchisee's plant, he must compensate the franchise holder by paying the book cost of the investment. (Under "service quality" below we offer a modified purchase price plan.) This mechanism allows market competition for the efficient delivery of energy services, either through supply- or demand-side resources.

Any winning bidder would be bound by all existing contractual requirements (labor, power-supply contracts, etc). Otherwise bidders are free to seek out cost savings in any area subject to the total revenue formula described above. (This can also include attempts to renegotiate

contracts, an option that the original franchise always has but might not use.) Cost reductions through improved power-supply contracting, more efficient delivery of DSM (including the ability to increase contributions from participants in DSM programs), savings in distribution costs and savings in overhead and administrative costs are all places where prospective bidders can target cost-saving opportunities.

The possibility of relying solely on competitive bidding, not regulation, to set the RPC depends on the length of time between bids and what would otherwise be the frequency of revisiting the RPC. On the one hand, the longer the period between resetting the RPC, the greater the incentive to cut costs and the greater the incentive to pursue long-lived DSM (and supply-side) measures. On the other hand, the longer the period between bids, the less opportunity for the market to squeeze out inefficiencies and the less practical it is to rely on the bidding process as the sole mechanism to set the correct revenue figure.

Service Quality. For this or any other option to be operational, there will need to be some way to assure that minimum service quality levels are maintained. We discuss the issue here, however, because the suggested bidding scheme provides an opportunity to rely on the market, not merely regulation, to help assure customer service is maintained.

One of the easiest but generally undesirable ways that utilities can profit from systems that reward cost cutting is to reduce costs by cutting service quality. To protect against this possibility, we could set minimum standards for items such as number and duration of outages, time to respond to service requests and complaints and overall customer satisfaction. The franchisee would then be obligated to meet these standards and an administrative agency would police compliance.

Another alternative would be to create a service quality index comprised of quantitative standards (number and duration of outages, time to respond to calls and complaints, etc.) combined with a standard survey instrument of customer satisfaction. The service quality index would then be used to adjust the required payment price for the utility's service district. For example, a high customer service rating might result in a required payment price of 110% as opposed to 100% of book value. This will give the existing franchise a competitive edge and an incentive to keep customers highly satisfied. At least one state has included this type of feature in an overall regulatory reform plan.¹⁵ If a workable index were developed, this alternative would be preferred.

Other Considerations. Auctioning the service franchise also requires other features, including the following:

⁰Rochester Gas and Electric Company in New York has a portion of its earnings tied to this type of index.

Open Books. Potential bidders will need access to detailed information on the utility's plants and costs. This is necessary both to give bidders a fair opportunity to develop a realistic bid and to inform customers of the process so they do not feel that they are being used.

Who Decides Who Wins. An entity, other than the current utility franchisee, decides who wins the competitive bid.

Qualifications for Bidders. Minimum qualifications for bidders along the lines already required for supply-side bidders will be needed.

This option can only be effective if there are a sufficient number of players so that the market for providing utility service is, in fact, competitive. If there are not enough players to compete, this approach will fail. At a minimum, however, bidders are likely to include other owners and operators of distribution companies.

This option relies on competition in the generation business and incentives to negotiate and manage power contracts to reduce production costs. This is accomplished by reliance on RPC rather than revenue-per-kilowatt-hour as the primary driver of utility earnings. Regulatory regulation leaves undisturbed the beneficial cost-cutting incentives associated with traditional regulation; the most notable being regulatory lag as a primary tool for encouraging utilities to cut costs.

The cost cutting feature could be strengthened if the period between changes in RPC were extended, perhaps through a mechanism similar to rate cap. For example, the RPC figure could be held constant for a period of years, or it could be allowed to change only in relation to economic events outside the utility's control, such as inflation. Our own preference is for relatively long periods -- five to seven years -- between cost reviews. We would rely on either external inflation indices or yardstick approaches to adjust revenue levels between rate cases.¹⁶

This option also relies on franchise auctions to reduce distribution costs and to manage power supply acquisitions. One important feature of this option is that it can be structured to give the utility a significant incentive to minimize its own contribution toward DSM costs while maximizing the portion of costs borne by the participating customers. The use-per-customer term shields the utility from any revenue loss due to DSM, while the DSM term ties financial performance to the kilowatt-hours saved, independent of what a utility pays to save them. Thus, the utility profits most when its participating customers foot most of the DSM bill.

RPC approaches often have stabilized the utilities' revenue stream. Revenues fluctuate due to a

⁰See Bill Indexing, in *Regulatory Incentives for Demand-side Management* by Nadel, Reid and Wolcott, ACEEE 1992, where the use of external bill indexing is used as a long-term yardstick approach to incentive regulation.

number of factors, most notably energy efficiency investments, weather patterns and economic cycles in the utilities' service territories. One positive feature of this option is that it removes these sources of revenue volatility by having customers compensate the utility through the use-per-customer calculation. Before adopting this approach, the likely impact of this risk shift should be considered. If necessary, it is possible to modify the revenue formula so that the utility still bears some or all of the risks of sales fluctuations due to weather and the economy.

A shortcoming of this option is its failure to offer consumers a chance to exercise their prerogative to support energy resource portfolios with more or different diversity or with different levels of risk. When the utility assesses the risk they are willing to assume, that resource decision is made based upon the utilities', not the customers' needs. More direct, contractual relationships between the consumers and power suppliers are one way to address this concern.

OPTION TWO

Retail Wheeling Frameworks

The Case for Retail Wheeling

Proponents of retail wheeling claim that if utilities opened transmission systems and allowed large customers access to alternative suppliers of electricity, customers would be able to lower their electricity costs and become more competitive in international and national markets. Under a retail wheeling framework, rather than pay the existing high retail prices for electricity, these customers could shop around for the best deal. In doing this, they could buy transmission and distribution services from their local utility and unbundled electricity generation service (capacity and energy) from a different supplier. The total charge to these customers would be the combination of the wheeling charge paid to the local utility and the capacity and energy charge paid to the supplier. The supplier could be a neighboring electric utility, an IPP, an electricity broker or an industrial firm's own co-generation facility located at a different site.

There are two arguments in favor of retail wheeling.

1. Cost reductions. Retail wheeling can reduce costs, rather than merely shift costs from one customer to others. This can happen if, as supporters of retail wheeling contend, utilities currently either ignore cost-effective, non-utility generating opportunities, or they simply fail to negotiate new supply contracts as vigorously and effectively as is possible. Proponents argue that allowing customers to negotiate and acquire new power supplies will result in cost savings that are shared by all customers. In addition to lowering supply-side costs, proponents often credit the threat of retail wheeling with the recent industry trend to reduce overhead and administration costs.

2. Future investments. Utility investment decisions are necessarily biased by the risks that they perceive are attached to different resources. If their judgment or perception of risk is

significantly different from the risks customers are willing to take, then the resources utilities choose may be different from resources that customers would choose. Retail wheeling, then, could be seen as a means to alter resource selection even if costs are not reduced.

The Case Against Retail Wheeling

There are three primary arguments against retail wheeling.

1. Cost shifting. It is argued that retail wheeling is, in reality, an attempt to shift costs away from one customer (often a large industrial customer) onto other customers. This could occur, for example, during a period of capacity excess. Here, industrial customers would buy short-term power at a depressed price. There would be no overall cost savings since the utility would presumably have access to the same power at the same or even a lower rate. Still, the industrial customer would save as long as the cost he was paying was less than the price he would pay the utility. But his savings would be accompanied by a shifting of costs onto the remaining customers. Only if the wheeling customer were able to acquire power more cheaply than the utility could acquire it would there be an overall cost savings which would benefit the wheeling customer without financially burdening other customers. Opponents often argue that the threat of retail wheeling is a reallocation of costs to other customers.

2. Fairness. Retail wheeling customers will opt out of the utility system whenever the market cost of power is low. However, when the market price rises above the utility costs, as would occur from time to time if the utility had long-term, non-market price resources,¹⁷ then wheeling customers would quickly opt back into the utility system. The result would be a "Heads you win, tails I lose" system for other customers who would bear the full costs of the utility's long-run resources in those years when market costs were low but would not get the full benefit of the utility's long-run investments when market prices rose.

There is a related concern as well. If wheeling customers are free to opt on and off the system more or less at will, then it makes utility planning very difficult. In essence, it forces the utility to plan for a load which may vanish and reappear randomly. And again, the residual customers are left to bear the costs of the inefficiencies stemming from this uncertainty.

3. Environmental. Utility planners often consider (or should consider) the externality effects of their decisions, particularly the effect of resource selection on the environment and the economy. Under most retail wheeling frameworks, there is no mechanism to assure environmental externalities are taken into account. Retail customers are probably less likely to factor these considerations into their analysis. This concern is an important reason to consider Option 3, emission taxes.

⁰ This assumes that the utility, as a franchised monopoly, is prohibited from charging what the market will bear.

Retail Wheeling: are sunk-cost issues merely transitional?

In one fashion or another, retail wheeling opponents cite the large "sunk" cost that retail wheeling would shift to captive customers or utility shareholders. Advocates of retail wheeling dismiss these as "transitional" issues that have no long-term consequence. The FERC also seems to view "stranded" plans as a transitional issue.

Our approach focuses on the future more than the past and is therefore quite different. Rather than asking who should pay for sunk or transition costs, we ask instead how do we create a retail wheeling framework that is consistent with IRP principles. At its heart, IRP seeks to distinguish between those demand- and supply-side resource **additions** that are cost-effective and those that are not. This identification and acquisition of cost-effective resources rather than sunk-cost allocation is our overriding objective when designing a retail wheeling framework. Equally important in this analysis is the fact that we do not see sunk or transitional costs as a temporary problem.

Elementary economics texts define natural monopolies as industries where it is less costly to have a single monopoly provider than to have multiple firms competing to provide service. Economic theory, though, offers another way to define natural monopoly -- the Core theory¹⁸. Core theory considers the issue of natural monopoly by asking whether, given an industry's cost and demand characteristics, a market equilibrium, among multiple firms, can occur. If no stable, competitive equilibrium exists, then the industry is said to have an "empty core" and is a natural monopoly.

If the industry is characterized by plants whose costs decline as output increases, if demand is subject to volatile change, then the core is likely to be empty. The same potential for an "empty core" may exist for capital-intensive industries that chronically have excess capacity. The nature of the electric utility industry is such that it is in chronic excess. The fact that electricity cannot be stored, that the supply must meet demand on a minute-by-minute basis, that the product requires an interconnected grid and that the political reality means heads roll if the lights go out are all reasons why the system is nearly always long. If we always have at least enough, we are arithmetically assured of having too much on average. Therefore, if the electric industry is chronically in an excess capacity condition, then at least certain competitive market structures can yield prices that are both too low to give consumers the right price signals and too low to sustain the industry.¹⁹

⁰ Lester G. Telser, Economic Theory and the Core, University of Chicago Press, 1978.

⁰This tendency to be long is not, per se, bad. It is worth something to insure that the lights stay on. But it has a difficult implication. In a regulated environment, excess capacity generally means prices are high. The converse is also true. In a completely competitive environment, excess capacity means prices are
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The issue here is whether different possible structures for a competitive electricity market will have a strong enough core to yield a stable equilibrium. If there is chronic excess capacity, prices probably will be driven down to short-run marginal costs. This raises two problems. First, it suggests that the sunk cost issue is not merely a transitional issue. If widespread, it could threaten the ability of utilities to remain solvent. This places system reliability at risk and even though some economists may find this acceptable, the public while appreciating low prices, will not tolerate reduced reliability. Secondly, the tendency to expect artificially low retail prices would lead to inadequate investment in energy efficiency, profligate use and cause environmental harm.

We cannot predict whether a deregulated electric generation business, with retail wheeling, will or will not lead to a stable equilibrium. Some forms of competition might lead to an empty core, and others may not. The British experiment is too new to draw any firm conclusion. To date, prices have had more volatility than some observers expected, causing the regulators to open an investigation. The extent to which prices will show stability in the future will probably be because most retail customers did not change suppliers and because most wholesale transactions between wire utilities and generation companies, especially new power plants, have come with long-term contracts.

Regardless how serious or likely an empty core would be it is clear that how competition is structured matters. A reasonable place to begin considering how to structure utility competition to avoid core related issues is to look at approaches designed to promote competition aimed at lowering costs, not simply lowering prices for some customers at the expense of others.

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low.

Option 2A

Retail Wheeling Framework, Anyone Supplies Kilowatt Hours

It is possible to construct a retail wheeling framework that guards against the two most serious concerns associated with retail wheeling -- namely the acquisition of resources that are uneconomical and the creation of unstable energy markets.

Consider first what would happen if our ideal rate designs were in effect. In such a regime we want to encourage competition based on the lowest cost supplier, something that will be reflected in the values of c_i . However, a retail wheeling customer may be able to avoid paying f_i by taking no retail service from the local utility and taking FERC jurisdictional transmission service only. If the f_i 's were included in retail wheeling rates, competition would be based on the relevant marginal costs rather than primarily the response to natural incentives to avoid uneconomic sunk costs and the costs of social obligations that have been imposed on utilities.

While it may be impossible (and for some purposes undesirable) to have these types of retail prices it may be practical to apply the same principles to retail wheeling rates.

Retail wheeling rates should be priced to encourage wise economic decisions and discourage poor decisions. To do this, the retail wheeling rate (RWR) would equal the prevailing retail rate (RR) minus the utility's relevant marginal supply costs (MSC).

$$\mathbf{RWR = RR - MSC}$$

Relevant marginal supply costs are the incremental, out-of-pocket costs needed to provide energy and capacity to a particular customer over the time period that the customer seeks retail wheeling services.

One of the challenging tasks of a retail wheeling framework is to avoid the possibility that direct IPP sales to consumers are viewed as being more economical solely because the utility's supply decision - and hence costs - are influenced by environmental externalities, and the IPP's supply costs are not. To address this situation, at least until broad-based emission taxes are in place, the MSC used in the formula needs to be adjusted. The simplest option is to adjust MSC to reflect the environmental externality costs which have been internalized in the utility's supply choices. The departing customer, therefore, does not avoid these costs when choosing another supplier. A more complicated but preferred approach would be to reflect the **difference** between the externality cost of the utility's marginal supply and that of the IPP.

The purpose of this approach to setting retail wheeling rates, including the environmental adjustments, is to eliminate the likelihood of uneconomical power supply choices. In this case, any customer considering acquiring her own supply of electricity would face two separate charges. The local distribution utility would charge the RWR described above. The new supplier of kilowatts and kilowatt hours would impose charges for their services separately (SSC). The

customer's new retail rates (NRR) can be expressed in the following formula:

$$\text{NRR} = \text{RWR} + \text{SSC}$$

The question becomes, under what conditions will the customers' new retail rate (NRR) be less than its original retail rate (ORR)? After all, it is only when NRR is less than ORR that the customer would have a financial interest in pursuing retail wheeling options.

Rearranging the formulas shows that NRR is less than ORR **only** when SSC is less than MSC. In other words, using this retail wheeling framework results in an economic benefit to customers engaging in retail wheeling services **if, and only if**, their new supply-side cost is less than the local utility's marginal supply cost. This is precisely the desired result.

This retail wheeling framework accepts the legitimacy of the most cogent argument for retail wheeling - the acquisition of truly cost-effective, supply-side resources - but does not result in shifting costs from one customer class to another. This framework permits customers to engage in retail wheeling, but it yields an economic advantage to the customer only when purchases are consistent with the IRP principles of acquiring resources that cost less than the local utility's marginal cost. If the customer succeeds in locating and acquiring such resources, she keeps 100% of savings.

This framework also avoids the risk that prices in a persistently (and prudently) excess capacity condition will be too far below long-run marginal costs. Prices to consumers should reflect long-run marginal costs, including environmental and other externalities. This allows consumers to make more rational, long-term investment decisions between things that cost less today but use a great deal of energy, such as a poorly insulated home and things that cost more today, but use less energy, such as investments in energy efficient lighting.

Some level of retail competition exists now in the form of DSM, fuel switching and self generation. To be sure, there are formidable barriers to customers adopting these options, one of which is that each of these options require long-term capital commitments. The customer needs to buy a more expensive home or appliance or invest in a more capital intensive, but more efficient industrial process.

The British experience provides some interesting insight here. While it may have been expected that competition for new power supplies in the U.K. would occur as a result of the short-term pool pricing mechanism, most, if not all, competition for new generation in the U.K. involves long-term contracts with distribution utilities. If sophisticated developers with experience, expertise and good access to capital require long-term contracts before investing in power plants, is it reasonable to expect ordinary consumers to invest in DSM or self generation without long-run, marginal cost-based prices?²⁰

⁰Setting electricity prices at long-run, marginal costs is similar, in some respects, to imposing long-
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In addition, there are some other details associated with this retail wheeling framework which merit consideration:

1. There may need to be a floor on the retail wheeling rate. For example, regardless of the results of the formula given above, one might require that the rate not fall below the local utility's marginal cost of providing wheeling services. A more extreme case would be to prohibit the rate from dropping below zero.
2. Marginal supply cost is customized to reflect the load characteristics of the customer, the location of customer and the new source of generation. This cost also hinges on how long the customer wants retail wheeling services. For example, the customer might ask for wheeling services for just one year. In this instance, the marginal supply cost would reflect the marginal or avoided cost for the one year period. If the customer asks for retail wheeling services for five years, they would be given a series of marginal or avoided (not leveled) costs for the five year period.
3. There are a number of issues regarding the local utility's obligations to serve wheeling customers after the wheeling contract expires. What obligation, if any, does the local utility have to provide generation to these customers? At first blush, absent notification by the customer, the utility could retain the obligation to serve and plan its resource decisions accordingly. If it makes capacity commitments and the customer later decides to leave the system again, the retail wheeling rate formula assures that the customer does not avoid paying for the capacity. If the customer returns, the utility would provide service at the same rates paid by customers who have remained on the system. A remaining question is should the local utility make any commitments in the expectation that these customers could return?

ENVIRONMENTAL COSTS

Utilities have an obligation to take the costs of environmental compliance into account in their planning, investment and operating activities. To the extent that there are costs imposed on them by state and federal environmental regulations they are already taken into account. Where planning and investment activities are less likely to be doing a good job is the obligation to incorporate expectations and associated probability and cost estimated about future environmental constraints into the planning process using appropriate techniques for planning under uncertainty. The regulatory process will have a much more valuable impact on environmental compliance if it focuses on encouraging utilities to improve the way that they incorporate uncertainty into their planning and investment decisions, including uncertainty about

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term contract requirements on customers.

future environmental compliance costs. This is especially important since uncertainties about future electricity demand growth, technologies and environmental regulation have increased enormously since standard utility planning tools were first adopted.

Nor is this a prescription for abandoning a commitment to internalize environmental externalities in sensible and efficient ways. That's why we have environmental laws and that's why we have environmental regulators. Public utility regulators should be on their backs to do a better job.

Emissions Taxes, Substitute for Income Taxes

This option on emissions taxes is not a separate structural or regulatory option. It is included in this paper, however, to provide a practical step toward taking environmental externalities into account in a competitive market.

Most would agree with the principle of user taxes, in this case emission taxes, to internalize costs. From this common ground, some argue that absent federal action nothing should be done, and others argue that state and electric utility consideration of externalities is better than nothing. Without taking sides, the question for Option 3 is whether there is there a federal tax-related option that moves in the right direction and is practical enough to bother with in the near term? We believe the answer is yes. To accomplish this, we offer a tax that replaces or supplements federal income taxes by placing an emissions tax on carbon.

The reason for limiting the tax to carbon is predicated on the recognition that CO₂ is a major greenhouse gas and that the Clinton Administration wishes to create partnerships and market-based approaches to reducing carbon emissions. As a first and very practical step, we propose a limited pilot program in which the IRS or another suitable federal agency would be congressionally authorized to negotiate and enter into voluntary tax agreements with willing utilities. Utilities that have entered into CO₂ reduction agreements would be a likely place to start. These utility-specific tax agreements would not affect the tax liability of anyone not a party to the agreement.

For an emissions tax to be considered a plausible alternative, it would have to be viewed by payers (utilities) and receivers (the federal government) as being revenue neutral. Accordingly, both the IRS and the utility would obviously try to negotiate an agreement where the utility accepted an emission tax in return for seeing its income tax liability reduced or eliminated. Obviously, each side would attempt to negotiate an agreement which was at least as acceptable as the status quo.

We stress that the tax agreements would be voluntary and specific for each participating utility. There are many permutations to the tax that could be employed to direct how the tax could best be applied as an incentive to reduce CO₂ emissions.

The simplest structure which could serve as the negotiating framework for the tax agreement to calculate the emissions tax is as follows:

fluctuating current income. For the sake of illustration, assume that NEES's federal income tax obligation is in the range of \$90 million to \$110 million. At \$15/ton CO₂, NEES's federal tax would equal \$225 million. So at first blush the K would be a tax **credit** of about \$135 million. But the imposition of the tax would change NEES's operations, including the dispatch of existing units. This would increase NEES's operating cost and decrease the tax revenues to the federal government.

The cost increase to NEES is much less than \$15/ton on average. This is shown in the following illustration.

The graph reflects the fact that the cost-per-ton of carbon removed varies according to the size of the reduction. Some carbon can be removed (or offset) very cheaply while additional carbon reduction comes at an increasingly higher cost. The amount of carbon reduction is "X" shown on the X axis. Under our proposal, a utility will adopt all measures costing \$15/ton or less.

The result of the tax would be to increase NEES's costs by the amount shown in the shaded area under the curve. The tons of carbon remaining to be taxed at \$15/ton is the difference between the amount originally expected and the amount removed as a result of the \$15/ton tax.

NEES will try to negotiate a K so that its total tax liability is roughly \$100 million, minus its cost increase as shown on the graph. The IRS will try to negotiate a K which takes into consideration NEES's expected response to the carbon tax and still leaves the Treasury with about \$100 million. Both parties will take into account the variability of the tax burden and the other benefits of the new tax regime. With luck an agreement can be reached.²¹

This option has benefits for utilities, customers and others. For the Clinton Administration and the environment, the greatest benefit is that carbon emission will no longer be free. New plant decisions and the operation of existing plants will be influenced by the \$15/ton emission tax. By

²¹If, for any reason, it is desirable to have a tax that more closely resembles an income tax structure, the negotiation between the IRS and the utility could be reflected in the following, alternative equation.

$$\begin{array}{cccc}
 \text{Income taxes =} & & & \\
 \text{due} & & & \\
 & \text{Income taxes -} & \text{Tax credit +} & \text{\$15/ton for carbon} \\
 & \text{as normally} & \text{to be} & \text{dioxide emissions} \\
 & \text{computed} & \text{negotiated} & \\
 & & &
 \end{array}$$

With this formula, the utility's actual income taxes would be a function of both income and carbon emissions. The term to be individually negotiated would be the tax credit. As was the case with the first option, in both structures the \$15/ton tax remains fixed. This formulation reduces the negotiations to a simple matter of how the cost of reducing carbon emissions will be shared.

making the tax utility specific, it is possible to create tax agreements that do not affect the utilities' competitive position.

Utilities receive both short- and long-term benefits. In the near term, this approach is likely to result in some sharing of the cost of emission reductions between the utility and the federal government. It also may (should) relieve the federal government of the obligation to apply environmental adders at the state level. The option may also provide utilities with flexibility and financial incentives to find cost-effective ways to reduce carbon emissions. Finally, the option presents a practical step to begin applying an externality tax to other major CO₂ contributors who are also competitors.

State Regulatory Consideration

The relationship of the proposed emission tax to state regulatory proceedings varies. In some states, the utility would receive the full benefits of any tax savings until the next general rate case. The longer the period between rate cases, the greater the incentive to reduce carbon emissions. At the time of a rate case, state regulators would decide how much, if any, of the tax savings the utility would retain on a prospective basis.

In other states, a tax on carbon emissions might be considered a fuel cost subject to existing fuel adjustment clauses. If this were the case, incremental taxes incurred or incremental tax savings would be passed on to customers directly. However, this would reduce the very financial incentives the emissions tax is intended to create. For these reasons, it may be desirable to ask state regulatory commissions to specify the regulatory treatment of emission taxes. We would hope that regulatory treatment would be consistent with the principle of trying to provide incentives to reduce emissions.

Other Attributes

The tax also has the following attributes:

1. The approach is in keeping with the partnership spirit of the President's Climate Action Plan
2. It provides another opportunity to evaluate the utilities' ability to respond to a market-based system
3. It provides a basis to move away from state-by-state environmental adders for carbon
4. It provides a framework that could be applied to competing energy suppliers
5. It provides experience for later changes in tax laws

6. It allows the principle of revenue neutrality to apply to utilities with very different resource mixes

There is significant work that needs to be done to flesh out these ideas. But if the concept has merit, most of the remaining issues can be explored in individual utility negotiations. This may offer the best opportunity to develop an effective way to internalize environmental costs.

FERC Role

The FERC should play an especially important role in creating and/or encouraging workable market-based frameworks. IRP principles, we again stress the difference between IRP principles and the choice of regulatory process used to assure implementation, guide regulatory and utility judgment on a wide array of resource acquisition issues. The FERC does not apply a consistent set of IRP principles across all these related issues, but it should. A few examples illustrate this problem.

Multi-state utilities allocate systemwide costs to retail jurisdictions based on FERC-approved contracts or tariffs. Consistency with IRP, while critical, is a missing element of the FERC review and approval of these contracts. By not taking IRP into consideration, the disparate accounting of costs and benefits of different resource options distort resource selection decisions. DSM costs, for example, are typically assigned based on geographic location while the resulting fuel and capital cost savings are assigned elsewhere, such as happens now under the Entergy system agreement. When this happens, contracts are established in a manner that is inconsistent with IRP principles, and the resulting contract provisions can be unfair.

Power pooling agreements provide another example where FERC review would benefit from applying a consistent set of IRP principles. If pooling agreements mismatch cost and benefit flows, pool members will make poorly informed or biased resource decisions. One example is power pooling agreements that assign capacity or reserve requirement costs without regard to the characteristics of the power supplies individual members add to the pool. The cost differences can be very large, and if ignored by the pooling agreement, the resource additions will be (and have been) biased.

The role of the FERC in the retail wheeling is indirect but nonetheless important. Although the FERC has no jurisdiction over retail wheeling, it alone has a long history of setting prices for transmission services. In its wholesale, ratesetting jurisdiction, there are countless examples where the underlying principles and issues the FERC considered are identical to ones considered by state commissions. Unfortunately, FERC's approach to these cases has been very narrow. Their analyses have looked at the more typical cost-of-service, cost allocation, prudence and equity concerns that are characteristic of rate cases involving cancelled power plants and the like. These cases would benefit from applying IRP principles.

In particular, there have been a number of recent cases in which utilities sought approval to include "stranded investment" costs in transmission charges where a wholesale purchaser

switched, or threatened to switch, to another supplier. This "stranded investment" charge as it is being proposed would apply to historically full or partial requirement customers who leave their current supplier(s) to take advantage of lower prices offered by others, typically suppliers with excess generating capacity. By seeking to impose such a charge, the transmitting utility is trying to recover the costs of generating capacity that was originally acquired to serve customers who later opted to leave the system. The FERC's review in these cases to date has focused on cost allocation and equity concerns more than on IRP. Under an IRP framework, the key question would be what transmission prices would yield a competitive market structure able to reduce (rather than shift) costs. Stated another way how would different pricing policies create competitive markets that encourage cost-effective resource acquisition and discourage acquisition of non-cost-effective supplies.

IV. Concluding Remarks

Our assignment was to describe industry and regulatory structures that use retail competition to meet the energy service goals set collectively in earlier Energy Foundation group discussions. We have described a number of different options and variations to achieve these goals.

Competition in the wholesale and retail markets can be a very effective way of reducing costs. On the other hand, retail competition can be very different from retail wheeling. Retail wheeling helps to meet our goals only where it lowers costs, increases efficiency and lowers environmental impacts. The approach to wheeling developed in this paper, if carefully adhered to, addresses the cost and efficiency concerns.

A key issue in the debate is whether the focus of competition is on customer's total bill or the cost of a kilowatt hour. If the regulatory and competitive environment is structured in a way that focuses primarily on price per kilowatt hour of electricity supplied, there will be only marginal activity on the part of utilities to use DSM as a product enhancer. This is true with or without retail wheeling. If there is no retail wheeling, then the monopoly provider will find energy efficiency contrary to its best financial interest precisely because it eats directly into its profits. While it is possible to imagine specific circumstances where energy efficiency may be one of the strategies to deal with the competitive challenges arising from retail competition, in most cases it will not be used. Instead, it is far simpler and safer for the utility to respond by cutting prices than by offering narrow and targeted energy efficiency programs. For example, traditional regulated utilities have rarely used energy efficiency to respond to competitive pressures.