PERSPECTIVES IN ELECTRIC UTILITY RESTRUCTURING

A compilation of papers prepared by The Regulatory Assistance Project

February 1996

Tom Austin
Peter Bradford
Cheryl Harrington
Edward Holt
David Moskovitz
Carl Weinberg

Ellen Baum, Editor

THE REGULATORY ASSISTANCE PROJECT
177 Water Street, Gardiner, Maine 04345-2149
Telephone (207)582-1135 FAX (207)582-1176
e-mail: rapmaine@aol.com

PERSPECTIVES IN ELECTRIC UTILITY RESTRUCTURING

A compilation of papers prepared by The Regulatory Assistance Project

February 1996

Funded by

U.S. Department of Energy, Grant Number DE-FG41-93R11058
U.S. Environmental Protection Agency, Grant Number X824344-01-0
The Pew Charitable Trusts
The Energy Foundation
Joyce Mertz-Gilmore Foundation

Table of Contents

Perspectives in Electric Utility Restructuring

Preface

This volume is a collection of papers based on a series of writings and workshops on competition in the electric utility industry. The Regulatory Assistance Project (RAP) presented the workshops to commissions and commission staff in states across the country in late 1994 and 1995.

RAP is a non-profit corporation, originally formed to assist state regulatory commissions in the adoption and implementation of Integrated Resource Planning (IRP). RAP's workshop and other assistance is provided free to commissions. Each workshop is individualized to meet the needs of the host state. RAP is funded by the U.S. Department of Energy, the U.S. Environmental Protection Agency, The Pew Charitable Trusts, The Energy Foundation and Joyce Mertz-Gilmore Foundation.

This volume was prepared with assistance from Beth Heath, Karen Nielsen and Anne Petersen. The papers reproduced here, and our own thinking as well, have benefited immeasurably from thoughts, questions and views put forth by innumerable state PUC workshop participants.

The volume is designed to serve several purposes: as preparation for future workshop participants, as an after-the-workshop reference and as a stand alone survey of the major issues commissions face as they consider restructuring of the electric utility industry. We have tried to make each chapter an independent paper, capable of standing alone. Still, the first five chapters should be viewed as laying the framework for those which follow.

The volume describes, both broadly and in some detail, many of the key issues which state regulators will face in the transition to a more competitive industry. We hope we have provided a resource which will aid regulators in guiding a reasonably smooth transition to a world in which electricity customers have an increasingly wide array of low-cost energy resources.

Considering Competition

Increased competition is coming to the electric utility industry. But what does this mean? Why has it appeared so suddenly? What opportunities does it offer? What problems? What should state regulators be doing to prepare for the major changes that competition will demand? These are questions frequently asked at state public utility commissions today.

This compilation of papers is based on a series of workshops presented by the Regulatory Assistance Project (RAP) to commissions around the country. The papers look at the emergence of competition in the electric utility industry from the perspective of state utility regulators. They lay out some of the major choices facing public policy makers and examine the key questions state regulators need to resolve as competition develops. The special problems of transition from a regulated to a more market-based industry are discussed, and the activities underway at the federal level to create competitive conditions are described.

WHY COMPETITION NOW?

It is helpful to begin a discussion of competition in the electric industry by considering events that led the industry to where it is today. A review of recent history will show the impetus for change did not come as suddenly as many think. Over the past decade, the combination of a few major events, together with several smaller but significant factors, brought the industry to the threshold of major change and reformation.

Marginal Costs Are Lower Than Rates

The single largest factor driving the move to increase competition is the difference between today's low marginal cost of electric power production and existing rates which are set to recover costs incurred in the past. Current marginal costs for new generation in many parts of the United States are significantly lower than existing rates. Customers, particularly large customers who are well aware of the lower costs of producing electricity today, want to stop paying rates that include recovery of embedded costs and pay marginal costs instead. This understandable desire to pay lower rates (a desire undoubtedly shared by customers of all classes) has created significant political momentum to bring competitive choice into the electric industry.

Marginal costs are lower than average costs in many states for three reasons: decreasing cost of fossil fuel, especially natural gas; reduced capital cost and improved efficiency and reliability of gas-fired combustion turbine and combined cycle power plants; and, in much of the country, excess capacity.

Success Of State And Federal Laws

Ironically, the successful implementation of resource planning and acquisition practices by state public utility regulators has hastened the arrival of competition in the electric industry. The broad adoption of Integrated Resource Planning (IRP) by state public utility commissions created a sophisticated public process to compare the costs and attributes of a variety of generation- and demand-side resources.

The IRP process created a regulated market where different types of resources could compete for inclusion in utilities' resource plans. Many states and utilities supplemented their IRP processes by implementing the federal 1978 PURPA law and requiring competitive bidding to select new resources. A number suppliers responded to requests for bids. The abundance of bids at very reasonable prices demonstrated that the generation of electricity is essentially a competitive enterprise. In fact, the success of bidding not only showed many suppliers were capable of generating electricity at very competitive prices but also motivated some customers to ask for the opportunity to buy electric power from suppliers of their own choice rather than from their current utility.

Building upon IRP and PURPA, the federal Energy Policy Act of 1992 (EPAct), which called for the opening of transmission access to allow any wholesale seller of electricity to serve any wholesale buyer, was enacted. Since the passage of EPAct, the Federal Energy Regulatory Commission (FERC) has moved steadily to define and implement open transmission access in a manner supporting a fully competitive wholesale electricity market. The process has been neither easy nor fast. The objectives, however, are clear: the transmission system should operate as an open access highway linking all possible sellers with all possible buyers, without creating unfair economic loss to the existing owners of transmission.

Other Contributors To Restructuring

Complementing the PURPA/IRP experience in the United States has been the experience of several other countries in replacing inefficient, government-owned monopolies with competitive electricity markets. The United Kingdom's creation of a competitive electricity market early in the 1990s has been very closely studied. Other countries including Norway, Chile, Australia and New Zealand have also engaged in major structural changes to their electricity industries to create competitive electricity markets.

In addition to the activity in the electricity sectors of other countries, the deregulation of several other industries in the United States has played a part in rethinking whether there is a continued need for a fully regulated monopolistic electric utility industry. The largely successful substitution of markets for regulation in airline, natural gas and long distance telephone industries has been considered, on the whole, to have reduced costs and increased the variety of services offered. Of course, the changes in these industries have not come without some debate and dissatisfaction. There are certainly consumers who would argue that quality of service has deteriorated, real costs have not declined or, in the case of airlines, the industry itself has remained financially unstable. Nonetheless, it is unlikely these industries will return to a regulated monopoly status.

Finally, worldwide there has been a growing reliance on free markets and competition as the preferred public policy approach to increasing social welfare. This philosophic preference for markets does not advocate for abandoning all regulation, but it does signal an interest in economic solutions that are driven primarily by consumer choice, not by government planning.

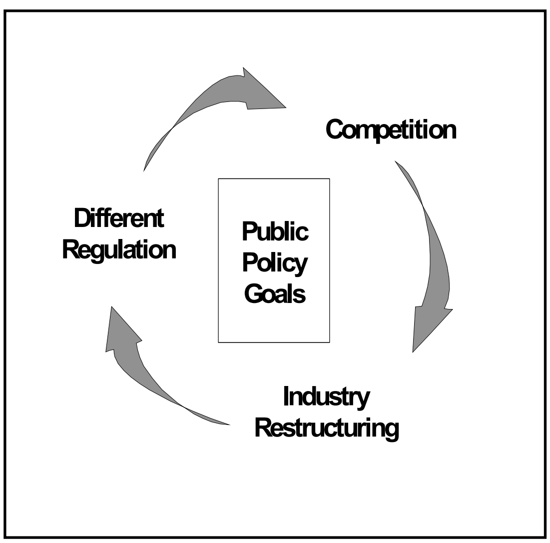
WHERE SHOULD STATE REGULATORS BEGIN?

As they consider the emergence of competition in the electric industry, state utility regulators need to consider and resolve three separate but closely related structural issues:

1. What services can and should be competitive?

2. What industry structure is needed to support competition?

3. What regulatory structure is required both to insure competition is fair and to oversee those services that are not competitive?



These three basic questions can be successfully resolved only after first establishing what features policy makers desire to create or preserve in the electric industry. To do this, there must be a clear statement of the public interest goals to be accomplished.

<u>Identifying The Goals</u>

What are the appropriate goals for restructuring the electric industry? Most state regulators know that statements of the public policy objectives for the electric utility industry already exist in state statutes and in commission orders and rules. Those are good places to start when articulating the principles for a restructured industry. However, new goals, such as customer choice or a preference for market-based mechanisms, may also need to be articulated.

Commissions in Wisconsin, New York, Maryland and Vermont, for example, commenced their consideration of competition by asking parties to identify and comment upon policy goals. They came up with very similar lists that included the following:

- low cost (economic efficiency)
- equity
- universal service
- environmental quality
- economic development
- safety and reliability
- fuel diversity
- customer choice
- energy efficiency
- research and development
- fair opportunity for utility to recover existing costs

- level playing field for competitive services

Most, but not all, have been long standing public policy objectives for the electric industry. Customer choice, for example, is a new goal, and its inclusion reflects the changing expectations that many now have for the industry.

Several state commissions have begun their consideration of the changes in the industry by convening often informal forums to solicit the opinions of all interested parties. When introducing change into such a major industry, taking the time to develop a high degree of consensus among stakeholders is likely to strengthen the success of any outcomes.

What Form Of Competition?

The implementation of IRP, PURPA and the use of competitive bidding have given many state commissions a taste for wholesale competition. Yet this experience with developing and using markets to select the next resource to be added to an existing system is not the same thing as developing a fully competitive wholesale market. In a fully competitive market, all resources, old and new, compete continuously in real time for wholesale customer selection.

Wholesale is generally understood to mean purchasing electricity for resale. Wholesale sales of electricity are regulated by the federal government, and federal policy clearly favors open and vigorous wholesale markets. Whether to go beyond wholesale competition by allowing retail competition requires state utility commissions to decide whether the end-users of electricity — the retail customers — should be allowed to purchase electric services from the provider of their choice.

While each state will make its own decision as to how to go forward, in reality states rarely operate in isolation. The overlap in jurisdiction over regional utilities and shared transmission lines illustrates how a decision to go forward with retail competition in one state can profoundly impact the policy choices left open to regulators in adjoining but slower acting states. Because of this, there needs to be regional as well as state dialogues on industry restructuring. Also because the jurisdiction to implement change and accountability for the end result are held jointly between state and federal governments, there is an acute need for state federal dialogue.

What Industry Structure?

Bringing the picture of what competition should look like into sharper focus leads directly into the next critical question. How should the industry be structured to most fairly and efficiently deliver the desired level of competitive service?

Today's regulated monopoly is typically vertically integrated. A single electric company (or its close affiliates) supplies all generation ,transmission and distribution services. A utility may also own a major source of fuel supply and a connecting transportation system as well.

Most industry observers believe that transmission and distribution systems, because of the enormous financial and environmental investment required to string a second set of wires, must, for the foreseeable future, remain a monopoly. But if a vertically-integrated owner of generation also has monopoly control of the wires, how well can independent suppliers of generation services compete? Will the integrated company use its monopoly position in distribution or transmission to block fair access by other generators to its transmission or distribution customers? What safeguards are needed to assure the generation services owned by the transmission and distribution monopoly do not receive unfair competitive advantage?

New institutions may be needed to make a competitive wholesale or retail system work, such as a "market" where all possible buyers and sellers meet to make deals. What information must be available publicly to create this market? Some believe the answer is regional power pools (POOLCOs). Others believe that a system operator is needed, but that buyers and sellers will find each other without a centralized market.

There also needs to be a neutral entity charged with overseeing the dispatch and reliability of the system. In a similar vein, regional transmission groups (RTGs) are being formed to coordinate access and use of transmission lines. The creation of any new institutions will require the direct cooperation, participation and ultimately approval of state regulators.

What Regulation Is Needed?

If some services are free to compete in the open market, will there be a continued role for cost-of-service regulation? For competitive services, the obvious answer is "no." But all markets operate under rules. What should the rules for competitive electric markets be?

Of the services that continue to be monopolistic, are there better ways to regulate them? What about companies that offer some services that are competitive and some that remain monopolistic?

Thinking about how to make regulation work better and trying to sort out what are and are not competitive services raises difficult and complex questions which do not lend themselves to simple solutions. Still, this is not the first time utility regulators have had to address such issues. For more than ten years state regulators overseeing the provision of telephone service have had to distinguish competitive from non-competitive services and determine the appropriate regulation of each.

Performance-Based Regulation (PBR) has emerged as a viable alternative to cost-of-service regulation. PBRs set specific performance targets, and a utility's profit is tied to its ability to meet or exceed targets. Most PBRs do not include fuel cost adjustments and are characterized by fairly long periods between rate cases, thus requiring utilities to rely heavily upon their own managerial skills to make a profit. Several state commissions, including New York and California, are increasing their dependence on PBRs. While PBR does not altogether replace cost-of service regulation, it can significantly reduce the intensity of the regulatory process, protect the quality and cost of service and, at the same time, grant utilities flexibility to adapt to a more competitive environment.

Working Through The Options

It can be all too easy to get lost in the many options raised by the possibility of restructuring. The matrix below offers one way of organizing a comparative analysis of some of the different restructuring options.

The vertical axis represents common policy goals, both old and new, that a regulatory commission may wish to achieve. On the horizontal axis are some of the regulatory and competitive options under consideration today. They progress from today's current practice (cost-of-service and IRP) through PBR to different levels of wholesale and retail competition. These options do not encompass the universe of competitive and regulatory possibilities but rather represent the major options under consideration.

Policy Options

Goals	PBR	Fully Competitive Wholesale	Limited Retail Wheeling	Full Retail Competition
Reduce Costs				
Equity				
Environment				
Low Income				
Diversity/ Low risk				
Reliability				
Customer Choice				
R&D				
DSM/Renewable Resources				
Streamlined Regulatory Process				

Working through the matrix requires careful thinking about how each goal can (or cannot) be accomplished under different competitive structures. Eventually a framework of comparative information emerges illustrating the strengths and weaknesses of each approach. Obviously, there is no single best answer, and opinions among states will differ. However, the systematic examination of the goals and choices available to meet them can help to create a better understanding of the possibilities.

RECURRING THEMES

The remainder of this book, while covering a number of topics in depth, keeps returning to four themes.

1. The existing system of regulated monopolies has, for the most part, served the United States well. The country enjoys low electricity prices and remarkably high reliability when compared to the rest of the world. This performance has been maintained at the same time that substantial progress has been made toward reducing environmental emissions, pursuing cost-effective energy efficiency, expanding the diversity of electricity producing resources and insuring that electric service is available to all. There remains, however, room for improvement on all these fronts.

2. Competition is not a goal in itself but a means to an end. Deregulation will provide firms with stronger incentives to

innovate and control costs than even the best regulation can hope to muster. Competition among suppliers, to the extent it emerges, will insure that these cost savings are passed on to customers.

3. Depending upon the decisions made by policy makers, the move to a competitive electricity industry may produce some serious, negative side effects. The most important benefits which are at risk of becoming stranded are energy efficiency, resource diversity and affordability for low income and rural electricity consumers. To minimize negative impacts, an important first step for commissions (and other policy makers) is to define explicitly the goals increased reliance on competition should achieve.

4. For a deregulated, competitive structure to function effectively, a workable level of true competition is a prerequisite. Without vigorous competition among firms, deregulation will fail miserably.

These themes suggest two steps for commissions. The first is to begin the process of considering competition by focusing on goals. The second is to understand clearly the change in orientation competition will (or should) bring to electricity regulation. In most states, commissions and the utilities they regulate have had a number of overlapping interests, the most important of which has been that anything reducing the utility's costs or improving its competitive position tended to lower the cost of electricity to customers. The collaboration that grew from these shared interests were often desirable in a regulated monopoly. In a truly competitive environment, though, these collaborations will be inappropriate. The regulator's role will shift from championing a single competitor to championing competition itself.

Where to Begin —
Golf on a Level Playing Field

The electric power industry is on a slow and erratic path toward competition of a much more pervasive sort than was seriously discussed even two years ago. Because the path is slower and more erratic than it needs to be, it is wasteful from a consumer and a societal standpoint. Many individuals and institutions, however, may appear to gain from the delay. This chapter outlines the governmental issues involved in decisions now being made, discusses briefly the interplay between those issues and presents some utility approaches.

This piece looks at governmental not regulatory issues. Restructuring involves major public policy changes that transcend the jurisdiction of any regulatory body and thus pose something of a conflict for regulators. Optimal outcomes will make regulators — at least traditional regulators — somewhat less relevant.

At least ten substantial public policy issues are raised in the current debates. While not all of these are relevant to all jurisdictions, any proposal that does not make provision for most of them cannot be a satisfactory, stable or long-term resolution. Failure to enumerate these issues clearly is itself a substantial source of confusion and controversy. One reason the process is taking so long is sensible outcomes on so many of these topics challenge the conventions of legislators and regulators who must resolve them. Legislators and regulators will be less able to impose policy through monopoly institutions on a case-by-case basis in a world with fewer monopolies and fewer cases.

TEN POLICY ISSUES

1. **Customer sovereignty.** Will future directions in service choice and technology development continue to be driven by monopoly companies and government regulators? Or will electricity services, like telephone and perhaps gas services before them, become market driven, subject to regulation in the form of the broad-based environmental, antitrust, tax, consumer protection and other laws that affect all industries alike?

   This question cannot be answered in the affirmative simply by committing to wholesale competition, where all generators compete to sell to a transmission and distribution network, organized along the present patterns of vertical integration, with the monopoly transmission and distribution functions remaining tied to the power plants. If that is the best FERC and the states are able to achieve, they will truly have put the cart**(el)** before the horse in a particularly crucial sector of our economy.

   The most pressing customer sovereignty questions look at the extent to which retail customers and/or their agents will have direct access to sellers of electricity and efficiency services (and how soon) and the extent to which companies owning monopoly assets in transmission and distribution will continue to be allowed to compete in businesses where equal and open access to those monopoly facilities is vital. The abuses that flowed when competitive business was linked to a bottleneck monopoly was a major cause of the AT&T break-up. The same issue is a source of continued scrutiny and difficulty in local gas markets. There is no obvious reason to permit such linkage at the level of the generating stations, and there is considerable cause to insist at least on separation of intra-corporate transactions and transparency at other levels of the business.

The litmus test is whether all suppliers and all classes of customers are able to deal with each other over a common carrier system of wires, within a reasonably short period of time. Any other outcome is probably politically unstable, despite the short-term appeal of suppressing competition to reduce exposure to overpriced assets. The benefit of customer-driven competition — its ability bring about technological innovation, organizational efficiency, lower prices and better service — cannot be suppressed by government once the transition is underway. Efforts to do so will lead to a pattern of false expectations and sudden changes reminiscent of the "pro-nuclear" regulation Wall Street viewed favorably — to the detriment of investors — in the 1970s.

2. **Environmental regulation.** What will become of the substantial levels of environmental protection built into current regulation in many states? Among some pro-competition ideologues, these protections are treated cavalierly, as elitist, liberal pork with which utilities and regulators have been buying popularity at consumer expense.

   The federal government has yet to face up to the environmental implications of a competitive electric market. For example, the Clean Air Act Amendments of 1990 created a set of requirements for reductions in emissions that fall, for purely political reasons, more heavily on plants in the Northeast than on a number of the largest, oldest, dirtiest and cheapest plants in the upper Midwest. Given open access, these Midwestern plants will enjoy an unfair economic advantage based on their Clean Air Act exemptions. They may increase their operating hours and sell power more cheaply into regions where plant owners have been required to invest in pollution controls. Prevailing winds will then carry pollutants into the same regions where the cheaper power was sold. This will inevitably lead to more deaths from lung disease, more smog and more mercury pollution in the Northeast. Opposition to this possibility cannot be called elitist.

   Existing energy efficiency programs have also built a layer of environmental protection into utility operations in many states. To the extent competition changes the structures that have delivered these programs, it is important to be sure benefits are captured in other ways. It may turn out a competitive market can deliver environmental improvement more efficiently than the current system, but this can only be the case if such improvement — at least at the levels of protection currently enjoyed

— is a mandatory part of the transition. Otherwise, nothing about a competitive market will protect environmental values. More likely, the reverse can be expected.

Any plan that fails to preserve existing environmental standards and lay a foundation for using market forces to further rather than subvert standards is also unstable and in need of more work.

3. **Strandable cost.** The terms of this debate are familiar, although the extent to which regulators seem to have swallowed the proposition that utilities have an absolute right of full recovery of every dollar not specifically disallowed as imprudent is surprising.[1] This issue is important, but it is not nearly as difficult from a public policy standpoint as others that are getting far less attention.

4. **Nature of regulation**. The issue of how regulation should be applied to the remaining natural monopoly areas unsuitable for competition is of real importance. For example, no serious argument can be made that current service territories maximize efficiency, but traditional regulation puts no pressure on such arrangements. Nor does it create much incentive for research on (or commercialization of) improvements in transmission technology — a substantial source of further savings. Regulation focusing on achieving productivity gains will be crucial in this area. While it is not necessary to spell out the details of such performance based regulation at the outset and while this is not a make-or-break issue by itself, a commission may well want to link restructuring with a move away from cost-of-service price setting.

5. **Tax structure reform.** States like New York that tax utilities disproportionately will have to reform the aspects of their tax structure that impose anti-competitive burdens on utility plants. In the event of divestiture of utility generation, taxation cannot flow through, and utility tax burdens as high as 1000 times greater than their competitors[2] will not be sustainable. This does not exclude a role for taxation of electric generation, but rather it requires taxation to fall on all sellers in a competitively-neutral manner.

6. **Guaranteed access by low-income customers.** Acceptable restructuring of the electric power industry simply cannot be accompanied by a wave of disconnections of people without much money. Most states and the federal government now guarantee a reasonable, basic quantity of electricity through a combination of government funding, regulation of disconnection policies and sometimes lifeline rates or other forms of inter-customer subsidy. These programs must be reconfigured in a competitive marketplace — as they have been in the telephone industry — to

[1] See "A Regulatory Compact Worthy of the Name"; Electricity Journal; November, 1995; pp.12-15 and related correspondence in the January, 1996 issue.

[2] The 1000 MW Sithe Energies facility in upstate New York pays $50,000/year in property taxes. The utility-owned 1000 MW Nine Mile II plant a few miles away pays $50,000,000.

assure a supplier of last resort and a funding obligation that falls fairly on all competitors.

7. **Treatment of nuclear power plants.** Several serious problems surround nuclear power plants in a restructured environment making it unlikely they can be operated on a deregulated basis.

   First, investors may not want to own them if they must really compete. Recent market and pseudomarket tests for nuclear plants here and in Great Britain have not been encouraging, although Britain remains optimistic as to her ability to privatize the better units in the near future. Bids from existing nuclear units in the Northeast lost out to unbuilt, gas-fired plants in New York in 1989-90, and utilities that have closed nuclear units prematurely have not had cause to regret it.

   Second, better economic performance and improved safety have, to date, generally gone hand-in-hand, but there is reason for concern if competitive pressure forces plant managers to trade safety for cost. The Nuclear Regulatory Commission is showing increasing concern over this topic.

   Third, it is unlikely plants will be able to obtain financing for capital improvements if they are not backed by monopoly customers or the government.

   While these points suggest a short but troubled life for nuclear plants under deregulation, the environmental and fuel diversity implications of closing a substantial number of nuclear plants over the next decade are problematic. Sensible environmental legislation and regulation will allow nuclear power the benefit of its clean air and fuel diversity attributes, but only if it delivers these attributes more cheaply than other sources of energy services.

   Of course, some of the nuclear issues should be determined not as "nuclear" but as part of larger resolutions of stranded costs, divestiture and environmental regulation. However, if the nuclear plants cannot (as California seems to have concluded) be moved away from vertical integration with transmission and distribution, some difficult choices among sensible competitive structures, government assistance and nuclear plant closures loom ahead. A case can be made for governmental assumption of decommissioning costs beyond a certain level (since these costs do not increase much with future operation and since their unknown size may be a barrier to finding non-monopoly private owners).

8. **Revision of the jurisdictional line between the federal government and the states.** The outdated and ineffective wholesale/retail distinction would never have emerged were the jurisdictions being established from scratch today.

   The fact that the FERC, Congress, and state policy makers are looking at this issue at the same time provides an opportunity to draw jurisdictional lines more logically.

   Whether or not this reform occurs, more serious efforts to create regional regulatory efforts would improve oversight over both the siting and the pricing of transmission. Such an effort will also mitigate the unease many states feel about restructuring plans that, in effect, transfer much state jurisdiction to the slowness, imprecision, industry domination and impulses toward mediocre uniformity that often characterize federal utility regulation of all sorts.

9. **Market Power.** How will federal and state policy define unacceptable market power in the new electric businesses? To the largest practicable extent, antitrust guidelines should be developed and spelled out from the beginning.

   An important aspect of the market power question is the approach taken toward utility mergers. Utility franchise territories are usually the result of decisions made many years ago on grounds having nothing to do with efficiency. Mergers or territorial realignments are clearly a source of savings, but they are also a source of increased market power. The authority to approve mergers gives state regulators the leverage to encourage separation of generation from monopoly bottlenecks; an outcome regulators might otherwise doubt they have the statutory power to press for. It will also be interesting to see whether regulators take the savings claims routinely accompanying merger announcements as a basis for setting future rates.

10. **Role of public power.** Public power has a mixed history. At its best, it has been a source of visionary innovation and a yardstick against which private companies could be tested continuously. At its worst, it has been a trough of tax-exempt financing through which subsidies have been distributed in ways having little or nothing to do with the real economic interests of the public. As a future competitor in the generation markets, entities with tax exempt financing present obvious complexities. They may also offer substantial benefits as potential owners or operators of the common carrier monopoly points and in easing aspects of the nuclear transition. The State of Maine is also using tax-exempt financing to reduce its exposure to high independent power contracts, though it may be missing an important opportunity by simply flowing through the resulting rate reductions rather than creating a larger bargain in which some serious restructuring takes place as well.

This is a rapid tour of the items that should be on a checklist for evaluating electric restructuring proposals. Reliability is not on this checklist because it seems to have replaced patriotism as the last refuge of scoundrels. Reliability should not be in serious jeopardy under any responsible outcome. It is being used these days to argue for going very slowly by those who want delay for other reasons.

For contrarians who do not like lists of ten, an eleventh topic might be the extent to which the regulatory agency has assessed its own human and financial resources, regulatory and management processes and sense of mission in light of the very different industry that lies ahead. The skills and the processes essential to traditional rate cases will need to be supplemented and modified if regulation is to continue to perform well. If the telephone industry is any guide, electric regulators are going to have more, not less, to do over the next decade, but they invite exasperated dismissal if they proceed on the premise that they alone need not change.

Wholesale Competition

Wholesale competition aims to expand reliance on the competitive market for wholesale (sales for resale) power transactions while maintaining the existing monopoly franchise for retail distribution. The sanctity of the service territory remains, and customers are not given an option to shop for alternative electricity providers. Simultaneously, monopoly utilities continue to have an obligation to serve as well as an obligation to plan and acquire resources to meet the expected level of future customer demand.

This chapter looks at wholesale competition: what it is and what needs to be done to move from today's structure to a fully competitive wholesale market where all generation purchases, including utility generation, become competitive.

WHY MORE COMPETITION?

Wholesale competition offers three potential benefits: cost reductions; use of markets to balance reliability and cost; and a change in how risks are allocated between customers and electricity suppliers.

<u>Cost Reduction</u>

Traditional regulation does not provide utilities with particularly strong incentives to reduce costs. The primary disciplines on costs come from rate cases and through regulatory lag.

Rate cases are quasi-judicial, administrative reviews of a utility's past and/or projected expenditures and provide some oversight on major cost items. If regulators find that particular expenditures are imprudent, those expenditures are excluded from rates. In practice, commission's focus detailed reviews and cost disallowances to a handful of expenditures where large sums of money are at stake, such as major cost overruns at a new generating plant. Time and resource constraints limit the extent to which thoughtful review occurs over the vast majority of the more mundane expenditures a utility makes.

Regulatory lag is the period between rate cases. Once prices have been established in a rate case, the utility's actual profits (as distinguished from profit levels established in the rate case) are the difference between its revenues and costs. Cost savings in areas not subject to automatic rate adjustments translate directly into increased profits. Regulatory lag probably provides more of an incentive to control costs than the rate case process does.

While this regulatory system has worked passably well for almost a century, it has three flaws. First, the incentive to cut costs is fairly weak, particularly if rate cases are frequent. Second, utilities resist taking risks. Fear that a commission would find costs to be imprudent probably discourages risk taking to a greater degree than would occur were decisions being made in a competitive market place.

The third point strongly reinforces the second. Under traditional utility regulation, customers ultimately bear the risk of prudent, but in hindsight unfortunate, decisions. Nowhere is this more clear than in the current arguments in favor of utilities

Perverse Incentives

For a regulated utility, the profit incentive to reduce costs is generally weak and often perverse. For example, over fairly short periods of time, a typical utility can pursue two avenues to reduce costs. It can purchase low-cost power from others, either through pooling arrangements or bi-lateral trades, and/or it can improve the efficiency of its own system by increasing fuel efficiency and reducing losses on the transmission and distribution system. The system, however, does not give equal standing to these two choices. Utilities with a fuel adjustment clause will select power purchases even if the efficiency improvements cost less. The cost of power purchases (or losses for opportunities missed) are passed on to ratepayers and have no impact on utility profits. On the other hand, money spent on power plant efficiency improvements, by costing the utility money, will reduce profits. Because the savings will come in reduced fuel costs, the fuel clause will pass the lower costs directly through to the customer.

receiving full recovery of stranded costs. In fact, stranded costs are the economic burden of what have turned out to be unfortunate choices, principally the acquisition of new generation sources.

Market-Based System Reliability

Under the traditional regulatory regime, to insure system reliability, utilities tend to overbuild. A combination of knowing monopoly franchise customers are obligated to pay all prudently incurred costs and a fear that the public and political consequences of shortages will be much more severe than excess supply, has led to the chronic position of excess capacity. This has caused average costs to be significantly higher than marginal costs.

Advocates of the most competitive industry structures (wholesale or retail) wish to eliminate the current practice of building power plants to meet preestablished reliability standards (a loss of load probability of one day in ten years) and replace it with a model that allows market prices to rise as supply dwindles. Reliability is then determined by a balancing of demand and supply where customers and suppliers respond to market prices.

Risk Allocation

In the current regulatory structure, ratepayers pay prudently incurred costs regardless of how those costs match actual market prices. If the utility makes a bad (however well-intentioned) investment, market prices will be below the utility's costs, and customers will suffer. Conversely, if the utility makes a smart choice, market prices will be above the utility's costs, and customers will be the beneficiaries. In either case, the utility recovers its costs.

This does not occur outside of the world of regulated monopolies. In the competitive arena, those who make the decision either reap the benefits or pay the price for investment decisions. In a competitive generation market, customers pay market prices. Utilities making bad investments suffer the consequences. A smart utility acquires power for resale that cost less than market prices. Customers pay the market price, and the utility realizes a profit. Customers who today believe market prices are well above utility costs quickly opt for this shift in risk allocation. Other customers, who have low prices or who wish to be insulated from volatile market prices, may prefer traditional risk allocation.

RANGE OF OPTIONS

Given the changes competition has already brought to the industry, what additional modifications to current regulatory and corporate structures are needed to further reduce costs, support new and improved generation technologies and better allocate risks?

There are many possibilities. The range of options is bracketed by two models. At one end, is a fully competitive, deregulated wholesale market. At the other is a model that includes some combination of IRP, competitive bidding and PBR. Either way there are prerequisites and primary factors regulators need to consider.

Model 1 - A Fully Competitive Wholesale Market

A fully competitive wholesale market is one in which generation is completely deregulated. Cost recovery for generation is set by market prices not by regulation. The delivery end of the business — transmission and distribution — does not change. These services remain regulated monopolies and operate under regulatory oversight. In a wholesale competition framework, customers continue to be served by their local utility (or DISCO). The utility is a delivery service utility that first purchases (or generates) then delivers power. Regardless of their power supply choices, DISCOs are permitted to charge no more than market prices for generation.

Model 2 - A Combination of IRP, PBR, and Competitive Bidding

The second option stops short of a fully competitive model. It relies on IRP to balance cost versus risk tradeoffs and to determine when new resources are needed to maintain reliability. Competitive bidding is then used to acquire these resources at the lowest cost. Finally, PBR-style regulation determines cost recovery and provides stronger incentives for efficient utility operation.

Prerequisites

The prerequisites for both models are similar:

> **Transparent market price.** Because DISCOs are permitted to recover market prices (model 1) or an amount established in a PBR (model 2), a readily available, and transparent market price is needed. This may be a power pool's spot price, a blend of spot and future prices, a benchmark price from contracts signed by other utilities or some other measure.
>
> **Free from market power.** Whatever measure of market price is selected, it must be free from manipulation by regulators, generation companies (GENCOs) or DISCOs. There must be enough buyers and sellers to be sure none have an undue influence on price, opportunities for collusion are minimized, and true market clearing prices are produced.

Market power issues can be resolved either through structural changes to the industry or through regulatory intervention to remove the incentive to exercise market power (See Market Power Box). For example, one way to address horizontal market power, where a GENCO has too great a share of a given region's generation, is to place some or all of the generation under a PBR-style contract

Market Power Issues
Vertical market power can be exercised when the same entity owns or controls generation and transmission. The risk is that monopoly access and pricing for use of transmission could limit competition in the generation market. The structural solution is divestiture of generation or transmission. The regulatory solution is to closely regulate all access and pricing terms. The complexity of efficient transmission pricing makes the regulatory option easier to articulate than implement. Vertical market power may also limit the types of services offered to the customer. For example, energy efficiency could suffer if generation becomes fully competitive, but the utility remains vertically integrated. By reducing the demand for electricity, efficiency efforts lower the market price for generation and diminish profit. If the delivery and generation company are one in the same, there is absolutely no economic incentive for making energy efficiency investments. Even cost-effective energy efficiency would reduce the profits of the unregulated generation side of the business. If, however, the distribution company is a stand-alone company that buys generation in the competitive market, an investment in energy efficiency will create value and is, therefore, more likely to occur. Self-dealing refers to the possibility that customers of integrated utility monopolies could be forced to subsidize investments in generation or other competitive markets. Preventing these cross subsidies is one reason commissions were created in the first place. Divestiture, severing the relationship between the generation on one side and the transmission and distribution on the other side, eliminates the problem and is the cleanest solution. When buyers and sellers do not fall under the same corporate umbrella, there are no opportunities for self-dealing to occur, this creates the best opportunity for competition to replace regulation. The alternative is to rely on regulation to police potential self-dealing abuses and to make sure competition in generation proceeds unencumbered. This would require commissions to closely supervise all bids where the utility was bidding to itself and to scrutinize carefully all individual transactions between the regulated and unregulated sides of the business. This role of the regulator as policeman will be much more demanding than the types of enforcement roles commissions usually taken on.
Horizontal market power, the ability of generators to influence market prices as a result of controlling a large share of available generating resources, may also limit effective competition. In a competitive electric market, no buyer or seller acting lawfully can influence the market price. The market price will tend to be a single spot market price at any point in time. This means all generators supplying power in a given hour will receive the same price, a price equal to the highest accepted and dispatched price of that hour. If the market is reasonably competitive and efficient, prices will approximate the marginal production cost of the most expensive generating unit dispatched. Excessive concentration of generation means the market price cannot be trusted. In the event it is determined that horizontal market power exists, the same two remedies discussed above can be used. Divestiture of enough of the generating assets will allow for effective spot market bidding competition and restrict the ability of generators to influence market prices. The second remedy would rely on regulation to remove benefits derived from the exercise of market power while hopefully continuing to support efficient decisions.

with customers. This would reduce the incentive to manipulate market prices.

Open access and efficiently priced transmission. Wholesale competition simply cannot exist without equal access to transmission at non-discriminatory and efficient prices. If access or pricing rules prevent or distort purchase or sales decisions, the wholesale market will not function. Transmission bottlenecks that keep power from moving from the site of generation to the site of distribution can create serious price inefficiencies.

The difference between non-discriminatory and efficient transmission prices can be seen in the UK. The UK has non-discriminatory transmission prices (all similarly situated generators have the same access and pricing terms), but the pricing is not efficient. A generator whose bid was selected, but due to transmission bottlenecks could not transmit its electricity, does not generate power but, nonetheless, receives payment as if the plant operated. Because the generator gets paid for not supplying power, the wisest thing from a generator's point of view is to site a plant on the wrong side of the bottleneck, submit a bid, run the plant only when the transmission system can handle the power but collect a check whenever the bid is accepted. This is clearly an inefficient result.

Regulatory and Other Considerations

There are a number of regulatory and public interest considerations that influence the choice of models.

Each model is likely to lead to very different resource mixes. In both wholesale models, customers are captive and continue to be served by the same DISCO regardless of the wisdom of DISCO's resource choices. Each model therefore includes a mechanism to protect consumers and to discipline resource selection.

In model 1, the protective measure is to limit DISCO cost recovery to market prices for generation regardless of generation costs. For regulators to take this position, DISCOs must be allowed to freely choose how they acquire power. Choices range from signing long-term, fixed price contracts for 100 percent of need to relying exclusively on spot purchases.

If a DISCO opts only for long-term contracts, it will face the full risk (positive or negative) of market prices being above or below contract prices. Experience with long-term contracts suggest outcomes ranging from bankruptcy to obscene profitability are possible. The critical question for regulators and policy makers is whether a DISCO, with its captive customer base, would truly be free to take these risks

Risk averse DISCOs are much more likely to opt for full reliance on the spot market and hence face no generation related risk. (Its generation costs and revenues are always market price.) Customers, meanwhile are fully exposed to the price volatility of spot prices. A key question for regulators is whether the resulting price volatility and balance of long- and short-term resources are acceptable to impose on captive customers.

Under model 2, consumer protection is provided through the combination of PBR, IRP and competitive bidding. The balance between spot, short-term and long-term supply options is a decision shared by the DISCO and regulators. Regulatory assessment of the public interest will rely on IRP or some similar analysis cost and risk. DISCO cost recovery will depend on the PBR, not market prices. This means customers will bear some of the risk that prices may deviate (up or down) from spot market prices. The precise formulation of the PBR will be influenced by the mix of resources selected. PBR can be designed to provide incentives for efficient plant operation that are nearly as powerful as full deregulation. Indeed, the strongest proponents of competition suggest PBR be used for existing generation as a means of addressing market power concerns without resorting to divestiture.

Will a market-based system of reliability be publicly acceptable? Under model 1 (and under any direct access model), price becomes an integral part of how reliability will be maintained. When capacity is short, market prices rise and as prices rise, demand drops. A risk-averse DISCO will tend to allow high market prices to balance supply and demand rather than build or enter into long-term contracts for new supplies, even if the new plant is expected to be the least-cost over the long term. Generators, who have historically built plants on the financial foundation of long-term contracts, will now build based on current and expected spot market prices. An important question is: how high will prices have to rise for generators to decide to build? No matter what this price is, the shorter time horizon will favor small, low capital cost plants, such as gas-fired turbines.

Under model 2 the level of reliability is a factor in the IRP process. Regulators, with input from all stakeholders, can balance dependence on price-induced demand reduction, load management and generation options.

EXPANDING THE SCOPE OF WHOLESALE COMPETITION

There remains the question of what are the best steps to take in the next few years to move to a more workable wholesale (or retail) competitive structure. One option for the transition is to move from cost-of-service regulation to PBR, IRP and competitive bidding (model 2). This option is not likely to please customers who are pushing hard for market prices. The pressure from these customers, often large, industrial customers who are important players in a state's economy, may require commissions to make many case-by-case decisions, each of which demands finding the line that, on one side, discourages uneconomic bypass but, on the other side, does not restrict competitive supply. Commissions, for instance, will be under constant pressure to judge just how serious a customer's threat for leaving the state or self-generating really is. This partially deregulated period promises to be demanding. While PBR schemes may help, they will not resolve the difficult cases regulators can be expected to face. (See chapter on Flex Rate and Rate Design Solutions.)

Deregulated market based generation will give generation firms stronger incentives to cut costs than the existing monopoly structure provides to utilities. However, this does not necessarily mean costs will be lower. On the one hand, competitive firms will certainly find additional ways to cut costs, although it impossible to predict exactly much. On the other hand, they will face higher capital costs because stockholders will expect significantly higher rates of return from them than they require from monopoly utilities. In addition, competitive firms generally are much less heavily leveraged (that is they rely more on equity financing and less on debt) than traditional utilities[1]. After taking the effects

[1] An exception can occur if the generation company has a long-term contract to sell its output to a traditional monopoly utility. Qualifying Facilities, which had such contracts, were often even more heavily leveraged, typically in the range of 80 percent debt, than traditional utilities with roughly 50 percent

of income taxes into account, equity financing is roughly twice as expensive as debt financing, even for traditional utilities. For competitive firms, this effect will be magnified by the higher rates of return to stockholders.

Increases in financing costs are potentially quite large[2]. For example, if deregulation causes an increase in equity financing from 45 to 65 percent of capital, and if the cost of common equity rises by three percentage points, the financing cost would increase by more than one-third. Competition would need to produce construction and operating cost savings of well over ten percent simply to offset such an increase in financing costs. Larger operational savings would be necessary to produce overall cost savings.

Lastly, changes in industry and market structures that need to occur to achieve a fully competitive wholesale system cannot be made by state regulators alone. Because changes of this magnitude are essentially political decisions, all stakeholders — federal and state regulators, utilities and customers — will be involved. This suggests there is still a great deal of ground to cover and a need for all parties to work together closely.

---

of debt financed.

[2] For example, see the Wisconsin PSC "The Future of Wisconsin's Electric Power Industry, Volume I."

Retail Competition

Retail competition breaks the link between customers and their local utility by removing the requirement that utilities acquire generation resources on behalf of their customers. The historic utility obligation of insuring that adequate generation is available to serve all customers (which remains in the wholesale competitive model) is replaced by an obligation to connect all customers to the utility's distribution system. Thus, customers continue to be hooked up to the same set of wires, with delivery of energy purchased as a separate monopoly service from the local utility.

By removing the obligation to serve, all customers have the responsibility of contracting for their own power supply. Contracts may be entered into directly with one or more generators or indirectly through aggregators, marketers or brokers. Regardless of who the customer selects, payments are made based on mutually agreed upon prices and terms. The only obligation placed on generators is to fulfill the contractual commitments they have made with customers

WHY RETAIL COMPETITION?

The chapter on wholesale competition describes the reasons people believe wholesale competition in general, and a fully competitive wholesale markets in particular (described as model 1 in *Wholesale Competition* chapter) can lead to significant productivity gains and lower generation costs. Most proponents view retail competition as a simple step beyond a fully competitive wholesale market; a step which adds financial contracts between customers and generators, aggregators, brokers or others.

This chapter assumes a fully competitive wholesale market is in place and examines the unique issues raised by the addition of retail competition. The two most common reasons given for supporting full retail competition are lower rates and customer choice.

Lower Rates

The promise of competition is that it will be more effective than regulation at controlling prices. Lower prices can be achieved in two ways. However, only one way ― improved efficiency ― is consistent with public policy and as a result is universally desired. The second option removes from rates all or part of current costs in excess of competitive prices. Doing this simply shifts costs formerly shared by all customers to a smaller number of customers and/or utility shareholders. Increasing the financial demands placed on remaining consumers and/or utility shareholders assures that this method is not universally endorsed.

Customer Choice

With or without reduced costs, there are a range of benefits that can be derived by increasing customer choice. These include consumer freedom to choose between competing suppliers, environmental impacts, financing schemes and billing options. In other cases, customers have unique power service requirements, and they believe they can do a better job than the utility in locating power supplies to meet their needs. These arguments suggests retail competition will offer some advantages.

ISSUES RAISED

Encouraging Economic Efficiency And Discouraging Uneconomic Results

The direct economic advantages of retail competition accrue when customers are able to buy or build a resource at a cost lower than their utility would spend for the same resource. There is a risk, though, that customers could make a decision that appeared economic but was not.

Uneconomic decisions will occur if customers are given a choice between purchasing from the local utility at existing rates, which include significant sunk costs, or purchasing from alternative suppliers and avoiding sunk costs. If the primary benefit derived from changing suppliers is avoiding sunk costs, rational customers will be encouraged to make decisions that are irrational from a societal perspective. If they can avoid sunk costs, they will happily choose suppliers that have higher marginal costs of service than their existing utility. In this case, the decision to choose a new supplier, while favorable for the departing customer, would be uneconomic and inefficient for nearly everyone else.

The role for commissions is to establish conditions that support economic decisions while discouraging uneconomic purchases that will result in inefficient outcomes. The best way to do this is to assure there are no choices that allow a customer to avoid paying sunk costs. This can be done by collecting sunk costs in a competitively neutral and non-bypassable fashion. A carefully-designed retail wheeling rate can accomplish this. (See chapter on *System Benefits Charge* and *IRP and Competition* chapter of the 1994 Workbook.) Access fees, exit fees or some combination of charges could also work.

Stranded Costs

Stranded costs, or more accurately strandable costs, are found where retail electricity prices are above marginal costs. Stranded costs are an issue in wholesale or retail competition but are a particular problem a retail competition setting. The consequence of any customer leaving the utility is that the utility's revenues will go down by the full retail rate while the utility costs will go down by the far smaller marginal cost. The utility's stranded cost is the difference between the drop in revenues and the drop in costs, minus revenues collected for retail wheeling services. That stranded costs are reduced by the amount of any retail wheeling rate further emphasizes the need to carefully consider the level of the charge.

Stranded Benefits

Not just sunk cost are at risk of being stranded in a competitive world. Public benefits run a similar risk of being abandoned. Electric utilities provide a number of vital services beyond the generation and delivery of kWhs. Energy conservation, development of renewable resources, R&D activities and the provision of services to low-income customers have been an integral part of electric utility services and have collectively produced millions of dollars of efficiency savings, a cleaner environment and the assurance of universal electric service in an economy which is highly dependent upon electricity. A price-based world jeopardizes support for each one of these.

Any restructuring effort should make sure these benefits are not allowed to be lost in a competitive electricity market. This is discussed more fully in *System Benefits Charge* chapter.

Risk And Resource Diversity

For better or worse the electricity in the United States is produced by a mix of resources. There are different fuel sources and different technologies; some capital intensive and some are not. The economic principle guiding acquisition and construction decisions has been to locate technologies with the least-cost over the life of the plant. Little, if any, weight has been given to relative mix of operating (fuel) cost versus capital cost. This has been possible because power plants have been built based on the financial underpinning of long-term contracts. In the case of utility-constructed plants, the contract has been the implied contract created by the traditional obligation to serve. Non-utility plants have been financed based on long-term contracts with financially secure electric utilities.

Removing the obligation to serve and freeing customers to buy from any supplier will mean long-term contracts will become rare. Experience abroad confirms consumers focus on short-term (less than five years) commitments, not the 15 - 30 years traditionally used by the utility industry. This change in financial underpinnings will certainly affect on the types of plants that get built in the future.

Retail competition is likely to favor low capital/high operating cost generating sources for two reasons. First, generating companies will be unregulated, competitive firms that will tend to operate under shorter planning horizons than regulated utilities. Second, since the firm's customer base will be free to change suppliers with little or no notice, companies will try to minimize their risks and keep their costs from rising above prevailing market prices. Because gas prices are likely to determine market clearing prices for electricity, the market risk — the risk that a generator's cost will be different than market prices — will be minimized by relying on gas-fired combustion turbines and combined cycle units. This will be the case even if non fossil-fired, renewable resources are less expensive over their lifetime.

Phase-Ins

Adoption of retail competition will, of necessity, involve a transition period. During this period, a number of details will need resolution. Regulatory commissions may want to explore the following issues.

Does retail competition require new metering? Who bears the cost of new meters?[1] Will residential and other small customers be allowed to have retail access without new metering? Will new municipalization or franchise auctions be the fairest way of implementing retail access?

Will large customers have retail access before other customers? Will the phase-in be

[1]Norway has responded to these potential issues in a manner that creates effective retail competition for all customers without requiring individual time-of-use meters. See *Guidelines for Metering and Settlement*, November 1994, Norwegian Water Resources and Energy Administration.

implemented pro-rata across all customer groups? Will initial access to the retail market be auctioned or allocated in some other manner?

Will retail access be implemented with or without a default choice? Will there be a provider of last resort? Will customers who once elected retail access be permitted to return to utility-provided service and if so under what terms? Will the terms for return be legally or politically enforceable?

Stranded Costs

Today's regulators, particularly those in states with high electricity prices, face calls for increased competition in the electric utility industry and a very full plate of new issues. Deciding what kind of competition makes sense and how to get there is an enormous challenge. Often, the debate is over whether retail competition — allowing customers to shop for generation — provides any advantage over wholesale competition among generators. But first there is a more basic question.

At the heart of nearly any competitive option is the problem of stranded costs. In general terms, stranded costs represent the difference between today's retail electricity prices and the current market price for power — a difference that is very large in many states. What stranded costs are and how they should be handled lie at the center of any discussion of restructuring the electric industry.

WHAT ARE STRANDED COSTS?

The primary concern at this time is not about costs that **have been** stranded but about costs that are **at risk** of becoming stranded in the future. Therefore, the term strandable, as opposed to stranded, better describes this issue. With a few exceptions, nearly all of these costs are currently in rates. Whether or not a strandable cost actually becomes stranded depends on actions that utilities, customers and regulators take. Many of the issues before regulators today involve decisions that may create stranded costs. It is only in cases where stranded costs are created that regulators must decide what they are and who pays. The shareholders? The customers? Which customers?

Breaking down the definition of strandable costs makes the concept easier to grasp.

Step 1
By defining strandable costs as the maximum amount of money the utility is now collecting that is at risk, they can be calculated quite simply as the difference between what the utility now charges a customer **minus** any cost it avoids if the customer is no longer served.

Example 1: Assume an industrial customer pays the utility $1 million per year for service. If the customer moves the factory to another state, the utility's annual revenues go down by $1 million. But the utility's costs also go down. Assuming fuel savings reduce the utility's costs by $600,000, $400,000 per year would be left stranded. It will be up to regulators to decide how these costs should be recovered.

Step 2
Suppose the customer does not move the factory but instead takes advantage of retail wheeling and chooses a different supplier. Because the customer continues to be connected to the utility, she will continue to pay some reasonable charge to use the local utility's transmission and distribution system. Now the strandable costs are the difference between what the utility currently charges a customer **minus** any cost it avoids if the customer is no longer served **minus** any charges for residual services, such as transmission and distribution.

Example 2: If the same customer leaves the utility through retail wheeling and pays the utility $100,000 per year for transmission and distribution (T&D charge), the strandable cost drops to $300,000. (The original $1 million **less** the combination of fuel savings and transmission and distribution services.) Regulators will be asked to decide who will pay for these costs in the future.

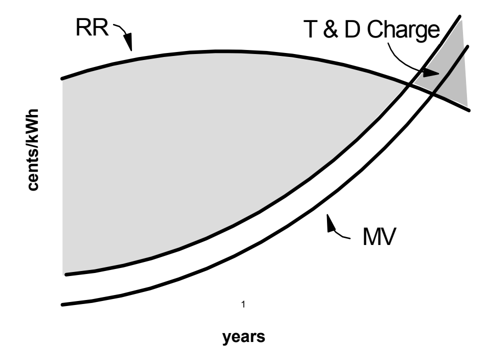
Step 3

The element of time, unfortunately, makes the second definition incomplete. The definition is correct and reasonably accurate for the first year. But what about years two, three...? Adding the element of time not only leads to the full definition of strandable costs, but it also exposes its most difficult issues. These are the uncertainty of calculating the number and the risk of getting the number wrong. By taking the time element into consideration, this third definition defines strandable cost as the present value of the difference between what the utility would have charged the customer over time **minus** any cost it avoids over time if the customer is no longer served (this is also the market value of power over the same time period) **minus** any ongoing utility charges for residual services.

Example 3: The customer is a retail wheeling customer now and for the next 20 years. By using the equation from example 2, a yearly stranded cost determination can be made. The shaded area of the graph 1 shows these year by year stranded costs, both positive and negative.

An examination of what the lines represent illustrates the complexity of calculating stranded costs over a number of years.

Graph 1: Changes in Strandable Cost Over Time



Revenue Requirements (RR)

The most familiar part of the graph, the line labeled RR, is the revenue requirements per kWh. This line, as will be seen in subsequent graphs, is the same as the average retail rate. Two issues arise when estimating this line into the future.

1. Forecasting load, fuel costs, interest rates, inflation and all of the other parts of the revenue requirement is inherently risky. Even the best crystal balls are never perfect.

2. Forecasting revenue requirements means estimating costs associated with today's service that are not yet in rates. Examples include the future costs of existing power purchase commitments, deferred costs of all sorts, the costs of unfunded nuclear decommissioning, waste storage and salvage value of plants and sites. If today's customers remain with the utility, they would be expected to share these costs and revenues at a later date. By leaving, their share of these unknown costs and revenues are strandable.

Market Value (MV)

The line labeled MV looks familiar because it has the same shape and level as avoided cost projections. This is not a coincidence. For all practical purposes, market value and avoided cost are the same. However, while these terms can be used synonymously, market value has a very different use than avoided cost. It is this use that makes the task of determining market value and the consequences of getting it wrong much more daunting.

1. Avoided cost typically places a value on small additions to the existing generation system. For many policy choices now under consideration, market value for estimating strandable costs sets a value for the entire system — both existing and new generation. If the avoided cost for a 50 MW resource addition is off by $1/KW, the mistake will be a contained one. But when calculating strandable costs, the impact of the same error, because it applies to the entire system, will be much greater.

2. With avoided costs, it is possible to limit consideration to resource options within the utility's control. Market value calculations, on the other hand, require forecasting a value for generation in the context of a much larger, deregulated regional market. If the market mechanisms needed for a regional generation marketplace existed, (power pools, open access transmission and structural reforms that eliminate affiliated transactions or market power), these forecasts would be difficult enough. However, since these market mechanisms do not exist, market value forecasts are made with very limited information and understanding.

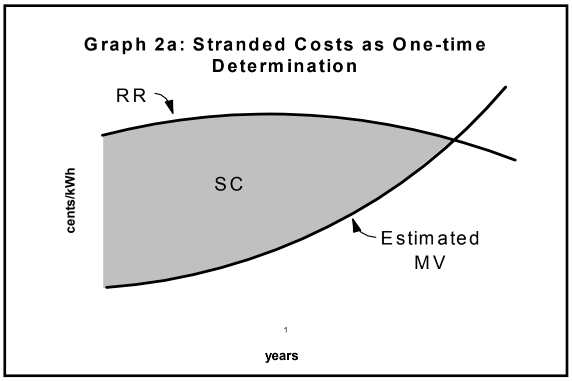
Stranded Cost (SC)

The California PUC's first attempt at defining stranded cost revealed the enormity of the risks associated with the policy options under consideration. In its original vision (the "Bluebook'), the California Commission proposed a policy course which included identification of strandable cost as a first step toward deregulating generation and giving all customers direct access to generation priced at market value. To do this, they proposed a regulatory proceeding that would quantify stranded costs and allow utilities to recover the quantified amount through competition transition charges (CTC). The CTC would be calculated based on the commission's best estimate of stranded cost (the shaded area), including its estimate of the market value of generation resources.

Consider what happens if the actual market value — the price customers pay for electricity — turns out to be different than the commission's original estimate. The following sequence of graphs shows what can happen.

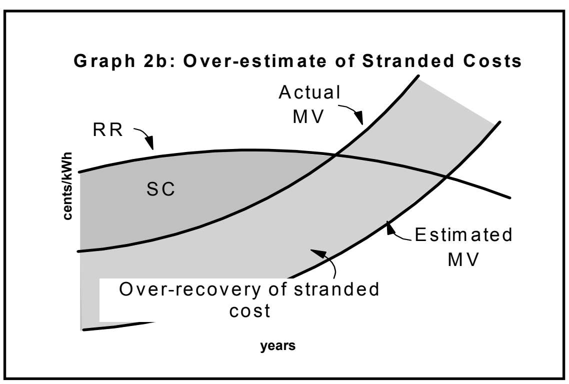
The first graph, 2a, shows the SC that would be the basis of a one-time determination of the CTC.
Graph 2b shows what happens if, after the CTC is determined, gas prices rise higher than expected. Market value rises significantly, revenue requirement (that is the gas-fired portion of the utility's fuel mix) rises very modestly and stranded costs are essentially eliminated. (Note that for the purpose of clarity, this illustration shows an unchanged RR line.) But under California's

original vision, the original CTC remains, and the customer pays the higher market price. In other words, customers pay the



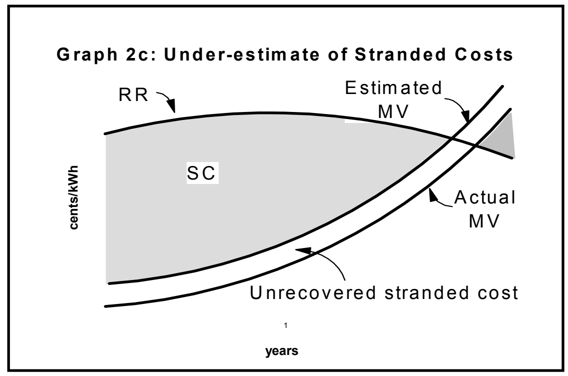
double-shaded area twice, first in the CTC, then in their power purchase.

Graph 2c shows what happens if gas prices fall below forecasts. Customers pay a low market price for generation and a CTC that leaves some stranded costs (unshaded area) uncovered.



POINTS NOT TO FORGET

These examples illustrate two fundamental points. The first is that because there is a great deal of uncertainty surrounding strandable cost determination, even the best and most unbiased attempts will produce a number that will be wrong. What is not known is by how much and in what direction the error will fall. (For a medium to large electric utility, errors of several $100 million are possible.) Second, how customers, shareholders and utilities are exposed to the consequences of errors in stranded cost determination depends entirely on the form, pace and scope of policy choices made by regulators.



System Benefits Charge

Cost-effective electricity conservation, the development of renewable resources, programs for low-income electric customers and supportive research and development have been an integral part of the services delivered by most electric utilities. Without some mechanism to preserve these desirable features of the current electric utility system, they could become inadvertent casualties of the transition to a more competitive electric utility structure. Implementing a system benefits charge will preserve services in a competitive environment and doing it now will help speed the transition.

WHY DO REGULATORS NEED TO WORRY ABOUT SYSTEM BENEFITS?

Electric utilities provide a number of vital services beyond the generation and delivery of kWhs. The reduction of long-run resource costs through energy conservation, the development of renewable resources and research and development activities represent important utility investments that many states have made over the past fifteen years. Over an even longer time period, the provision of services to low-income customers such as special payment plans, cautious winter disconnection policies and home weatherization services have been an integral part of electric utility services. Collectively these public benefits produce millions of dollars of efficiency savings, a cleaner environment and the assurance of universal electric service in an economy which is highly dependent upon electricity.

In yesterday's fully regulated industry, these benefits were fairly easy to deliver. But in a competitive electricity market, their continuation is not a given particularly if a competitor can gain an advantage by not including one or more of these services. Adopting a system benefits charge today, no matter what course a state takes, will aid policy makers' move to a more competitive environment in two ways. First a charge can assure services are funded in a way consistent with a competitive future. Second, implementing industry change will move along more swiftly if the public is assured that these important benefits are not at risk.

WHY ARE THESE SERVICES AT RISK?

The competitive generation markets envisioned by most proponents of restructuring will exchange cost-of-service cost recovery for power plants with market prices. It will replace utility obligation to build or buy power supplies to minimize long-term costs (15 to 30 year planning horizons) with obligations based on short-term contracts (0 to 5 years) with customers or distribution utilities.

Summary of NARUC Resolution on Competition, the Public Interest, and Potentially Stranded Benefits

. . . **WHEREAS,** the laws and traditions of electric utility regulation have long recognized the electric industry as a critical element of national infrastructure greatly affected with the public interest; and

WHEREAS, the franchise system of regulation has encouraged electric utilities, pursuant to state laws, to secure important public benefits in the provision of utility services, including:

- system reliability and fuel diversity;
- responsible management of the environmental impacts of electric generation;
- the promotion of systematic investment in energy efficiency, thus improving the nation's energy security and lowering energy costs to the nation's economy;
- innovative rate designs that have served national and state objectives in such areas as rate stability, equity, economic development, and meeting the specific needs of low-income customers;
- a system of support for research and development for the electric industry;
- investments in commercialization strategies to speed growth in markets for renewable energy technologies. . .

WHEREAS, these widespread public benefits could be undetermined or lost unless integrated into new proposals which are being developed for a more competitive marketplace; and

WHEREAS, it is the responsibility of state and federal electric utility regulators to assure that these vital public benefits are not "stranded," but are well served in new electric industry structures and in the transition to them; . . .

Now therefore be it

RESOLVED by the National Association of Regulatory Utility Commissioners at its 106th Annual Convention in Reno, Nevada, that a fundamental responsibility of state and federal electric utility regulators in this transition period is to assure that vital public interest and established public benefits will be preserved in any restructuring of the electric utility industry; . . . and be it further

RESOLVED that, in their individual deliberations over the restructuring of the electric industry, state and federal regulators are encouraged to establish the criteria by which alternative proposals are to be judged, and that these criteria should include: reliability and fuel diversity, environmental protection, energy efficiency, equity, economic development, the needs of low-income customers, and research and development; . . .

November 1994

This type of market increases the risk and hence decreases the likely investment in capital intensive, long-lived resources and in renewables. It also means that expenditures on research and development — with an inherently long payback period — and expenditures on low-income services will also have a much smaller chance of being provided in an unregulated world. Even if careful shaping of market structures is able to assure the continuation of some or all of these services, many are already being scaled back and, in some cases, eliminated in the current transition from regulation to markets. Utilities fear every dollar spent on these services will probably not be recovered or will certainly place them at a competitive disadvantage in the future.

No matter how well these services might br delivered in a mature market, the transition period poses a most serious challenge.

Looking past the transition period, hopes are high that newly competitive electric markets will deliver both well-established and new services at the lowest possible prices. The question is to what extent can mature markets provide energy efficiency, renewables, R&D and low- income services. The general experience with the deregulation of other major U.S. industries such as telecommunications, gas and airlines gives grounds for both hope and pessimism. Electricity markets are no more likely than any of these industries to deliver low-income services since these services offer no profit-making opportunities. Whether or not markets will deliver energy conservation and renewable resources is less clear, but it is fair to predict that a market focused upon short-term, spot prices will choose less cost-effective energy efficiency and renewable resources than would a long-run resource plan for a monopoly utility.

Markets for renewable resources may emerge in retail competition as individual customers are given the opportunity to make resource decisions. However, one can only speculate on the size and strength of customer demand for renewable energy resources. Energy conservation, on the other hand, has long been available to customers, but the market has often failed. In fact, it could fairly be said that it was this failure on the part of consumer markets to deliver cost-effective energy conservation that left such a large resource available for utility development in the first place.

As regulators have already learned with the deregulation of many telecommunication services, the transition period to fully functioning competitive markets can be long and uneven. In anticipation of a similar route in the electric industry, the benefits of the current system must not be stranded.

THE SYSTEM BENEFITS CHARGE: PRESERVING BENEFITS IN TODAY'S STRUCTURE ...AND INTO THE FUTURE

A system benefits charge can be used to provide the current level of public benefits while markets are given a chance to develop. Like electric companies, regulated telephone companies had a history of providing societal benefits such as universal service for low-income and physically-impaired customers, and, more recently, 911 emergency calling; a service which has much more to do with health and safety than with telephone access. Providing these services in a competitive environment meant funding them in ways in which all consumers paid but which did not tilt the competitive playing field. To do this, today's bills (regardless of the service provider) include a charge of around three percent.

This same approach, at approximately the same amount of funding, can be extended to the electric industry. The size of the charge can be adjusted as it becomes clearer what market forces will provide.

The balance of this chapter looks at how to create a fair and effective system charge that preserves today's benefits without interfering with the development of tomorrow's markets.

What Are The Essential Characteristics?

A system benefits charge can come in many shapes or forms and under a variety of names. Terms such as wires charge, access charge, universal service charge or distribution charge have already been used in connection with such a charge. But, whatever the form or name, two features are essential to making it work. It must be both **non-bypassable** and **competitively neutral**. Placing a charge on the use of the distribution system (distribution applies to both high and low voltage end use consumers) answers both concerns.

It is non-bypassable because the distribution system, for the foreseeable future, will remain a monopoly and will be needed to deliver electricity, regardless of its origin, to virtually every consumer, including large industrial customers who obtain high voltage electricity and municipalization customers. Even most customers who self generate are included because nearly all of them require back-up power which, in most cases, means they too will remain connected to the distribution system. It is competitively neutral because all sellers are treated equally. With the same charge levied on customers no matter who supplies the power, users cannot bypass their share simply by choosing another supplier.

This approach to paying for system benefits is also how utilities' allowable stranded costs should be recovered. In both cases, the goal is to structure the charge so that the desired revenues are generated without encouraging customers to make uneconomic purchasing decisions or choosing one supplier over another. The major difference is that stranded benefits charges are relatively small and fund the ongoing delivery of essential services and new efficient resource investments while a much higher (as high as 50 percent of rates in some territories) stranded cost recovery merely allocates the sunk costs of investments which are, in retrospect, too expensive.

Another advantage of a distribution-level systems benefits charge is that states have the authority to impose them. Despite a continued blurry distinction between state and federal jurisdiction over aspects of restructuring and competition, the Federal Energy Regulatory Commission (FERC) has acknowledged state rate making authority over distribution services. Still lacking is a precise definition of distribution services. Because a system benefits charge must be non-bypassable to be effective, local distribution facilities must either be defined in a way that includes all sales to end users, regardless of voltage level, or FERC-approved charges must mirror state imposed system benefits charges. FERC's Mega-NOPR on Open Access of Transmission and Stranded Costs specifically notes in two places the states' reserved authority to impose a charge for stranded benefits on local distribution facilities.

How Large Should The Charge Be?

A combination of policy making, resource planning and seeing what the market will do will be used to set a spending level adequate to deliver a reasonable amount of cost-effective energy efficiency, renewable resources, R&D and low-income services. A first step is to tally how much is currently being spent to deliver these benefits. Levels in most states range from one to five percent of the average bill. While current spending is a good place to start, if it turns out markets deliver these services at reasonable levels or the services are provided through other means (such as tax dollars), the benefits charge can be reduced accordingly. If, though, markets or other means never adequately deliver these services (as is likely to be the case for low income services), the benefits charge can continue without interfering with the markets that do develop.

Structuring The Systems Benefits Charge

Because these costs are currently being recovered in rates, to the extent that the charge closely resembles existing rate design, there need be little change in equity and efficiency. Keeping the charge in sync with existing cost allocations should enhance public acceptability.

In most jurisdictions, the costs of services to be included in a benefits charge are collected on a volumetric basis ─ generally a kWh but occasionally a KW basis. The more electricity one uses, the greater one's contribution to system benefits. The other choice is a fixed charge which substantially changes existing cost allocation. With all customers paying a fixed amount, smaller customers would be expected to pay a larger percentage than they currently do. This shift would not go unnoticed.

There is a range of legitimate opinions and concerns on this subject. Some argue that since one benefit of a more competitive market system for electricity is prices can reflect marginal costs on as close to a real time basis as possible, any kWh charge in excess of marginal costs will distort the price signal and diminish the overall efficiency of consumption. Others contend that energy efficiency and renewable resources predominantly deliver energy and capacity and hence should be charged on a volumetric basis, just like energy and capacity costs. Proponents of a fixed charge argue that it is not bypassable by those who lower their energy consumption, and it minimizes price distortion.

The choice between volumetric and fixed costs need not be an all or nothing decision. The telecommunications industry, where both approaches have been used at the same time, again serves as a useful model. In considering a melding of both approaches in the electric industry, it would be possible to levy a fixed charge for all customers based upon a minimum standard of use, say 250 kWh, and a per kWh charge for all use above that level. To assure acceptance, care must be taken to make sure any change from the existing cost allocation occurs at a slow enough pace.

Alternatively, the system benefits charge could be charged on a volumetric basis to generators who use the distribution system to reach their customers. Under this scenario, generators would be expected to pass the charge onto customers.

Another consideration is whether the system benefits charge should appear as a separate item on the customer's bill. Listing a separate charge on the bill for any item draws attention and, often, opposition. This is true even if the amount is relatively small.

Whether to break out costs should be decided as part of an overall effort to develop the information needed to support customer choice. Listing benefit charges is only a small part of the overall information that might be important to break out on the customer bill. For example, bills could also show other categories of cost such as transmission and distribution costs and recoverable uneconomic costs.

Who Manages The Money And Provides The Services?

Once money is collected via a system benefits charge, there are a number of places — ranging from the utility to a non-profit or governmental entity — where it can be managed. Dollars will be most successfully spent if there is as little conflict as possible between the purpose of the benefits and the manager's interest. For instance, the profits of utilities with an unregulated generation arm will hinge on the market price of electricity. Because energy efficiency tends to reduce demand and hence market price, the utility will have no interest in investing in energy conservation. In contrast, the same utility will have an interest in assuring that low income customers are able to pay their electric bills.

If the utility interest is at odds with the delivery of a particular service, it may be easier to instead place the responsibility for managing funds in the hands of an independent, non-profit corporation or a government agency. While such a is most apparent for energy efficiency, similar issues could arise for renewables, low-income services and R&D as well. While different management approaches may be appropriate, a practice of keeping financial motives separate from the management of funds for services must prevail.

Regardless of who hold the funds, a market means, such as competitive bidding, should be used to decide who provides as many of the services as possible. Consolidation of services should keep costs low. Already there are national and international models for the delivery of energy efficiency and the acquisition of renewables. Other innovative measures can be found for the delivery of low-income and R&D services.

National And International Examples Of System Benefits Charge

There is a small but clearly growing consensus as to the merits of electric utility system benefits charges in the United States. Both Washington State and Idaho Commissions have approved a system benefits charge to fund DSM for Washington Water Power. In Arizona, utility regulators implemented a system benefits charge for Arizona Public Service Company. The California Commission, which has put forth the most complete vision of retail competition to date has, in both the majority and minority views, preserved funding for public policy goals using non-bypassable charges. The Statement of Principles emerging from Rhode Island and Massachusetts collaboratives on electric industry restructuring recommends a "non-bypassable, non-discriminatory" charge to fund existing special rates, payment programs and protections regarding customer service and shut-offs for low-income customers, cost-effective energy efficiency investments and programs and renewable resources. The Massachusetts Department of Public Utilities has approved these Statement of Principles, and they are under consideration by the Rhode Island Commission. Finally, Wisconsin Electric Power has suggested a systems benefits charge as part of its vision of a restructured industry.

There has been a longer history of system benefits charges in Europe. The City of Oslo, Norway and Oslo Energi levied a volumetric charge beginning in 1982 to establish a capital pool for loans to make investments in energy efficiency. The fund became self-sufficient, and the charge was discontinued after ten years once $149 million was raised. Today, loans from the revolving fund have been made to over 20,000 customers, from all customer classes. The United Kingdom is using a system benefits charge to fund energy efficiency and renewable energy development

CONCLUSION

The system benefits charge is a simple mechanism to continue funding important public benefits that may otherwise be lost in the restructuring of the electric utility industry. System benefits charges can be implemented relatively quickly and easily, which is important during this period of uncertainty and transition. Implementation now preserves the benefits while giving

Washington Water Power
Washington Water Power (WWP) received approval from the Washington Utilities and Transportation Commission and the Idaho PUC in October 1994, for a two-year experimental system benefits charge to provide stable, predictable funding for DSM.

The charge applies to WWP's electricity and natural gas sales and is assessed by customer class. There is a 1.55 percent increase for electricity customers, a 0.55 percent increase for gas customers in Washington and a 0.6 percent increase for gas customers in Idaho. The lower gas assessment matches gas revenues with planned gas DSM expenditures. Actual charges for electricity range from .046¢ to .108¢ per kWh and .097¢ to .197¢ per therm for gas customers. The charges will yield an annual average of $4.7 million for electric DSM and $426,000 for gas DSM. All DSM expenditures funded through this mechanism are subject to a prudence review at WWP's next rate case.

Arizona Public Service Company
The Arizona Corporation Commission approved a settlement agreement between the Arizona Public Service Company (APS) and other parties that established spending targets for renewable resources and DSM programs for each of three years beginning November 1994. APS must file an implementation plan that requires Commission approval and will recover costs through the Energy Efficiency and Solar Energy Fund (EEASE Fund). The EEASE Fund is created by the application of a system benefits charge based on kWh sales, with annual spending targets beginning at $10 million and increasing yearly through the first four years. Of the spending targets, at least $9 million over the three year period must be spent on renewables.

United Kingdom Energy Saving Trust And Renewable Acquisition
The UK government has two system benefits charges. One, levied to help the UK meet its commitment to reduce greenhouse gases, supplements energy efficiency and the other renewable resource development.

For energy efficiency, a fixed system benefits charge of £1 ($1.60) per year is assessed on all franchise customers of distribution utilities. Franchise customers are residential and small commercial customers with a demand less than 100 kW. For an average user, the £1 charge is equivalent to 0.0337¢/kWh or a 0.3 percent increase on an average rate of 12¢ per kWh. Each of the distribution utilities receive energy savings targets and an allowance to implement programs to meet targets. A government corporation, the Energy Saving Trust, was set up to determine targets, allot monies and oversee utility performance. The Trust reviews the proposed programs, verifies the saving estimates and tracks fund allocation to each utility to insure that savings are achieved within budget.

Five percent of the Non-Fossil Fuel Obligation funds renewable resource development. The remaining 95 percent supports existing nuclear investments. The charge is based upon the difference between average pool prices and actual resource costs. The target for renewables is 1500 MW by 2000. As of 1994, 1200 MW were approved for purchase.

regulators time to assess what services are effectively produced through competitive electric markets. There are helpful U.S. and international models to serve as examples for creating and structuring this charge.

Is There a Continuing Role for IRP?

While the details of Integrated Resource Planning (IRP) have varied over time and among states, its universal objective — to minimize the system-wide, long-run cost of electric energy — has not changed. IRP provides a multi-attribute approach to planning that uses public input and explicitly trades near-term costs with longer-term economic and policy goals. This longer economic view is most at risk of being lost (or stranded) in the move to a more competitive industry structure.

IRP planning has allowed utilities and regulators to:

- Evaluate supply (generation and power purchases) and demand (conservation and load management) options on an equal footing.

- Compare the risks of alternative approaches, including the impacts of adopting a higher cost/lower risk plan in favor of a more risky but lower cost plan.

- Understand and evaluate the costs and benefits of resource diversity and risk mitigation strategies.

- Place a value on environmental impacts (either directly and/or through the likely cost impacts of future environmental regulations).

IRP, however, is not just a planning tool. IRP principles are also the basic tools regulators (and others) use to address a wide range of other regulatory issues. For example:

- **Prudence reviews.** IRP methods and analysis tell regulators what a well-managed utility would have done given the full range of information and options at the time. This applies not only to major construction projects but also to other decisions as well, such as the trade-off between O&M investment to improve heat rates versus increased fuel costs or distribution investment versus line losses.

- **Certificate of Need**. The construction of major transmission or generating facilities typically require PUC approval in the form of a certificate of need or a certificate of public convenience and necessity. IRP principles, defining need in an economic context , serve as the foundation of these proceedings. (Least-costly options or resources that cost less than a utility's avoided costs are, by definition, needed.)

- **Rate Design.** Avoided cost analysis, DSM cost/benefit analysis and rate design feedback into end-use forecasts and resource planning are integral aspects of IRP and major factors in rate design decisions.

- **Clean Air Act Compliance.** Regulatory review of utility plans to achieve emission reductions required by the 1990 Clean Air Act Amendments is an example of how a new regulatory issue benefitted from IRP. The question — what is the least-costly way to achieve required reductions — was answered using the analytical framework of IRP.

- **Setting Budgets.** Some states set spending levels for DSM or set asides for renewables. IRP principles and tools are used to set these goals at levels that are both achievable and desirable.

IRP History

Historically, electric utilities have held a monopoly franchise over all retail (final) sales of electricity within their geographic area. In return for this monopoly status, utilities have had two principal restrictions placed on them. They could only charge prices set by regulators to recover their costs, including a reasonable rate of return, and they have been obligated to provide reliable service to all who wished it, generally by building and/or entering into long-term contracts for adequate generation to meet reliability standards. These twin requirements coalesced into a requirement that utilities must perform formal planning to meet future needs. Plans were reviewed by commissions originally in prudence reviews and, more recently, as part of the Integrated Resource Planning (IRP) process.

CRITICISM FOR THE PROCESS NOT THE SUBSTANCE

The substantive IRP principles and application of these principles to traditional and new regulatory issues have evolved over time, do not vary significantly across the country and are rarely the subject of complaints. The regulatory process used to implement IRP, on the other hand, does vary substantially across the states and is frequently the target of criticism, particularly the assertion that IRP is incompatible with competition. The worst of IRP procedures have resulted in protracted litigation culminating in orders to buy specific resources at specific prices and terms based on evidence so old it no longer reflected current conditions. This is certainly neither a desirable nor necessary outcome of IRP principles.

UNDERSTANDING COMPETITION'S EFFECT ON IRP

Predicting just how the electricity market will evolve is impossible. Chapters on *Wholesale Competition* and *Retail Competition* present plausible models. The implications for substantive and procedural aspects of IRP differ under each model, but a few generalizations are possible. The effects of restructuring on procedural aspects of IRP will be far greater than the effects on substantive or analytical aspects. Who will perform IRP? What information will be publicly available? Will there be structured opportunities for public input? These are all examples of areas that may change a great deal. What will not change are the analytical tools used to make tradeoffs between capital and operating costs, identify the value of distributed generation and take account of environmental impacts.

Who is responsible for making decisions will be a key factor in determining how much IRP process will be needed. If consumers, by exercising individual choice, are taking their own risks, the role for IRP will be greatly reduced. But even in a world of full customer choice, some longer-run, IRP-type considerations may be needed to identify society's optimal investment in energy efficiency and renewable resources.

If the decision maker is not the consumer but the local distribution company, an IRP/prudence process will still be needed to protect consumers who will be liable for the decisions made on their behalf.

The greatest changes for IRP occur under a model of full wholesale and retail competition. This model includes the following features:

- New (and perhaps existing) generation is fully deregulated, with the price determined by market forces, not regulators.

- The wires aspects of the business — transmission and distribution — remain monopolies. To the extent that wheeling is permitted, both transmission and distribution become common carriers.

- Market mechanisms replace the obligation to serve and concomitant minimum reserve requirement for maintaining generation reliability. As demand begins to approach available supply, both transmission and distribution become common carriers.

- Vertical disintegration of the industry will occur either through divestiture or, if that proves impossible, through functional and regulatory separation of the business into competitive and regulated monopoly components.

- All customers have direct access.

The main IRP process changes under these models would be:

- Public hearings would no longer be the method used to obtain public input. Instead, public opinion would be exercised though individual purchasing decisions. To make decisions, public information requirements would be met by placing minimum information or disclosure requirements on competing sellers. Public input would also be available in political and legislative forums.

- Much of the information now used for planning would be considered confidential trade information and therefore would no longer be available.

- Avoided cost data would be replaced by bids and market prices.

Substantive aspects of IRP would also change:

- The typical 15 or 20 year planning period and associated period over which financial commitments are made will be shortened substantially. Experience here and abroad suggests that customers will make contractual commitments for one or two years and occasionally as long as five years. This will have a strong influence on resource additions by favoring low capital cost options.

- Discount rates used in economic analysis will increase significantly due to the increased risks of a competitive market.

- Factors such as risk, uncertainty and diversity will not be addressed in a regulatory context. Instead these factors will be dealt with by customers through insurance, hedging contracts, etc.

- Environmental and other externalities will be considered only as reflected in individual customer decisions.

- Distribution IRP will be largely unaffected.

The adoption of this model, together with the associated changes in IRP, will produce significant changes in the future resource mix, rate design and environmental performance. For reasons explained in more detail in other chapters, the combined effect of these changes include the following:

- A substantial decrease in investment of resources with relatively high capital costs and low operating costs. This includes DSM, renewables and more traditional, large baseload facilities.

- Reliance on gas-fired facilities for the vast majority of new power plant investments.

- Changes in rate design moving in the direction of declining block rates (tail priced near marginal cost) which significantly reduces customer and ESCO (Energy Service Company) installed DSM.

Other aspects of the change to a fully competitive wholesale and retail market include:

- Substantially increased price volatility
- Loss of service to low-income consumers
- Reduced spending on R&D

Thus while increased competition in the industry will produce some beneficial outcomes, namely cost reductions, improved customer choice and service innovations, there will be many undesirable impacts as well, some of which are probably intolerable. Using IRP principles, the undesirable effects can be avoided, without forgoing competition and its benefits.

THE FUTURE OF IRP

To be publicly accepted and successful, a fully competitive model will provide for what have been identified as system benefits ─ DSM, renewables, R&D, universal service, environmental improvement and resource diversity. There is wide agreement that these could be funded using a competitively neutral, non-bypassable system benefits charge, a resource portfolio requirement, a performance based regulation (PBR) specifying resource obligations or some combination of the three. Each of these approaches require an initial determination of what costs and risks over the long run. IRP investment is needed to best minimize society's principles provide the only rational way to inform policy makers' judgement on these issues.

If competition does not develop adequately to protect electricity consumers, IRP retains another important role. If there are not enough competitive suppliers, or if some suppliers hold inordinate market power, the price of electricity generation may be excessive. An electricity market stuck somewhere between a monopoly and fully competitive market will need a continued oversight by way of IRP-based prudence reviews.

A second example of a less than fully competitive model is one where customers remain captive to their local distribution utility, but the distribution utility has an unregulated financial interest in generation. The distribution utility would have the financial temptation to overcharge customers for generation. In either case, IRP can continue to serve as a useful tool to protect customers against monopoly abuse.

CONCLUSION

Competition can beneficially replace some of what is now accomplished through regulation. Parts of the industry, however, cannot be deregulated and even the potentially competitive parts of the business will not be competitive for some time. The role and application of IRP will evolve as the industry evolves. Regulators should not abandon IRP, but rather should focus on IRP principles and apply them to the parts of the industry that will, by necessity, remain subject to regulation.

Avoided Costs and Market Prices

Market prices are, among other things, a measure of the value to society of a particular good. Markets place a value on a bushel of wheat, a pound of lobster or, increasingly, on a kilowatt-hour of electricity. Avoided costs, as used in the electric utility industry, are a measure of the value of a kilowatt-hour to an individual utility[1]. Avoided costs are analyzed by looking at the decrease in costs a well-managed utility would experience if it were offered electric energy for free.[2]

For a well-managed utility, market price and avoided cost will become identical. To minimize its costs, a utility must constantly know the value to it of electricity — the avoided cost — to trade intelligently in the market. If the avoided cost at a given point in time for a spot electricity purchase is 2¢ per kWh, and the market price is 1.5¢, the utility will buy electricity in the market until its avoided cost is reduced to the market price. Conversely, if the market price is 3¢ per kWh, and the avoided cost is 2.5¢, the rational utility sells to the market until its avoided cost has been driven up to 3¢.

This simple example masks an important complexity. Avoided cost and market price will tend to be the same for a given product, but the value of electric energy can vary dramatically depending on the nature of the transaction. Value can changed significantly and is dependent on such factors as when the electricity is delivered, the duration of the contract, and who bears various risks[3]. Care must be taken not to fall into the trap of assuming market price for one transaction will have the same value for all transactions. Knowing the market price of a one-year, firm energy purchase is 3¢ does not automatically make 3¢ an all-purpose avoided cost, suitable for evaluating all other possible purchases. It simply makes 3¢ the correct yardstick for other one-year, firm energy purchases.

In this country, most competitive bidding for power is for long- or medium-term contracts for the delivery of capacity and energy, usually from a specific power plant. The product offered in each bid bundles many characteristics, including plant location, contract terms and allocation of risks and obligations. If the details of different, long-term proposals vary significantly, bid prices cannot be directly compared. Instead the purchasing utility performs an avoided cost analysis, IRP or bid evaluation to identify the economic value or worth of each proposal and selects bids where the worth to the buyer (or the consuming public) exceeds the price.

---

[1] A chapter on what is entailed in properly determining avoided cost was prepared for RAP's 1994 Workbook and is included as a reference at the end of this chapter. This chapter is limited to describing the relationship between avoided cost and market prices.

[2] Avoided costs can be equally well defined as the decrease (increase) in cost resulting from a specified decrease (increase) in customer demand.

[3] There are an almost infinite number of ways the risk profile of a transaction might be structured. A fixed price, take-or pay firm purchase carries with it the risk future energy prices will be low ,and costs will be stranded. On the other hand, a unit purchase, where the buyer pays fuel and O&M costs, reduces the risk to a generator but opens up other risks, such as fuel price escalation, operational problems at the plant and future environmental costs.

It is tempting, but wrong, to believe a wide range of power supply options can be evaluated against a single price. Neither market price nor avoided cost, whether derived administratively, through bidding or via some combination of the two, yield a number which can serve as a single benchmark for comparison of different products.

The following price factors influence the worth of a given power supply:

- Dispatchability, minimum load, ramp rate, start-up cost and forced outage rate
- Length and scheduling of planned maintenance
- Contract duration
- Impact on transmission costs and losses
- Impact on required reserve margins

Other important factors, generally referred to as non-price factors, are more difficult to quantify. These include:

- Extent of front-loading
- Impact on fuel diversity
- Security and performance terms
- Contingency, buy-out, deferral and cancellation provisions
- Developer's experience
- Allocation of financial and operating risks
- Cost of future environmental regulations

These factors, individually or in combination, can have a significant influence on the value of an individual proposal.

For example, the receipt of two bids for 15-year supply contracts, one at 5¢ per kWh and the other at 6¢ per kWh, does not mean that the utility's avoided cost is 5¢ or that the 5¢ bid is necessarily preferable. The bid price alone does not supply enough information to decide which bid, if any, should be selected. The 5¢ bid — perhaps a wind farm that produces power mostly during off-peak periods — could be worth only 4¢ per kWh, and the 6¢ plant — perhaps a fully dispatchable gas turbine located in a downtown area — could be worth 8¢ per kWh. The 5¢ bid should be rejected because the price is more than the power is worth. The 6¢ bid should be accepted because its price is well below its value; it is below the cost the utility would avoid by selecting that plant. Of course selection of a 6¢ winning bid does not mean the utility should pay 6¢ for other proposals or that it is an omni-purpose, 6¢ avoided cost.

In a fully competitive, wholesale power market, this type of analysis that compares market value to avoided cost (private value) will become an increasingly important determinant for trading behavior. The biggest winners in competitive markets will be those who best understand avoided costs.

Avoided Costs Calculations: Analyzing New Resource Acquisition

The introduction of IRP into utility decision making has charged utilities to acquire least-cost energy resources using a strategy that establishes a common framework for comparing very disparate resources. Avoided cost analysis is the common framework that establishes a mechanism for comparing resources and demand-side resources. It provides the means to compare the costs of alternative energy resources and decide which are cost effective and which are not. Yet like many features of IRP, avoided costs can be misunderstood and consequently misapplied. This chapter describes avoided cost methods and the most common errors that occur when calculating these costs.

CONCEPTS TO UNDERSTAND

Utilities must constantly balance the need to provide electricity to all customers, at every instant in time, with the need to minimize costs. While seeking least-cost options, a utility cannot compromise its ability to provide reliable service, its obligation to serve and its need to avoid unacceptable risks. Decisions confront utilities not just in terms of what resources to acquire but in terms of what resources at their disposal should be operated at any point in time.

Avoided cost analysis helps utilities assemble their least-cost plan by identifying what a resource is worth to a utility. Looking at it another way, the most a utility would be willing to pay for a resource. This is best done by looking at the specific operating characteristics and location of an actual resource under consideration and asking a number of questions. What existing or planned utility resources would the new resource displace? What time of day or year would the new resource provide energy services? Will the resource raise or lower the reserve margins? Will the resource increase or decrease transmission or distribution costs? Would overall costs be lowered or raised if the new resource were substituted for a planned resource?

To accurately assess and compare costs, all relevant expenses for existing and new resource options are included in the analysis. These include transmission and distribution savings, risk and reliability effects and often costs of environmental externalities. For instance, acquisition of demand-side alternatives can mean that costly transmission and distribution system upgrades could be postponed or avoided altogether. Similarly, renewable resources, such as photovoltaics or wind turbines, may offer the possibility of avoiding more costly line extensions into remote settings. In addition, allocating full environmental costs to resource choices generally improve the economic attractiveness of non-traditional resources.

CALCULATING AVOIDED COST

To find out what electricity is worth, avoided cost calculations ideally look at the cost of electricity (capacity and energy) over every hour of every year. Any resource not already in the resource plan can be evaluated by comparing its actual cost to the cost it would avoid were it to come on the system at no (zero) cost. This calculation is called the avoided cost. A resource that provides electricity at a cost (or price) lower than its avoided cost is, by definition, cost effective and worth acquiring.

How do utilities make this calculation? Avoided cost can be calculated in a generic or customized, resource-specific fashion. In either case, utilities begin the same way which is to undertake the IRP steps to determine the optimal, least-cost resource mis. These steps include:

- **Load Forecast**

This first step uses historical trends, econometric analyses or preferably end-use forecasts to construct a load forecast for each hour of the year.

- **Consideration of Possible Resource Options**

The utility constructs a list of options to consider. This list needs to be as comprehensive as possible by including central and dispersed supply-side resources, renewable resources, demand-side resources, power purchases etc.

- **Development of an Optimal, Least-cost Resource Plan**

Developing an optimal plan which chooses among a broad range of options is complex, but the theory can be illustrated with a simple example.

Suppose a utility is development a resource plan using two dispatchable resources.

Option	Investment	Annualized Capital Cost	Fuel Cost
1	$1000/kW	$200/kW	2¢/kWh
2	$ 500/kW	$100/kW	6¢/kWh

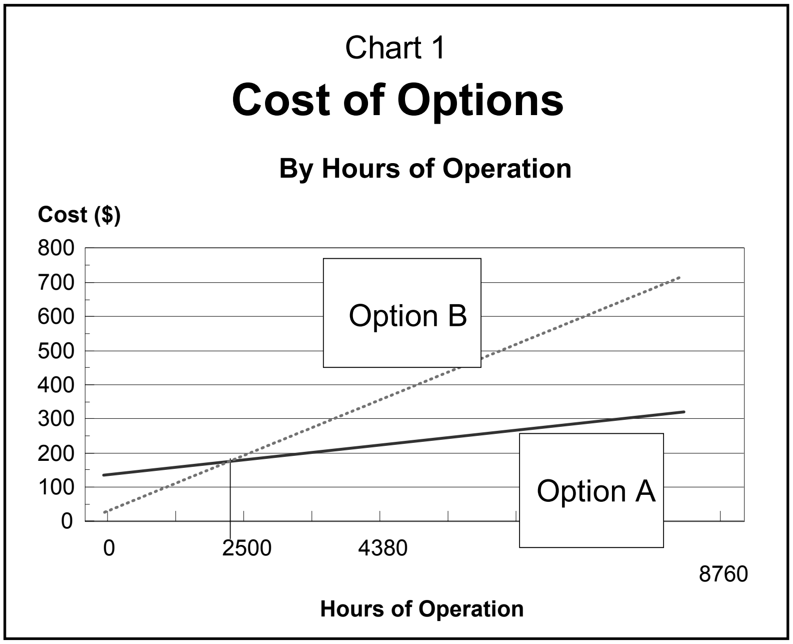
Option 1 has the characteristics of a baseload resource ─ high capital costs and low fuel costs. Option 2 is similar to a peaking unit with low capital costs but higher fuel costs. How does a utility choose how much of each of these options to buy in order to have the least-cost mix? Where is the break even point where the higher capital cost of a base-load unit is balanced by its lower fuel cost? The answer lies in looking at the 8760 hours in the year and finding the point at which it costs less to operate Option 1 with lower operating costs and at which point does it become cheaper to operate the lower capital cost Option 2.

This number is found using the graph on Chart 1 which plots costs of both options across the entire year.

Chart 1 shows that Option 1 is cheaper when in operation over 2500 hours each year. Option 2 is cheaper when in operation less than 2500 hours throughout the year.

Having derived this number, then next question is how much capacity must be operated for more than 2500 hours, and how much will run for less than 2500 hours? This is answered by taking the information found in a utility's load duration curve.[1] The illustration in Chart 2 represents a simplified load duration curve.

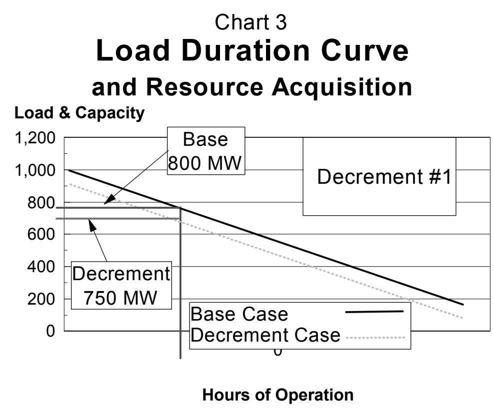
[1] A load duration curve is a utility's hourly load (or skyline which is reordered so that highest demand is hour one, the second highest demand is hour two and so on.



This shows that the highest demand required in a given year is 1000 MW, and the lowest demand is 200 MW The first graph shows that Option 1 is the cheapest resource for load in excess of 2500 hours. By drawing a line from 2500 hours until it intercepts the load duration curve, the least-cost, optimal resource mis can be determined. This graphing shows that any MW capacity which will be operated for 2500 hours or more should be Option 1 plant. Any MW of capacity which will run for less than 2500 hours should be the Option 2 plant. With this guidance, a utility is most economically served by acquiring 200 MW from Option 2 and 800 MW from Option 1. Taking into account cost for both plants, the total cost to the utility turns out to be $303.9 million.

Standardized Decrement Approach

What is a utility's avoided cost? A way to derive this cost is to suppose that the utility obtains a free, around-the-clock resource which provides 50 MW every hour of the year. This 50 MW decrement will affect the resource mix as shown in Chart 3.



Now the peak load requirement for the utility is 950 MW, and the minimum load requirement is 250 MW. Again, by drawing a line from 2500 hours to intercept the new load curve, it can be seen that, despite the free MW, 200 MW must still be acquired to meet the load requirements for 2500 hours of the year. On the other hand, now only

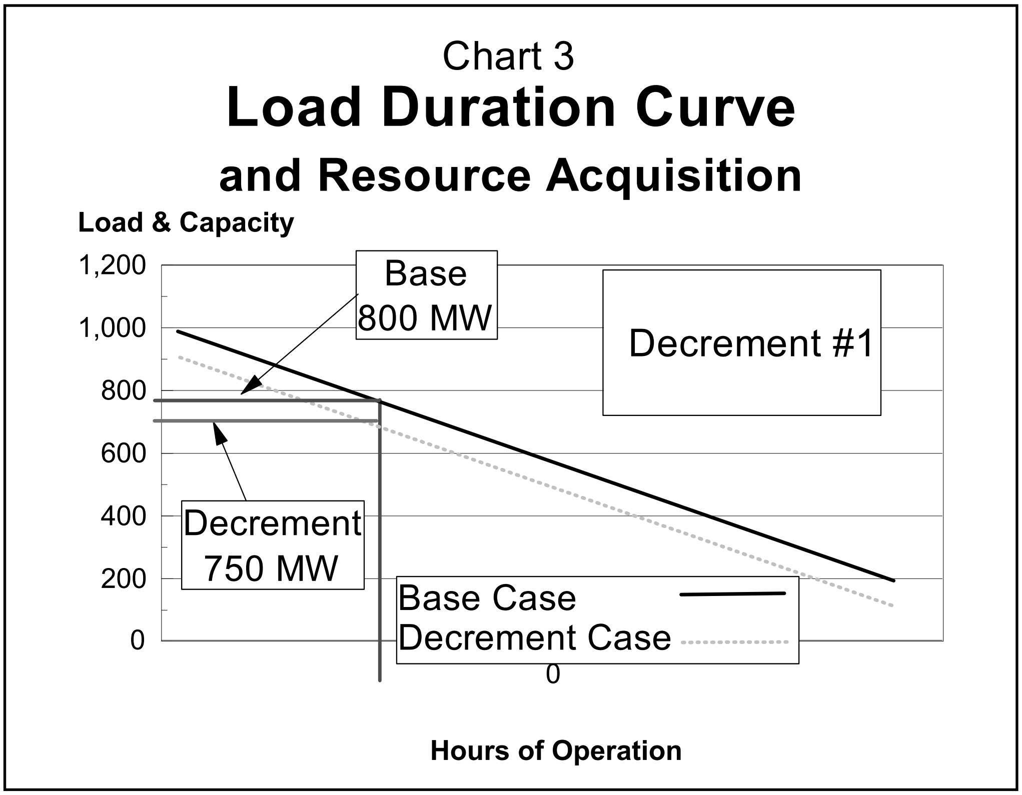
750, not 800 MW are needed to meet the base-load requirements.

The cost for purchasing 750 MW of Option 1 and 200 MW of Option 2 is $285.1 million. The cost savings from 50 free MW is the difference between the total revenue requirements of the two plans or

$303.9 - 285.1 + $18.8 million

The avoided cost is calculated by dividing the savings ($18.8 million) by the energy which no longer needs to be acquired (438 million kWh). The avoided cost is 4.3¢ per kWh. This means that the value to this utility of a 50 MW, 100 percent load factor resource is 4.3¢ per kWh.

This example is purposely constructed very simply to illustrate how to calculate a standardized avoided cost. A more "real life" situation would define a slice of the resource requirement in order to meet specific energy



needs of the utility and match the operating characteristics of the types of resources that a utility believes are available. Size, capacity factor, starting year and duration are characteristics considered by utilities when defining this standardized decrement.[2]

[2]The size of a decrement is decided by considering how sensitive avoided costs are to load levels. If avoided costs change rapidly, then accurate costs can only be assured with smaller decrements. If avoided costs are slow to change, then larger decrements are acceptable. A reasonable decrement size for an electric utility might include two years of peak demand growth or five percent, whichever is lower. In other situations, decrements are sized according to the next resource to be acquired.

When using this standardized approach to acquire resources, the decrement is then filled by resources whose characteristics match the characteristics defined in the decrement and whose costs fall below the computed avoided cost. Resources, at or below avoided cost, are added in ascending order beginning with the least expensive. This could mean that even though a resource falls below avoided cost, it will not be acquired if there are enough options to fill the decrement that cost even less.

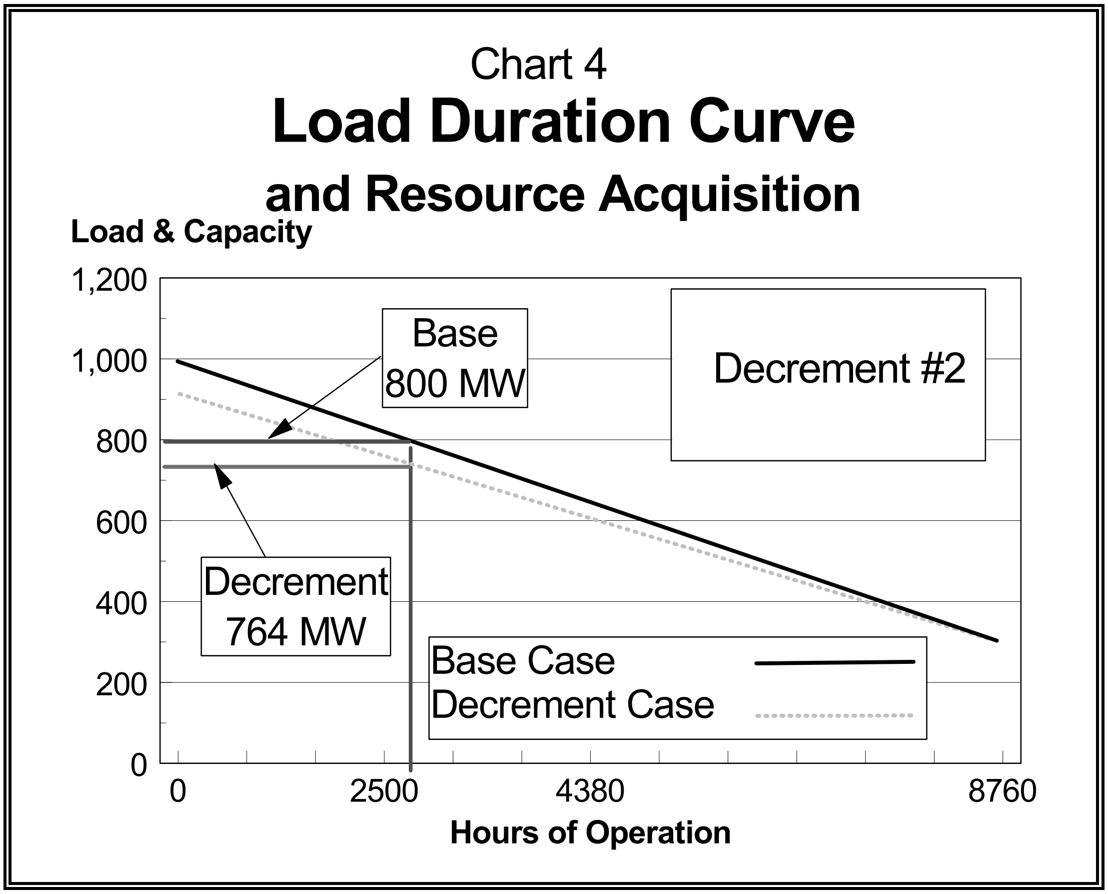
In addition to using the standardized approach as the tool to actually acquire resources, it can also be used to inform the market place of an approximate price a utility is willing to pay for a resource. In turn, the utility can quickly test the market place and assess what resources are available. This survey is followed by a resource-specific, customized avoided cost.

Customized Avoided Cost Calculations

The example above can be built upon to illustrate how to derive a customized avoided cost. In this case, shown in Chart 4, suppose a DSM measure that would reduce peak demand by 50 MW and have no impact on the lowest demand. Further suppose that intermediate demand levels are reduced by less than 50 MW.

The free resource affects both the baseload and the peaking requirements. Now, 764 MW are needed for 2500 hours or more and 186 MW are needed for less than 2500 hours. The total cost of this resource mix is $290.2 million. The cost savings from this resource is:

$303.9 - 290.2 = $13.7 million



While the total dollar savings is smaller in this example, because the actual amount of energy saved is also smaller (219 million kWh), the avoided cost now, at 6.3¢ per kWh., is about 50 percent higher than the 4.3¢ for around-the-clock displacement resource. The value to the utility for this partial resource is 6.3¢ per kWh. This occurs because the alternative resource provides its capacity and energy in the time periods that costs are highest. This 50 percent avoided cost differential between baseload and peaking units is not uncommon.

This illustrates that the best way to come up with accurate avoided costs is to consider the specific operating characteristics of a replacement resource including MW, capacity factor and time period of operation.

The technique requires a specific answer to the question of how the resource plan would change were a specific, new resource added to the mix? By re-optimizing the resource plan to accommodate the addition of a specific resource, and exact, customized avoided cost of an individual resource can be calculated.

The avoided cost is what the utility should be willing to pay to purchase an energy resource. Any cost, at or below what a utility already expected to pay, is a cost-effective decision on the part of utility. This technique determines what it is worth to the utility to acquire this resource. Whoever is offering the resource must then decide whether the calculated avoided cost is an acceptable price for the option.

Avoided Cost Shortcuts To Consider

Because customized avoided cost calculations can be time consuming, shortcuts have been developed which allow utilities to calculate the avoided cost for a specific resource without re-optimizing the resource mix each time.

Peaker Method

A simple shortcut that has been derived calculates avoided cost based on the cost of a peaking unit. Here, the two units from the example above are used to compare the results from this technique to those derived from a customized avoided cost calculation. In this case, to determine the avoided costs, the capacity costs solely from the peaking unit are used in the calculation. Avoided costs are taken to be the operating costs of the most expensive unit which is actually in operation during each hour. In this example, capacity costs are assigned to the ten percent of the hours when the load is highest.

The cost is determined by assigning costs to different time periods of operation in the following manner:

	10% operation or 876 hours	876-2500 hours	over 2500 hours
Marginal Energy Costs	6¢	6¢	2¢
Capacity Costs	11.4¢[3]	0¢	0¢
Avoided Cost	**17.4¢**	**6¢**	**2¢**

After a decrement has been established, the number of kWh that each decrement has in each of the three time periods is tallied up to derive an avoided cost. Applying this calculation to the second decrement example where there is a 50 MW reduction in the peak period and no load reduction at the lowest load, the avoided cost is 6.1¢, not 6.3¢. The difference is attributable to the fact that capacity costs, in fact, vary by time. If you reduce loads year round, you build less baseload, but if you reduce loads mainly on peak, you build fewer peaking units. Customized accounting can take this into account, while the peaker method cannot.

This cost, though, is fairly close to the answer derived from the more accurate customized approach. And the cost will be closer the more the replacement resource resembles a peaking unit.[4] But is close good enough? Can a utility live with it? Here the tradeoff arises between how critical it is to have the avoided cost calculation be precise. If there is a lot of money at stake, it may be in a utility's best interest to re-optimize its resource plan rather than rely upon the Peaker method. Also the utility may be interested in getting other information from the re-optimization exercise that it cannot otherwise obtain, such as the impact of a specific resource on reliability, unit size requirements and unit forced outages.

Shortcuts With Limited Application

Allocating Costs to Time of Day

It is tempting to undertake a shortcut in which a single avoided cost calculation for a utility's resource mix is computed for every

[3] The cost of the sample peaker is $100 per KW per year. This is spread over the ten percent of the year, 876 hours, when load is highest. Thus $100/876 hours = 11.4¢ per kWh

[4] Where a utility is building primarily baseload resources, using a peaker shortcut may introduce fairly large errors.

hour of the year. A resource-specific avoided cost could then be determined by figuring out the resource's hour-by-hour operating characteristics and tallying up the respective avoided costs. This is attempted in some states. But in actuality, it is difficult, if not impossible to do. Many schemes have been proposed to assign costs to different hours. However, because no scheme goes back to the fundamental structure of how electricity is used, the allocations of cost are fundamentally arbitrary. This suggest that, when using this analysis, special care must be taken when evaluating resources which are disproportionately on peak.

The Next Plant Approach

A very common, but mistaken shortcut, uses the next planned unit as the avoided cost for acquiring any new supply or demand resource. Here a utility might say "we are planning on building a gas turbine, and therefore, any resource option that is cheaper than that falls below avoided cost." In doing this, they are able to calculate a single number, say 6 ¢ per kWh as the cost of a gas turbine and say that they should acquire any resource that is cheaper than this price and reject any resource that is more expensive. This only works in situations where then new resource resembles a gas-fired turbine.

However, if the proposed resource is very different in the way it provides an energy service, the 6¢ per kWh will end up having very little validity. Take, for example, a weatherization program which saves energy during peak winter months. Earlier calculations and intuitive knowledge confirm that peak power replacement has a higher avoided cost than baseload power replacements. In addition, a demand-side program is provided directly on-site which eliminates transmission and distribution costs. Given these factors, a weatherization program can end up being worth more than 6¢ per kWh to the utility. Yet by using the next-plant approach, this alternative might be immediately, and mistakenly, rejected.

WHAT KEEPS GOOD AVOIDED COST CALCULATIONS FROM OCCURRING?

As part of the IRP process, the purpose of avoided cost calculations are to ensure that a utility locate and acquire the lowest cost mix of energy resources. The following constraints hamper the IRP process in many states and can mean that customers are not receiving the most economical mix of resources.

C Demand-side management is not treated as an equal player. When this occurs the environmental and potential financial benefits are sacrificed.

C Some utilities have been reluctant to turn to the market place to obtain either supply- or demand-side resources.

C Potential savings in transmission and distribution investments are frequently overlooked. Renewables and demand-side resources have a better change of emerging as cost-effective options when the costs associated with transmission and distribution are included in the calculation of avoided cost.

C Surplus capacity does not mean that the avoided cost is zero. There are always avoided fuel costs and often avoided transmission and distribution costs.

- While dispatchability is a good characteristic, it is not a necessary characteristic for every resource choice. There are non-dispatchable resources that, if acquired, would lower a utility's cost without diminishing its ability to provide electricity. Utilities need to determine just what dispatchability is worth and how dispatchability should influence cost.

- Many resources, particularly DSM and dispersed generation, will result in lower losses on the transmission and distribution system. Any marginal reduction in losses should be taken into account.

- Some resources, particularly smaller resources, may increase reliability and therefore allow the utility to carry lower reserves. The associated savings should be captured in the analysis.

- Occasionally the argument is advanced that intermittent resources like wind and solar should have no capacity value because they may not be available at peak times. This is wrong. Instead, the capacity value of intermittent resources should be determined by looking at how they reduce the capacity needed to maintain reliable service.

Until now, this discussion has focused on the more technical aspects of avoided costs and in doing this takes as a given a variety of assumptions about the future. These assumptions include fuel price forecasts, load growth and the remaining life of a nuclear plant. In reality, these uncertainties can have a major impact on the analysis (in some cases a far greater impact than the impact of the issues presented in this paper). This suggests that forecasts used in the avoided cost analysis require careful scrutiny because the risk from forecasting errors can be great.[5]

CONCLUSION

Understanding and correctly calculating avoided cost will go a long way toward making sure that utilities locate and acquire the least-cost energy resources. However, when avoided costs are poorly done, the cost of electricity will rise. Poor avoided cost calculations result in acquisitions of resources that are too expensive while, at the same time, overlook cost-effective resources.

Customized avoided cost calculations are the most reliable way to compute what a resource is worth. Standardized avoided costs are particularly useful to let providers of energy services know roughly what a utility is willing to pay to acquire a new resource and to let the utility test the market and see what resources may be available. Shortcuts should be used selectively, with a full knowledge of their built-in biases or limitations.

[5] Risk and uncertainty are discussed more fully in a later chapter.

Energy Efficiency in a Competitive World

In the decade between 1985 and 1995, utilities became the dominant player in finding and funding the efficient end use of electricity. In 1993, 991 utilities operated DSM programs, spending $2.8 billion — a 13 percent increase over 1992 expenditures. DSM investments saved 44,000 Gwh of energy and reduced potential peak demand by 40,000 MW in 1993.[1]

This paper reexamines the economic and social reasons that motivated this large, utility-related DSM industry, reasons which remain relevant today. Looking at energy efficiency through the filter of increased competition reveals new opportunities, new threats and confirms a continued role for regulatory policies to maintain the benefits offered by DSM.[2]

[1] S. Hadley and E. Hirst. 1995. Utility DSM Programs from 1989 Through 1998: Continuation of Cross Roads? Oak Ridge National Laboratory, ORNL/CON-405, February. The energy and demand savings include the 1993 effects of DSM investments made in 1993 and earlier years.

[2] DSM is a broad term that encompasses load building and load growth as well as load reduction or energy conservation, also called energy efficiency. Load building, by spreading fixed costs over more kWhs sold, can lower the unit price of electricity even though it may not reduce the total cost of providing electricity. Load management programs shift kWh use from on-peak to off-peak without reducing sales. Pricing strategies such as Time-of -Use rates or Real Time Pricing do the same thing by giving customers price signals that more accurately reflect costs. Of national utility expenditures on DSM in 1993 (not including load building, which was not reported), 70 percent was for load reduction. Of the various DSM strategies, it is load reduction (energy efficiency) that is most at risk in a competitive world.

WHY ENERGY EFFICIENCY MAKES SENSE

Lowers long-run costs. To improve economic efficiency, regulators have encouraged utilities to pursue DSM in situations where it reduces demand at a cost less than generating new supply. Estimates of the technical potential for savings range from 24 to 44 percent (EPRI) to 70 percent (Lovins). How much of this technical potential is cost effective depends on the cost of DSM in comparison to the cost of generating additional electricity, which would be avoided. The higher the avoided costs, the more DSM is cost effective.

In recent years, avoided costs have declined due largely to lower fuel prices and excess capacity. As a result, fewer DSM measures are cost effective. Lower avoided costs, however, do not justify abandoning DSM. The period of time in which avoided costs were high was long enough to enable DSM programs to move well along on the experience curve. As a result, today utilities (and others) are able to deliver efficiency services more cheaply. Many new DSM technologies have also declined in cost as markets, spurred by the activity of utility programs, have matured. Thus even with long-run avoided costs at 3 to 5¢ per kWh, there remains much DSM that can be achieved.

Improves environmental quality. Fossil-fueled power plants are major emitters of air pollutants. DSM, by reducing the need to generate as much electricity and burn as much fuel, reduces environmental impacts.

Some air pollutants are now regulated by the Clean Air Act and the Clean Air Act Amendments of 1990 (CAAA). The CAAA places a cap and trading mechanisms on the emission of sulfur oxides, a contributor to acid deposition and calls for reductions (but no cap or trading) in emissions of nitrogen oxides, a contributor to acid deposition, ground level ozone and nitrogen saturation. Other emissions that may be regulated in the future include small particulates, air toxics such as mercury and greenhouse gases such as carbon dioxide.

Except for sulfur oxides, the environmental costs of emissions are neither measured nor included in the price of electricity. As long as they are not internalized, DSM investment will be below desired levels.

Customers like it. Investments in DSM have turned out to be a valuable customer service. Utilities, many of which received bad publicity during the period of nuclear power plant construction and cost overruns, were able to provide a friendly, direct and useful service to their customers. Customers liked the services they received (weatherized homes, energy audits, and energy efficient lighting) and liked the utility for providing these services.

Benefits the economy. DSM has had its role in economic development as well. Studies examining the direct, indirect and induced impacts of energy efficiency spending find investments produce more jobs and increase incomes when compared to electricity generation. A national study looking at a high energy efficiency scenario, estimated an increase of over one million net jobs by the year 2010 and a rise in personal incomes by 0.5 percent.[3] A Minnesota study estimated the creation of over 3,800 net jobs by 2005 from investments in energy efficiency, [4] and a Maine study calculated DSM investments contributed $26.6 million to the Gross State Product in 1992.[5]

WHY ENERGY EFFICIENCY IS AT RISK IN RESTRUCTURING

Benefits from DSM accrue under cost-of-service regulation as well as in a more competitive environment. There are, however, important aspects of a competitive world that place DSM at risk.

---

[3] H. Geller, J. DeCicco and S. Laitner. 1992. Energy Efficiency and Job Creation: The Employment and Income Benefits from Investing in Energy Conserving Technologies, American Council for an Energy Efficient Economy, October.

[4] Economic Research Associates. 1993. Energy Efficiency and Minnesota Jobs: The Employment Impacts of Electric Utility Demand-Side Management Programs, prepared for the Midwest Office of the Izaak Walton League of America, February.

[5] S. Laitner. 1994. Energy Choices Revisited: An Examination of the Costs and Benefits of Maine's Energy Policy. Prepared for Mainewatch Institute.

Consumer Investments

Energy efficiency is not restricted to utilities. Consumers, too, have the option of making cost-effective investments as well, but for a number of the following reasons, many have chosen not to.

- Information about how to save energy can be difficult to come by, and when it is available, there are often confusing and contradictory claims.
- Consumers have limited access to the capital necessary to make long-term investments.
- The payback period consumers want is much shorter than the payback period of utility investments in new energy resources.
- The incentive to conserve energy is often split between building owners, who are responsible for long-term capital investments and building occupants, who rent and pay the energy bills.

Stranded cost. In anticipation of competition, the price of electricity has become much more important to utilities. Utilities anticipate a price-based world where customers will compare their rates to the rates of an alternative supplier. Because existing costs are high relative to the cost of new power sources, utilities with strandable costs are afraid they will not be able to recover them in a competitive market. They see energy efficiency investments as adding to their strandable costs problems. Energy efficiency will raise rates at the same time market competition will keep utilities from charging a high enough price to recover costs. Utilities also worry that customers who participate in an efficiency program will have the option of choosing another supplier before the investment is fully recovered.

Lost revenues. Utilities implementing energy efficiency programs incur two types of cost. The first is the cost of program administration which includes any payments the utility makes to participating customers for energy efficiency measures. The second is the loss of revenue from the kWhs not sold. Because the utility also avoids certain costs (largely fuel and purchased power) by not supplying saved kWhs, it is the net lost revenues that really matter. One way utilities cover lost revenues is by raising rates for all customers, even those who did not participate in energy efficiency programs.

For most utilities today, rates are higher than avoided costs. This means energy efficiency programs that have no direct costs to the utility still result in net lost revenues. Thus even customers who undertake to save energy on their own will negatively affect utility rates. In other words, it is impossible for utilities (or even customers) to pursue energy efficiency without exerting an upward pressure on rates.

How lost revenues are treated differs substantially in a competitive and in a regulated world. In a traditionally regulated environment, utility shareholders absorb any net lost revenues in the period between rate cases. But, at the time of the next rate case, sales are re-forecasted, costs are re-estimated, and prices are increased to take account of net lost revenues. In a competitive world, on the other hand, where prices are set by the market, there is no opportunity to increase prices, so revenue losses persist. The permanent loss of revenues is energy efficiency's contribution to stranded cost.

Conflict of financial interest for integrated utilities. Utilities that operate a distribution system and own generation face an inherent conflict if they seriously pursue energy efficiency. Currently, the utility as a whole is regulated as a monopoly, and the costs of both distribution and generation are bundled in rates. In the future, assuming generation is free to earn unregulated profits, successful energy efficiency, by lowering demand for kWhs, will lower the price that may be received for energy. Lower sales and prices will in turn lower the asset value of their generators. Integrated utilities want just the opposite: higher sales, higher prices and higher asset values.

If the generation activity remains part of the utility (as a separate accounting function or even as an affiliate under a parent company), company management will see energy efficiency reducing generation revenues — the place with most potential for profit. But because generation is unregulated, the company cannot claim the safety net of regulatory cost recovery.

Price pattern and market risk. Assume a utility is faced with a choice between two resources. One is a combined cycle gas turbine with a levelized cost of 3¢ per kWh. The other is an energy efficiency program with a levelized cost (total resource cost) of 2.9¢ per kWh. To simplify the case, assume further that both resources avoid the same costs. How might a utility evaluate these choices?

Price pattern. Even though the levelized cost of the energy efficiency is slightly lower, the timing of the costs favors the gas turbine. Gas turbines have relatively low capital costs, projected gas costs are low, and the fuel expense is incurred at the time gas is purchased and consumed. Nearly all the costs of energy efficiency, on the other hand, are loaded on the front end. As a result, costs go up in the near term even though they will be lower over the long term. In retail competition, near-term costs matter a lot.

Market risk. A utility buying energy efficiency when its competitors buy the gas turbine faces significant a market risk. If the price of natural gas drops, the utility choosing energy efficiency will be locked into a fixed price at the same time its competitors experience lower costs and charge lower prices. To avoid this risk, the utility will choose the gas turbine. Even if fuel prices rise, the utility will be in the same boat as other utilities who made the same purchase; it will remain competitive and not look foolish because its decisions would be in keeping with other utilities.

Encourages marginal cost pricing. For the most part, increased competition will tend to encourage rate designs in which marginal consumption is priced at marginal costs. In the past when marginal costs were higher than rates, states abandoned declining block rates and replaced them with flat or inverted block rates as a way to send a correct price signal to consumers. Given that many utilities today face high embedded costs and low marginal costs, the situation is the reverse. Translated into rate design, this means declining block rates are being adopted with greater frequency. Two observations can be made about this.

On the positive side, if marginal prices reflect marginal costs, net lost revenue from energy efficiency programs will be less of a problem, and utility opposition to energy efficiency will be reduced. But even in the unlikely event of marginal prices exactly matching marginal costs, the utility still has to cover the direct cost of the programs. This will raise rates. To avoid this, utilities may attempt to shift all direct costs to the program participants. They may offer financing instead of rebates and/or charge for technical assistance. Some customers will be willing to pay the full cost, but in general the level of participation and savings that characterize the most successful programs will not be achieved.

On the negative side, lower tail block rates will dampen consumer interest in energy efficiency. With lower marginal prices, paybacks will be longer, and it will be harder to justify energy efficiency investments. This will also make it more difficult for energy service companies to convince their commercial and industrial clients to make comprehensive efficiency investments. Energy savings that are cost-effective in the long run will be rejected.[6]

Some assert that utilities and other sellers of power in a deregulated market will offer a rich variety of energy services in an effort to differentiate themselves from their competition. Undoubtedly many valued services will come from this diverse set of offerings, but it is unlikely services will be offered that cause lost revenues, lower the demand and price of power, create market risk and increase the possibility of stranded investments. Energy efficiency will do all of these. Utilities may be able to get customers to pay for the direct costs of energy

Electro-technologies -- Energy Efficiency and Load Building

Many utilities are involved, to one degree or another, in attempts to persuade customers to switch from a process powered by a competing fuel to one that uses electricity more efficiently. By encouraging sales (and/or development) of these technologies — efficient heat pumps, lawn mowers powered by rechargeable batteries and electric cars — utilities promote load building. Where do these efforts belong in discussions of energy efficiency?

The primary question for deciding whether load building from an electro-technology is cost effective is the same as the threshold question for energy conservation. Does the product (or program) result in consumers meeting their needs at the lowest overall cost? The Total Societal Cost (if environmental costs are considered) or Total Resource Cost (Cost Effectiveness testing is discussed in more detail in *Integrated Resource Planning for State Utility Regulators*, p. 83) tests for evaluating conservation programs can be used to evaluate electro-technology programs. These tests can distinguish between cost-effective and non cost-effective electrotechnologies. Use of the Rate Impact Measure (RIM) test, however, for sales promotion programs will not be meaningful. If retail rates are above marginal costs, all promotions resulting in increased sales will pass the test.

[6] Customers could be interested in more than energy savings benefits. There are other benefits such as increased comfort, productivity, or quality control that are also appealing In fact, some utilities have been learning to market energy efficiency improvements under these headings.

efficiency services, but it is highly unlikely customers will want to pay for secondary costs as well.

WHAT CAN REGULATORS DO?

Regulators have a variety of tools to increase the viability of energy efficiency in a more competitive environment. The tools described below as well as in more details in other chapters do not guarantee energy efficiency will thrive, but they can create a climate for success.

- **Wholesale competition.** A competitive wholesale model can achieve most of the benefits of competition. Under many wholesale models, retail utilities and regulators will share responsibility for making resource choices for consumers. (See *Wholesale Competition* chapter). IRP remains the best tool to make these choices. Regulators can focus planning decisions to minimize long-term costs, consider both supply-side and demand-side resources and look to competitive bidding to determine the lowest-cost resources. This will help keep energy efficiency in the resource portfolio. This option may also work to a lesser degree in a scenario of limited retail access where some customers choose alternative suppliers, but many customers remain as "core" customers of the distribution utility.

- **IRP for distribution planning.** Distribution utilities will continue upgrading, reinforcing and expanding distribution facilities as loads grow. Distributed, small-scale generation and localized load management and energy efficiency should be considered as a cost-effective alternative to grid expansion. While load management may fare better, energy efficiency can help trim peaks. Also, distribution lines, with steadily growing load curves, will benefit from energy efficiency, and energy efficiency can help avoid siting problems caused by neighborhood objections. A few utilities are beginning to think in these terms.

- **Bill caps**. Performance based regulation (PBR) in the form of bill caps (not rate caps) can rely on energy efficiency to reduce the average customer bill. This type of PBR allows a utility to make a profit when the cost of serving all customers is lowered. A number of utilities, including Portland General Electric, Florida Power and Light and Consolidated Edison are operating with PBR bill caps.

- **PBR with an efficiency target**. This type of performance standard most resembles current incentive regulation and is a direct way to encourage energy efficiency. Utilities are rewarded if reductions are made in energy use and penalized for failing to meet targets. Recent experience, however, has shown some utilities prefer to forego incentives to avoid some of the liabilities of energy efficiency.

- **Environmental compliance.** Generators, anticipating environmental regulations on emissions such as mercury, CO_2, VOCs and particulates, will depend more frequently on energy efficiency to insure future compliance.

- **Divestiture of generation.** Some commissions have considered whether to urge utilities to sever the relationship between the generation and the distribution arm of the company through divestiture. By removing the incentive to sell all output of company-owned generation at the highest possible price, cost-effective energy efficiency investments would become more attractive to the distribution utility.

- **System benefits charge**. One of the most direct ways to fund energy efficiency in a more competitive environment is through the use a non-bypassable, competitively neutral system benefits charge for the use of distribution wires. (See chapter on *System Benefits Charge.)*

Energy Efficiency Program Strategies

In many jurisdictions, utilities have been the key stimulants, if not deliverers, of energy efficiency services. With uncertainty surrounding competition, utilities are concerned about anything that will increase rates, including energy efficiency. To reduce rate pressures, many utilities have proposed cutting all DSM programs, some have explicitly proposed offering only programs that pass the Rate Impact Measure (RIM) test,[1] and others have revised programs to reduce or eliminate direct costs to the utility. Low cost to the utility means program participants rather than ratepayers pay most or all of the cost of the programs.[2]

If regulators want utilities to continue offering energy efficiency programs, there are a variety of policy options available to them. (See *Energy Efficiency in a Competitive World* chapter.) This chapter examines different program strategies for utilities to pursue low or no-cost programs. None eliminate direct costs to utilities, but each has the potential to reduce costs and thereby mitigate rate impacts. Rate impacts are not something that just happens. They can be deliberately controlled within an acceptable range, by selecting low-cost strategies and programs such as those described below.

Reduced Rebates And Incentives

In the past decade, many utilities have offered customers a financial incentive in the form of grants or rebates to install energy efficiency measures. These programs, as documented by the American Council for an Energy Efficient Economy, have been critical to achieving high penetration rates, ranging from 60 to 100 percent. At the same time, the increasing competitiveness of the industry has caused many utilities to re-evaluate their efficiency programs. For this reason, utilities are trying to get the same savings for less money by taking advantage of the groundwork they laid over the past ten years. Thanks to rebate and incentive programs many customers are familiar with energy efficient products, and market infrastructures have been created for them.

With these two major achievements under their belt, one way for utilities to lower costs is to reduce the incentives and rebates. Doing this sacrifices some level of customer participation (and therefore reduces energy savings), but many customers will still respond to a lower incentive or rebate.

Another strategy relies on energy efficiency as a tool to attract new customers or retain existing customers. A successful approach here produces a number of advantages. Cost-effective, energy efficiency investments are made. Customers see lower electric bills. And, to the extent that the program either acquires or keeps a customer who would otherwise leave, there is no lost

---

[1] The RIM test is a method for calculating energy savings benefits and costs. A program that passes the RIM test will have no rate impact, on average, over the life of the energy savings. However, it will be difficult, if not impossible, for most load reduction programs to pass the RIM test, even if the program has no direct cost to the utility, because of the forgone revenue loss associated with the energy sales foregone.

[2] In the past, many utilities had been willing to pay part of the cost of energy efficiency, even if it raised rates, as long as it reduced costs to all ratepayers in the long run.

revenue. In fact, it is quite possible this strategy could result in lower electricity rates, as well as lower bills for all customers.

An example of this program is one offered by Northeast Utilities (NU). This PRIME (Process Re-engineering Increased Manufacturing Efficiency) program is very targeted and focuses on large industrial customers who the utility believes are most likely to leave. Taking the view that energy efficiency can best be achieved by making changes to the manufacturing process, NU brings in industry experts to conduct a comprehensive audit that examines inventory control, environmental compliance, labor productivity, waste stream management and energy, water and wastewater control. Following the audits, investments in process improvements are made using a combination of customer and utility funds, with the utility steering the customer to the utility's more traditional rebate or financing programs.

Participant Pays

The ultimate goal in lowering rebates and incentives is to develop programs in which the participant pays program costs. Because the financial incentive to participate is not as great, these programs require significant support services, such as energy audits and technical analysis, preparation of bid documents or performance specifications, bid review, inspections or building commissioning. The participant may be asked to pay for the full cost of the measures installed, for the measures' costs plus some support services or for the total program cost, including administrative costs. The more the participant pays, the lower the rate impact and thus the more acceptable the program is to non-participants. To make sure though that the program is also acceptable to participants, marketing efforts must emphasize the level and quality of service to be provided.

The participant pays approach may be implemented as a financing program in which the utility first loans money to the participant, then recovers the loan plus interest through a line item –an Energy Service Charge (ESC) – on the participating customers's monthly bill. To make the financing attractive, the loan is structured to provide the participant with a positive cash flow. This may include a lower-than-market interest rate, a longer-than-normal payment term or selection of measures with shorter payback periods. There are two well-known examples to this approach.

PacifiCorp offers their customers a series of programs termed Energy FinAnswer, targeted at a variety of markets: new commercial construction and industrial and large and small commercial retrofits. In these programs, participants pay the installed equipment cost via the ESC but not the associated marketing and administration costs, which can account for upwards of 50 percent of the total cost. Limiting participant contribution to equipment costs recognizes that if a program is trying to get customers to bite and achieve good market penetration, not all the costs can be placed on participants. Customers deciding whether or not to take part continue to need hand holding, support, guarantees, etc. A small price impact can be expected when program costs are allocated to all ratepayers. However, Pacificorp continues to experiment with varying levels of program subsidy, including charging for some services, such as building commissioning.

To date, the most successful of Pacificorp's programs (50 percent market penetration) is the one targeting new, large construction in the commercial sector. Penetration in small commercial and industrial sectors is not yet as good. One reason for the lower success rate is that these programs have not been around as long. On the other hand, it may turn out these markets have different needs than are being met by utility loans and the ESC.

Southern California Edison (SCE) began a similar program in late 1993. ENvest focuses on large institutions — federal installations, municipal projects and school districts. Programs with public institutions have been able to take advantage of lower cost municipal financing to make projects more viable. While similar to the Pacificorp's Energy FinAnswer, there are also some significant differences between the two programs. First, in addition to equipment costs, program costs are also recovered. Second, SCE is trying to make a profit. And finally, the lion's share of the money invested comes from shareholders, not ratepayers. Of the $90 million raised, $75 million comes from shareholders, and the balance is generated from ratepayers.

A participant pays program with a different twist and with little history thus far is end-use pricing. Here, a utility provides an end-use service for a flat fee. To understand how it works, one can compare the difference between how a customer would buy a refrigerator with and without this mechanism. Without end-use pricing, customers buy as they do today. They purchase a refrigerator from a supplier, kWhs from the utility company and repair services from a maintenance person. With end-use pricing, instead of making separate purchases, customers buy a refrigeration service. They pay a monthly fee, and in return the utility provides a refrigerator, maintenance and power. To turn a profit, the utility will try to keep their expenses as low as possible. The best way to do this is to install an efficient refrigerator and maintain it well.

A small pilot end-use pricing program is currently being conducted by Wisconsin Electric Power Company. Although the scope of and experience with this effort is small, interest in it is growing. If successful, a major attraction of end-use pricing will be that costs are only borne by those who participate.

Market Transformation

Conventional energy efficiency programs such as rebates and incentives try to influence consumer decisions. One way the success of these programs can be measured is by observing how customer decisions have transformed the marketplace. For instance, utility rebate programs made electronic ballasts such a common technology that now it is almost a standard operating procedure to specify their use along with more efficient fluorescent lamps in commercial offices.

While utility-spurred consumer decisions can drive and change the market, true market transformation efforts rely less on individual consumer decisions and more on the decisions made by a smaller and more influential group of manufacturers, wholesalers and vendors. Influencing decisions farther up the delivery channel means less money needs to be spent on rebate and incentive programs. Gaining access to these decision makers, though, is not always easy. Identifying and making production changes will be neither fast nor cheap.

To be successful, there must be coordination and long-term commitment among all the players — different utilities, vendors, manufacturers — and an understanding that higher costs in the early years will be rewarded not by immediate savings but by savings in later years.

A number of very different examples exist supporting market transformation efforts.

Golden carrot refrigerators. A competition sponsored by 23 utilities offered $30 million to the manufacturer able to produce the most efficient, environmentally-safe refrigerator. Today, in addition to Whirlpool's winning entry, refrigerators developed by other competitors are in the marketplace.

Uniform efficiency specifications. The Consortium for Energy Efficiency is working with utilities across the country to develop uniform specifications for products such as compact fluorescent lights and HVAC equipment. Once this is done, manufacturers will work with a single standard. By combining forces and creating enough of a market, utilities associated with the consortium hope to increase production of the most efficient equipment models.

Manufactured housing standards. A number of utilities in the Pacific Northwest have worked with 12 to 15 builders of manufactured homes to develop efficiency standards exceeding those already set by the U. S. Department of Housing and Urban Development. In return for building to the higher standards, these utilities pay the manufacturers on average $2000 per home. The program, which has been running for six years, appears to have been so successful that some utilities no longer feel it necessary to offer the incentive payment. They believe consumers have learned to expect a higher standard, and therefore manufacturers will continue to build and sell more energy efficient homes. Also, the added expense associated with a number of standards was linked to the learning curve and not an increased cost of materials. Today's builders now know how to build the higher-standard home more inexpensively.

Improved computer efficiency. Energy Star Computers is an initiative in which the U.S. Environmental Protection Agency worked with manufacturers to build computers and related equipment with reduced power requirements when on but not in use. Of all examples of market transformation, this one, because it required no new technology and no new costs, was very easy and cheap to implement, and, as a result, has been quite successful. Many public agencies are now specifying Energy Star computers, and many consumers are purchasing them without even being aware that they are doing so.

Market transformation programs raise some unique issues. The first is how to measure the impact. When a customer acquires an energy efficient resource, the measurement marker is how many kWh were saved. Because each program participant is known, this is relatively easy to track. Since the focus of market transformation is to expand the number of energy efficient products available in the market place, individual customers are not so easily identified and tracked. This makes program evaluation much more challenging.

Second, in a competitive world, some utilities question whether they should be putting money into a consortium to help transform the market in which they do not obtain a commercial advantage. These utilities worry that a neighboring utility will become a free rider by receiving cost-free benefits. They also wonder how regulators will treat the expenditures they make for market transformation, especially when the money is invested as part of a larger consortium where the outcomes are not easy to predict or quantify.[3]

These issues are not insurmountable, but they need careful discussion at the commission level to be sure that everyone has the same expectations.

Technical Information And Support

In the early 1980s, audits were commonly conducted to identify energy saving opportunities. Program evaluations, when they were conducted (which was rare), showed audits achieving energy savings of about five percent but missing a great deal of cost-effective measures. Two reasons were cited by customers for not investing in these savings: access to capital and poor payback. The utility response to these concerns — making capital available to improve the payback — ushered in the rebate era.

[3] It is worth noting here that non-utilities, including government, have taken the lead role in some market transformations, such as with Energy Star computers.

Today's utilities, because they have more experience helping customers make commitments and helping them choose which technologies should be installed, believe they now have much more to offer customers in the way of technical support and information than they did ten years ago. These utilities are returning to audits and other related programs both because they believe they will now work better and because program costs are low.

In many cases, this type of support is offered more as a customer service than as a resource. A problem with this position is that when treated as a service, very little evaluation is conducted to determine the extent of the savings. This is unfortunate on two counts. First, the energy saved should be viewed as a resource, and second not knowing how much energy has been saved undercuts the whole value of acquiring energy efficiency resources.

There are some good examples of technical support programs.

Resource conservation manager. This program was initiated by the Superintendent of Public Instruction in Portland, Oregon who was looking for ways to respond to the declining annual budgets for school operations. One solution, developed in conjunction with Portland General Electric and Northwest National Gas, supports a salaried position charged with increasing efficiency and promoting conservation in energy, water and solid waste. The salary is guaranteed by the utility, but in initiating the program, both the school district and utility felt savings identified and implemented by the resource manager would cover the salary. This is exactly what has happened.

After the first year of operation, each of the six participating school districts saved more than the cost of the salary through improvements in operation and maintenance. Estimates from year two again project more savings than costs. What is less clear at this time is whether the net savings will be great enough to also fund capital improvements.

Because many investments in capital improvements have not yet been made, this effort shows that audits are a low-cost way to identify and acquire some cost-effective resources. However, technical support alone cannot be relied upon to capture all that is cost effective.

Subscription service program. A more high profile example of technical assistance is Niagara Mohawk Power Corporation's (NMPC) subscription service program which was inspired by some industrial customers. These customers felt all the cost-effective modifications to their plants had already been made. They believed they would be unable to take advantage of any utility-sponsored program, and as a result, did not want to not pay for energy efficiency. To accommodate this concern, NMPC's largest customers were given a choice. Under option A, customers continued to pay the conservation charge and take advantage of utility-sponsored programs. Under option B, customers could opt out of paying a portion (40 percent or 1.5 mills/kWh) of the charge as long as they conducted a comprehensive audit at their own expense.

In allowing NMPC to pursue this path, the New York Commission increased the already-set performance target for industrial energy savings. This was done to make sure that NMPC would work even harder to get customers who chose option B to actually make investments in the opportunities identified by their audit.

Option B was selected by 38 percent of the eligible customers (who used 54 percent of the electricity). From 135 customer audits, roughly 1000 ECMs were identified, illustrating that despite customers beliefs they had done it all, there remained more to do. Over half of the ECMs had a pay back of less than four years.

The most important question now is: will customers make these efficiency investments? Surveys and self-reporting by the customers suggest they plan to install about half of the ECMs when equipment needs to be replaced.

An interesting, but not surprising finding is that there has been little change from ten years ago in the reasons audited customers give as to why identified, cost-effective measures are not implemented. Customers continue to cite poor payback, lack of capital, low management interest and uncertain futures.

To motivate customers to make improvements, NMPC is setting up relationships with banks and an approved list of Energy Service Companies (ESCOs) for customers needing financing or project management. A desirable and plausible outcome from this effort is that customers will achieve savings at a cost lower than a utility-sponsored program. In addition, all program expenses are removed from the utility's books.

Revolving Loan Fund

In the past, when utilities have offered loans, the money has been budgeted and recovered but not cycled back into the fund. As a result, each year's new budget created a new capital pool for loans expected to be made in that year. A revolving loan fund adds an important re-use dimension. Capital and interest recovered from paid-back loans are cycled back into the fund, thus allowing new participants to borrow money for energy efficiency improvements.

Texas, Oregon and Iowa have extensive track records with revolving loan funds. These states, by combining financing with energy audits and technical assistance, have achieved significant market penetration into institutional markets, including governmental, educational and institutional facilities. In addition, Oregon has had experience with privately-sponsored projects as well.

The Oregon Small Scale Energy Loan Program obtained its capital from general obligation bonds and has made over $250 million in loans, half of which are for renewable energy projects. The Texas LoanSTAR program was endowed with funds from an oil overcharge settlement and is now self sustaining with a pool of $98 million. The Iowa Energy Bank gets its funds from a variety of sources. It has made loans totaling about $9 million to projects costing a total of $240 million. These are not minor investments.

Over a period of years, a utility could achieve self-sustaining results through a regular appropriation. The city and municipal utility of Oslo, Norway has done just that. There, a 1.6 mill/kWh surcharge (representing a 2.9 percent impact on a 5.5¢/kWh electricity cost) created, over a ten year period, a capital fund of $149 million. Loans have been made to over 20,000 utility customers for $112 million. Since the fund is now self-sustaining, the surcharge has been discontinued.

System Benefits Charge

A system benefits charge is very similar to the Oslo, Norway approach and addresses the issue of how to provide energy efficiency (and other public benefits) as industry competition changes the way customers purchase power. A system benefits charge, charges for use of the distribution wires. That way it is immaterial whether a customer buys power from the local utility or from an outside supplier. A full discussion on this approach to funding energy efficiency is included in the *System Benefits Charge* chapter.

CONCLUSIONS

There has been less experience with low cost/no cost approaches to energy efficiency than for more traditional utility programs, and it is still too early to draw firm conclusions. A summary at this time suggests the following.

- Low cost/no cost programs address the utility's direct expenditures on energy efficiency but do not address the problem of lost revenues. Where the lost revenue problem is large, low cost/no cost efficiency programs have only a limited ability to address rate impact problems of energy efficiency.

- There is no free lunch. Low cost/no cost programs will produce lower levels of energy savings than traditional programs. This occurs both because low cost/no cost programs generally have lower market penetration and because they generally do not provide as comprehensive a group of efficiency measures.

- Some market segments appear less amenable to low cost/no cost approaches. For example, there are few good examples of low cost/no cost programs for small commercial, industrial and residential customers.

- Market transformation programs represent a new and fairly promising alternative to utility rebate and incentive programs. In addition, they may be good candidates for being run by non-utilities, perhaps as part of the administration of a system benefits charge.

Renewables in a Competitive Environment

The competitive industry and movement towards it will affect the mix of energy resources acquired now and for the near future. This chapter looks at how the impact of competitive forces is likely to exert itself on renewables.

WHY RENEWABLES?

Renewable energy relies on available and *renewable* resources, such as wind, sun, biomass (wood and green plants) and water to produce electricity. Electricity generated from these sources possesses a number of attributes that differ from power produced from fossil and nuclear fuels.

- Environmental impacts, particularly air emissions, are typically much lower. Relying in part on renewables aids in complying with existing environmental laws and provides a measure of protection with regards to future environmental requirements, such as those related to greenhouse gases.

- Fuel costs for renewable resources tend to be stable and low or free.

- By diversifying the energy mix, renewables reduce a utility's financial risk.

- Renewable technologies offer size and construction time flexibility. Production units are small and modular which allows incremental unit purchases to be made as needed.

- The development of local renewable resources stimulates the local economy.

It is no surprise opinion polls consistently find the public favors renewable energy over other energy options. Public utility commissions in many states also have backed the development of these resources precisely because of the valuable features they offer. In turn, supportive state policies have had a strong and positive impact on both the progress and costs of these technologies. Support for wind development in California has profoundly affected the cost of wind energy. In the past 20 years, costs have fallen dramatically from over 20¢ per kWh in 1975 to the current 4.5¢ per kWh. At the same time, the technical performance of wind turbines has greatly improved. State policy support of wood-fired energy in Maine has turned out to be economically advantageous for the northern Maine economy while costing no more than the resources they replaced. A little policy support goes a long way when it comes to increasing the use and development of renewable resources.[1]

HOW WILL INCREASED COMPETITION AFFECT RENEWABLE DEVELOPMENT?

Increased reliance on competition in the utility industry can affect renewables in a number of ways, some of which may be beneficial and others which may not. Factors that might favor renewables include:

[1] For a discussion of the barrier to renewables and policy options see *Renewable Energy: Barriers and Opportunities, Walls and Bridges.* The World Resources Institute. 1992.

Customer preference. Consumer polling in general and market research performed in conjunction with green marketing activities consistently find a large number of customers (especially, but not exclusively, residential customers), prefer renewable energy to other sources of power. Other consumers are aware of environmental issues but unaware of how their electricity is produced. When informed about electricity production, a large number of individuals polled say they would choose renewables if given a choice, even if the price were higher. A more competitive industry structure could either make renewables accessible to consumers or at least make consumer preferences a more important decision-making factor for existing utilities.

Increased price volatility. Industry structures that include market prices for new and existing generation will experience more price volatility than consumers are accustomed to. For example, consider what happens to electricity prices if natural gas prices double, and gas accounts for 20 percent of the generation mix. In a cost-of-service environment, prices go up by less than 20 percent. In a fully competitive setting, market prices, or marginal cost could go up by the full 100 percent. Customers seeking to avoid the risk of significant price changes will be attracted to the price stability provided by renewables.

Unbundling of costs. It has been a constant struggle to gain widespread use of avoided cost analyses to accurately measure the capacity and energy value of renewables. Even rarer are examples where utilities have included distributed benefits and risk and diversity value in their resource selection process. As industry structures move in the direction of competition, costs will become increasingly unbundled and location specific, and the value of renewables will become more apparent to utility and/or retail customer.

Reallocation of environmental risks. In a cost-of-service environment, the risk of future environmental costs (e.g. the cost of retrofitting pollution control equipment or paying pollution taxes) is borne by consumers. In a competitive market where generators receive market prices regardless of their specific costs, this risk is borne by investors. This will tend to favor renewables.

Other factors in an increasingly competitive world that do not benefit renewables include:

Price impacts. Taking into consideration factors such as risk reduction, diversity benefits and price stability means the price of at least some renewables will be higher than the price of alternative power supplies. The increase in price may be small (probably less than the value the buyer might place on an insurance policy), but the near-term, one to five year focus on reducing electricity prices suggests utility buyers are more likely than not to choose to go uninsured.

Price patterns and planning horizon. Even if the levelized price of renewables are equal to those of fossil supplies, most renewables will have relatively high capital costs. This means that despite cost advantages in later years, renewables will be more costly in early years. This price pattern will be a disadvantage to renewable resources in a world focused on near-term prices. It also means renewables look best if planning horizons and related financial commitments are relatively long, 15 years or more. However, as a general rule, the more competitive the industry structure the shorter the planning and contracting period.

Market risk. The flip side of price stability for consumers is market risk for generators. Generators face two types of risks in a competitive market: the risk that market prices will move differently than expected and the risk that market prices will move in a different direction than costs. A generator selling power at the prevailing market price will be at little risk if costs move up or down with market prices. The second risk, though, is much more serious. If market prices go down but costs stay constant, the costs are stranded and because the environment is competitive, the stranded costs will not be recovered. This situation favors natural gas because gas prices and market prices of electricity are likely to move in sync. Generators picking a renewable resource face the risk of gas and electricity prices dropping while the cost of the renewable stays constant. (The converse — gas and electricity prices rising — could happen as well making the purchaser of a renewable the beneficiary.)

Limited direct access. Residential and small commercial customers tend to place a higher value on renewables than other customers. Thus the worst industry structure for renewables is one in which direct access is limited to large industrial customers — the customers who generally have the least interest in renewables.

Research and development. Considerable progress in the development of renewable technology over the past 15 years has brought prices down and reliability up. Driving technology costs down further will require continued investment in R&D. Maintaining investment levels will be a significant challenge as the utility industry becomes increasingly competitive.

POLICY OPTIONS

Exactly how renewables will fare under the final industry structure is far from clear. What is clear is the transition to a more competitive structure will be long and complex, with renewables entering the transition in a weak position. Fortunately, there are a wide array of policy options that can be used during and after any transition.

Green RFPs have been used to target renewable resource development. Competitive bidding has elicited responses for many types of renewable projects and has also driven prices down. California utilities and New England Electric Systems have both used renewable solicitations to locate competitively-priced renewables. The UK, in meeting its non-fossil fuel obligation, has used a series of renewable bids which have had the effect of stimulating the renewable industry. Renewable developers have seen first hand the impact of competition on price. Reductions in price from the first to the most recent bid have been dramatic.

Ontario Hydro is using a Green RFP to help develop renewable energy, and Niagara Mohawk Power is using competitive bidding to find resources for its green pricing program.

Set asides are used by commissions to stipulate that a portion (a percentage or a specific amount) of a utility's power be generated from renewables. For example, Minnesota has specified the development of

140 MW of wind power and has relied on vigorous competitive bidding to satisfy the set aside in the most economical manner.

Performance based regulation (PBR) set renewable targets and tie profits to these targets. Utilities achieving or exceeding a set goal are financially rewarded. Those that fall short are penalized.

There are other ways to use PBRs to support renewables. A portfolio diversity PBR might be structured to provide a bonus for any resource type which composes a small percentage of the total and a penalty, perhaps 95 percent recovery of costs, for any resource dominating the mix. An environmental improvement PBR can target emissions of a specific pollutant, such as carbon dioxide. Rewards or penalties can be set based on a utility's ability to restrict its emissions of the pollutant. In either of these, utilities will be rewarded if they elect renewables.

Standard contracts specify the general terms and conditions under which power is to be purchased. They can be written to accommodate characteristics typical of renewable projects but different from fossil fuel combustion plants. Standard contracts also reduce the time spent negotiating each project and can reduce development costs.

Transmission and distribution costs, as part of the full cost of generating and delivering power, should be made a part of the resource selection process. When this is done, situations will emerge where acquisition of a renewable is the least expensive resource option. Line extension policies for remote customer service drops should require the cost of using a renewable resource be compared to the cost of extending a line to the same location.

Green pricing recognizes there are many customers who want a greater portion of renewables included as a part of their resource mix and are willing to pay a higher price for it. The reason for this support ranges from a commitment to the environmental benefits derived from avoiding fossil fuels to a preference for the smaller price volatility of renewables.

Some utilities are offering green pricing to their customers. Participants agree to pay a price premium for a renewable, for example a wind energy or photovoltaic project that is not quite cost effective. The price premium is the difference between the cost of a selected renewable and the utility's avoided costs. Only customers who choose green pricing pay the higher price premium.

To be considered successful, high levels of participation are not essential. Even a small segment of the consumer population, say five to ten percent, can vastly increase the amount and percentage of energy produced from renewables, when compared to today's resource mix.[2]

System benefits charges change the collection mechanism for some costs currently included in rates. If commissions want utilities to obtain a portion of their energy from cost-effective renewables, any costs associated with this effort may be collected as a charge for use of the distribution wires and dedicated to renewable development. A charge for

[2] More information about green pricing can be obtained from the Regulatory Assistance Project.

renewable acquisition can be based on what a utility is currently spending or at some higher (or lower) level selected by the commission.

A system benefits charge can be placed on either customers or generators since both rely on the wires. Any charge placed on the generator would be passed onto customers.

Portfolio standards or renewable obligations could also be placed upon all suppliers as a condition for doing business in a state that sets a percentage of generation to come from renewables. To accomplish this efficiently and not require that every power supplier become a renewable energy developer, these requirements should be tradeable. Tradeable requirements would also help keep costs low.

Net metering can encourage customers to install renewable technologies on their own initiative. Residential or commercial rooftop photovoltaics or farm windmills are examples of what some customers may be motivated to invest in. With net metering, the electric meter runs backwards when power is produced from an on-site renewable in excess of the customer's consumption and forward when the customer consumes power through the grid. When customers produce more than they consume, the utility purchases the excess at the appropriate avoided cost.

CONCLUSION

Until it is better understood how renewables will do in the competitive world, commissions should adopt policies that continue to support their development. Supportive policies will benefit the environment and lower production costs of emerging technologies. If it turns out renewables fare well on their own, policy support can be phased out. Commission support and policies will be crucial during the transition period, a time when renewables are particularly vulnerable.

Implications for Nuclear Power with Full Competition in the Electric Business

This chapter provides a framework for discussion of whether government should intervene to alter the prospects for nuclear energy in a competitive electricity generation market. It questions whether nuclear power plants can compete on a privately-owned, stand-alone basis (i.e., separate from transmission and distribution assets), and concludes they probably cannot. It presents reasons why government might want either to override this conclusion or to assure it is realized gradually. It ends by discussing specific types of governmental intervention that might be employed if intervention is considered desirable.

CAN NUCLEAR POWER COMPETE?

> ".....My point is that we never worked out how we would deal with these kinds of problems because, in assuming a quick and fairly painless transition to a market environment we have not squarely considered what would happen if our nuclear capacity really could not compete".[1]

Twenty-three years have passed since the Atomic Energy Commission forecast that the U.S. would need 1000 nuclear power plants by the year 2000; a forecast that carried with it a commitment to nuclear parks, housing some twenty power plants surrounding a breeder reactor and a reprocessing plant. Today's quarter-century forecasts may not be any better than that one, but we now know a lot more about the year 2000: One hundred power plants, no nuclear parks, no breeder reactors, no commercial reprocessing.

No industry has ever imploded so dramatically or so expensively. At the core of this implosion is the phrase "market reality". More than by the wastes, by the safety issues, by proliferation, credibility or by overzealousness, nuclear energy has been damaged by its costliness relative to other sources of energy.

Since the electric industry, especially the generating industry, is increasingly dominated by the types of market tests nuclear energy has been failing, what are the future prospects if nuclear power must compete on an equal basis with all other sources? Approaching this question requires a review of the nature of the market tests nuclear power has been failing.

Repeatedly, from 1981 onward, utilities concluded the economics of completing and operating a nuclear plant in advanced stages of construction were no better than slightly favorable. Several such plants were canceled. The most extreme case (in terms of minimal remaining construction cost and certainty of operation) was Shoreham, where Long Island Lighting Company's (Lilco) 1988 studies showed a $400 million present value benefit to consumers to operating the plant, as long as oil prices rose at an annual rate of about four percent until 1992 and at six percent thereafter. Even then, Lilco customers would not have broken even until about 2003. "Benefits"

[1] Speech by Harlan Dellsy, Vice-President, Commonwealth Edison, "Nuclear Competition," Harvard Energy Policy Group, New Orleans, 1/27/95.

would have accrued to consumers in the next century. Had accurate oil price forecasts been used, the present value of operating Shoreham for its licensed life would have been negative. Of course, it was argued that these studies were improperly done (even by Lilco) to justify the settlement, but market corroboration came swiftly.

During the years 1988-1990, all New York utilities were required to solicit bids for new capacity (to avert the prophesied power shortages of the mid-1990s). In two of these auctions, capacity was bid from recently completed nuclear units. Both bidders (owners of Seabrook and Limerick), lost to bids from gas fired plants that had not yet broken ground. Later a Seabrook owner Eastern Utility Associate Power (EUA Power) who owned no other assets, was forced into bankruptcy because it could not sell the power at a price that covered operating costs plus its share (about $1500/kW) of the construction costs.

Meanwhile in the United Kingdom, the government set out to sell its generating stations (including nuclear) to the private sector. Despite fixed price contracts for decommissioning and waste management with the government-owned, British Nuclear Fuel Laboratories, the managers of the nuclear assets sought government guarantees to cover the other economic and safety risks of nuclear power. When these were refused, the attempt to sell off the nuclear plants was abandoned. They remain in the government-owned corporation, Nuclear Electric, which has announced an intention to try to sell off at least the newer of the nuclear units again in 1996.

Finally, as plant after plant has faced major milestones requiring new investment or renewed public confidence, managements have preferred to retire the units. This has been the fate of San Onofre I, Yankee Rowe, Rancho Seco, Trojan and Shoreham. In none of these cases has the utility had economic reason to regret its decision.

A few cases point the other way. Rochester Gas and Electric and Maine Yankee have recently undertaken replacement or repair of their steam generators under circumstances that shift some (but not all) market risk to their shareholders. Perhaps more interestingly, the Great Bay Power Company has arisen from the ashes of the EUA Power bankruptcy and has actually attracted $35 million in new capital for a majority interest in EUA Power's 140 Seabrook megawatts, to be operated as a wholesale marketer in New England. Even at this price, which is less than 5 percent of the per megawatt costs of building Seabrook, profitability at present NEPOOL spot prices is not assured, even if Seabrook runs well. Still, this seems to be the only case in which investors for private, stand-alone nuclear capacity have been found at all.

Furthermore, the costs of nuclear generation have fallen significantly in the last decade. Labor costs have dropped. Capacity factors have risen. Unexpected shutdowns have been substantially reduced, which enhances safety as well as economics. Some portion of these measures of operational improvements are undoubtedly the result of the shut down of chronic under performers such as Trojan, Rancho Seco, Fort St. Vrain and San Onfre I. However, a wide gap now separates the better performing units from those at the bottom of the ladder, and investors no doubt observe that several of those now at the bottom were once at the top. More ominously from an investor viewpoint, the cost of alternative forms of generation has fallen even faster during this period.

Consequently, even though the marginal costs of a smoothly running nuclear plant are within competitive range of fossil fuels, it is entirely plausible that full competition among all generating units dooms most, if not all, nuclear plants. Put another way, it seems more than likely a utility confronted by a mandate to divest all generation could not give away its nuclear plants to a private entity, even assuming the NRC's requirements on financial qualifications for regulated utility ownership could accommodate such an ownership change. If this proposition is incorrect and plants can change hands, there remains the issue of stranded cost; how to allocate the difference between book value and a sale price as low as $0. If, on the other hand, the analysis is correct, then government must either temper the forces of full competition or be prepared to do without nuclear generation.

Indeed, the California Public Utilities Commission seems to have concluded as much in its proposal to leave the nuclear units in utility hands, packaged together with the hydroelectric units for ratemaking purposes. New York's utilities have recently made state solicitude for the nuclear units — "which," they say, "because of their unique characteristics, cannot be operated on a deregulated basis" — an explicit precondition for their willingness to move even toward their singularly mild version of wholesale competition. In short, considerations that might justify government intervention need close scrutiny.

JUSTIFICATIONS FOR GOVERNMENT INTERVENTION

> "I think the government has to do something about the market. I don't think it can be left to the private sector."[2]

Among the possible justifications, the following stand out:

Safety

Even though efficiency improvements to date have generally improved safety levels, ample experience from other industries demonstrates that unmitigated competitive pressure can create potential safety problems. Former NRC Chair Ivan Selin told the American Nuclear Society in November 1995 that "....we must be sensitive to the unprecedented competitive pressures wheeling could impose on utilities which in turn could lead to significant safety concerns at some nuclear power plants.....We are concerned that management in a number of utilities.. . not across the board...will be tempted to cut corners or reduce those capital investments necessary to maintain equipment in top shape....One worrisome example involves measures being taken by some licensees to reduce cost through scheduling preventive and corrective maintenance during power operations....without assessing the risk consequences".

This is a particularly difficult issue. For one thing, Mr. Selin and others have concluded economic pressure has, to date, tended to improve safety. Just when such pressure will

[2] Lord Weir, as quoted by Ross Tieman, "Nuclear Power Industry Seeks Guaranteed Market," The Times July 27, 1994: 24.

become a negative factor is impossible to pinpoint with confidence. Furthermore, the remedy is difficult to fashion. Continuing pressure on operating costs is inevitable under any rational plan for future nuclear ownership and operation. Any of the benefits from nuclear operation can eventually be achieved from other sources, including end use efficiency, and the cost of those sources continues to fall. As long as nuclear plant owners and operators must face the possibility — one that did not exist until relatively recently — that they can be put out of business no matter how well they perform, pressure to cut corners will exist.

Reliability

Given the concentration of nuclear power in some parts of the country, transmission capacity is inadequate to make up for a rapid shutdown of all nuclear capacity. Furthermore, if nuclear energy were replaced entirely by the cleanest fossil alternative (an unlikely scenario, since coal, energy efficiency and renewable energy sources would fill much of the void), U.S. natural gas usage would rise by some 30 percent.

Of course, the interplay between reliability and economics is dynamic. As some plants shut down, the value of others would rise. Whether this process would make some nuclear plants competitive for the long run — as distinguished from merely assuring a phased shutdown — is an open question.

Environmental Impacts

To the extent nuclear energy were replaced by fossil fuels, U.S. CO_2 emissions would increase to an extent incompatible with our commitments as a signatory to the 1992 Convention on Global Climate Change and with the Clinton Administration's 1993 Climate Change Action Plan. According to the Nuclear Energy Institute, "On an annual basis, the Nation's 109 nuclear power plants help prevent the emission of 133 million metric tons of carbon....(an amount) greater than the 108 million metric ton reduction called for by the Clinton administration to stabilize greenhouse gas emissions to their 1990 level by the year 2000. For every one percent increase in the annual capacity factor of the 109 U.S. nuclear plants, carbon dioxide emissions from the electric industry are reduced by approximately 2 million metric tons".

The NEI paper continues, "In 1993, U.S. nuclear power avoided utility emissions by 4.7 million tons of sulfur dioxide and 2.2 million tons of nitrogen oxides....As a matter of comparison, the Clean Air Act Amendments of 1990 call for annual reductions of 10 million tons of SO_2 and 2 million tons of NOx by the year 2000". One need not accept these estimates as precise to see that the near-term air impacts of shutting many nuclear plants down rapidly would be substantial, especially when the probable increases in airborne mercury and toxics are added to the calculations.

Ironically, because many, though not all, the externalities attributable to nuclear energy have (the Price Anderson Act notwithstanding) been internalized (through, for example, the waste and decommissioning charges), the nuclear utilities - who number in their midst many of the most vocal critics of state attempts to reflect externalities in the price of power - could be among the principal beneficiaries of such calculations, provided that nuclear power could compete with other non-fossil sources.[3]

Fuel Diversity and Security

Fuel diversity and security are really other types of externality considerations. However, they are strongly endorsed in every National Energy Strategy document in the last three decades. They are also reflected in most state decisions certifying the need for nuclear power plants. These calculations were not subjected to criticism until state regulators in recent years took the further steps of quantifying them and applying them to end-use efficiency and to renewables.

No jurisdictions seem to be headed rapidly toward a chips-falling-where-they-may approach to restructuring and competition. Under any likely combination of the foregoing considerations with the imperatives of the political process, an extended transition for most nuclear units appears likely. However, a transition is not the same as a preference, and the mechanisms chosen for one will not necessarily suit the other.

MECHANISMS FOR GOVERNMENT INTERVENTION

> "....The technology was promoted, at considerable expense, for non-economic reasons. Therefore solutions to the economic problems created now that the original motivations are no longer relevant cannot rely on private market processes exclusively."[4]

The decision among mechanisms for intervention will rest in part on whether intervention is viewed as transitional or long term, in part on the externality value attached to nuclear power and in part on whether that externality value is viewed as being unique to nuclear power (as distinguished from being available through any non-fossil or non-foreign energy source). The mechanisms must also account for the level and predictability of the future costs of nuclear generation.

The categories of potential intervention include the following:

1. Measures to reduce uncertainty, including a clear national policy on an interim waste repository and license extension and clarification of the ratemaking treatment of decommissioning costs[5]. These measures are desirable regardless of the competitive status expected for the nuclear power plants. Other alternatives to reduce uncertainty include governmental assumption of liability for

[3] However, they may question whether they would be allowed the benefit of such calculations. If the Mass. DPU had applied its CO_2 adders to the decision to close Mass. Yankee, the plant would probably have continued to operate.

[4] Dr. Edward P. Kahn, Lawrence Berkeley Laboratory, "Preparing for the Inevitable: The Nationalization of the U.S. Nuclear Industry in a Competitive Electricity Market," The Electric Industry in Transition, New York State Energy Research and Development Authority, 1994 ed.: 199-212, 207.

[5] Decommissioning costs vary little after the early years of operation. Therefore some argue that any estimated difference between reserves and actual costs should be treated like stranded investment rather than being an operating cost of a competitive entity.

waste and decommissioning costs in excess of a fixed ceiling, thereby providing investors with a measure of certainty as to the full extent of their exposure. This is, of course, one of the functions served by the Price Anderson Act with regard to nuclear accident liability.

2. Measures to encourage or mandate different patterns of nuclear power plant ownership, including aggregation into a few large private entities, into quasi-governmental authorities or into outright government ownership. These proposals, which include operating entities that would not necessarily own plants, have been discussed since Three Mile Island. Considerations of economy and safety are said to weigh against the small utility that owns one or two reactors at a single site. In addition, the ability of public authorities to issue tax exempt debt is attractive in the context of these capital intensive units.

   Unless nuclear plants remain under utility ownership, the NRC's regulations relating to financial qualifications[6] may create pressure toward aggregation of some sort, for it would be difficult for a non-utility entity to make the requisite showing as it is currently worded. However, such combinations cannot be put together on a transitional basis. If they make sense, it can only be in the context of a societal expectation of operating a substantial number of plants for at least the rest of their licensed lives.

3. A requirement along the lines of the United Kingdom non-fossil levy, which was essentially a mandate to purchase from the nuclear units that could not be privatized. This is the most flexible approach. It can be adapted to different forms of ownership, to a transitional or long-term presence and to different externality values. The British government has discussed a possible phaseout of the levy as early as 1997. Although different in concept from a stranded asset charge, it is not so different from a "benefit charge" and could be implemented in parallel. Since DSM and renewable resources are seeking a place at the same non-fossil table, nuclear proponents would have to make their case in competition with other claimants. This competition would shed some light on the prospect of interest in new nuclear units in the next century.[7]

---

[6] 10 C.F.R. 50.33(f)(2) requires a non-electric utility applicant for an operating license to show that it "possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for the period of the license."

[7] See, for example, John Douglas, "Reopening the Nuclear Option," EPRI Journal (December, 1994), which states, "After more than 10 years of intensive effort, EPRI's and the nuclear industry's program to develop the next generation of advanced light water reactors is coming to fruition....By the time American utilities are expected to begin ordering new baseload plants again, around the year 2000, their options will include four standardized ALWR designs pre-certified by the Nuclear Regulatory Commission--plants that can be built with a high degree of confidence with respect to schedules (42-54 months) and total costs ($1300-$1475/kW)".

Performance Based Regulation
A Policy Option for a Changing World

While all agree that market competition can provide excellent incentives to cut costs and promote innovation, competition will not wholly preclude a role for regulation and the need to look for ways to improve regulation. This is true for two reasons. First, only the generation part of the industry can be competitive (see "Why A Generation PBR? box"). Second, two major parts of the industry, transmission and distribution will remain a natural monopoly for the foreseeable future. While there is considerable discussion about competition in generation, unless and until the necessary structural changes have been made, deregulation of generation should not be an option.

As the industry changes, regulators must decide whether and how to reform regulation. Traditional, rate-of-return regulation evolved to fit a monopoly structure designed to support major investments in large, central station generating plants and is less well suited for today's utility industry. The challenge before regulators now is to consider reforming regulation in ways that not only improve the status quo but also lead the way to an even more competitive future.

AN ALTERNATIVE — PERFORMANCE BASED REGULATION

Performance based regulation (PBR) is a concept presented as a regulatory alternative. Rather than frequent reviews of utility costs and setting rates to reimburse utilities for what they spend, PBR takes a longer term view and focuses on how utilities perform. In a well-designed PBR, good performance should lead to higher profits. Poor performance should lead to lower profits.

The modern roots of PBR in electric utility regulation can be found in NARUC's 1989 Resolution which calls for ratemaking practices that align utilities' pursuit of profits with the implementation of their least-cost plans. Section 111 of the Energy Policy Act of 1992 subsequently embraced this policy.

PBR may be best described as a new term for an old concept. This means that by considering PBR, regulators are not going back to the drawing board. Examples of existing mechanisms similar to PBRs include:

Stay outs. Cost-of-service ratemaking can create opportunities for the utilities to either increase (or lower) earnings when they are given a fairly long regulatory stay-out period between rate cases.

Decoupling. Revenue-per-customer decoupling schemes in Washington and proposed in California, by setting an amount to be recovered for each customer, give utilities the opportunity to increase efficiency and earnings.

Fuel efficiency incentives. Fuel cost adjustment clauses have been structured to tie the utility cost recovery is tied power plant performance rather than to the size of the checks the utility writes to its suppliers.

CREATING PBRS THAT WORK

Creating or evaluating a PBR consists of three basic steps:

Identify the goals. The first step of any successful PBR is to identify the goals to be achieved. This might include the following:

Cost cutting. Regulators can substantially increase the incentives for utilities to reduce their costs, with a significant portion of the savings passed through to customers.

Streamlining regulation. Simplifying the regulatory process allows utility management to turn its full attention to improved performance in all areas of its business and away from managing regulatory relationships.

Restructuring risk exposure. In many cases, there is a wide difference between utility management's perception of a risk and the actual financial consequences resulting from a decision. Management may worry that an investment may be disallowed as imprudent. Customers, on the other hand, rarely care whether a decision is prudent as long as it turns out to be right. PBRs can allow a more thoughtful allocation of risk between utilities and customers.

Insuring good performance. PBRs can be extended to meet other performance goals as well, such as acquiring a clean, diverse resource mix, achieving an acceptable level of reliability and providing strong and effective customer service.

Get the structure right. The structure of a PBR defines the incentives a PBR produces. Once the goals are set, a PBR structure can be created to focus on those goals.

For example, one of the major choices (discussed more fully below) is whether a structure should be centered on electricity prices or utility bills. A structure focused on prices produces powerful incentives to cut costs, increase sales and reduce cost-effective conservation. Structuring the PBR around bills, on the other hand, does not diminish the incentive to cut costs but creates an incentive for cost-effective energy efficiency.

Get the numbers right. Even if the structure is right, if the numbers are not right, there is a good chance customer bills will be unreasonably high or utilities' financial health will be threatened. The right PBR structure, for example, might be $X per customer plus inflation minus productivity. Getting the numbers right means starting with the right "X" and using the right inflation index and productivity factor.

One reason it is especially important to get the numbers right is that PBRs will probably be considered first for utilities that already have relatively high costs. High costs may be a result of high fixed costs that are likely to go down relatively fast through amortization of cancelled plants, front-end cost recovery of recently added expensive plants, etc. Where costs are high, it is probably easier to control cost escalation. In such a situation, locking in current costs plus an average level of inflation will be much too generous to utilities and too costly for consumers. To support cost cutting and not the status quo, caution must be exerted.

PBRs are not 'one-size-fits-all.' An approach that works well for one utility, say a distribution company with unacceptably high average rates, may be quite different from the approach one would adopt for an integrated utility entering into a large resource acquisition program.

It may also be desirable to have separate PBRs for each aspect of a utility's business: generation, retail distribution and transmission. Separate PBRs that match the industry structure desired in the future may have the effect of accelerating the time it takes to achieve the actual structure.

Why A Generation PBR With Competition Around The Corner?

There is a long distance between saying generation can be competitive and making it competitive. Before market competition can substitute for regulation, certain elementary conditions must be present, including:

- An adequate number of competitive generators
- Relatively easy market entry for new generators
- Access to the transmission network at reasonable costs
- Institutions to facilitate trading and the reliable operation of the power grid

The presence of these conditions assures that a competitive market for generation is free from manipulation by sellers. Experience from other countries and other industries in this country shows that separating generation and forming large regional independent transmission companies, with the necessary transmission pricing and access rules, are likely prerequisites to establish a competitive industry.

PBRS TO REFLECT ENERGY EFFICIENCY AND OTHER PERFORMANCE GOALS

Carefully designed PBRs can also create mechanisms to achieve energy efficiency, resource diversity and environmental performance.

Energy Efficiency: Bill Cap Versus Rate Cap

As commissions consider alternative ways to set revenues and lower short-term costs, some such as Niagara Mohawk have turned to rate caps. Others such as San Diego Gas and Electric and Southern California Edison have looked to bill caps. Both have proposed features that stretch out the period between rate cases, thereby creating stronger incentives to avoid cost increases or pursue cost savings.

Bill caps and rate caps, however, produce very different incentives. Rate caps provide strong incentives to cut costs, but they also provide utilities with very powerful incentives to promote electric use and equally strong disincentives to DSM. This pro-sales, anti-DSM bias is similar to the biases of traditional regulation, without decoupling or a lost revenue adjustment, but the effect is even stronger precisely because the regulatory lag period is extended. Because rate caps are clearly inconsistent with cost-effective energy efficiency, they should be avoided except in very limited situations, such as wholesale electricity sales where investments in DSM are not an issue. (This issue is not a problem in the telephone industry where rate caps have been in use for some time because there is nothing in telecommunications that resembles cost-effective energy efficiency.)

Bill caps, on the other hand, produce the same cost cutting incentives as rate caps but very different and much better incentives for energy efficiency. Bill cap PBRs are a logical choice for retail sales (sales to final users electricity).

A simple bill cap PBR consists of four basic elements:

1. Following a rate case which looks at the usual cost items and customers served, an allowed base revenue per customer (RPC) is set at a reasonable level. These, with certain adjustments, remain in place for a number of years, thus stretching out the regulatory lag period.

2. Once a year, the RPC is adjusted by setting a growth rate for RPC. The simplest approach allows a growth based on some broad inflation measure, less adjustment for productivity improvements. One example would be to let the RPC rise by the annual change in the Consumer Price Index less two percent for productivity improvements. Other approaches might base the increase on the change in other electric utilities' costs.

3. Often, the utility is allowed to directly pass through certain costs, typically referred to as "exclusions" or "Z-factors." These costs are generally desirable expenditures and/or outside the utility's control. Examples might include the costs of DSM, R&D and Superfund site cleanups.

4. Adjustments can be made to accommodate changes in customer usage. For example, to the extent customer use under a cap falls (or rises) outside a specified range, there would be a rebate (or surcharge).

A Sample Bill Cap Mechanism

A typical bill cap mechanism is generally structured:

$RPC_{Year1} = RPC_{Year\ t-1}$ x (1 + i- p + adj.) + (ªUPC x MEC) where

RPC is Revenue per Customer
i is a measure of inflation such as the consumer price index or a utility price index.
p is a measure of expected productivity gain, for example 2 percent per year.
adj. are adjustments to reflect items such as exclusions, targeted incentives or penalties, and any rebates or surcharges to reconcile over- or under-recovery of allowed revenue.
ªUPC is change in average kWh use per customer
MEC is the marginal energy cost

By following these steps, the net effect is that the utility will have a specified amount of money to serve customers' needs. If they spend less, their profits rise. But profit will hinge on cost control, not customer usage. This reduces the disincentive for DSM and the incentive for load building.

Resource Diversity: Portfolio PBRs

While rate and bill cap PBRs are proposed to lower short-term costs, IRP and cases involving power plant construction raise a different and more subjective set of issues the need to acquire a good, diverse, low-cost set of resources. Here, the major challenge is to come up with performance based measures that fairly reward (or penalize) utilities that achieve (or fail to achieve) the established goals. These cases call for a different PBR approach, and portfolio PBRs have emerged to fill this niche.

To design a portfolio PBR, the first step is to define the goals of resource acquisition as clearly as possible and decide how to trade off the potentially conflicting goals of low costs, low risks, resource diversity, a clean environment and customer preferences. The specific resource PBR will depend on how these tradeoffs are made.

For example, if the policy goal were to get a specified level of DSM, the PBR might reward or penalize the utility based on whether it achieved or fell short of the goal. If the goal were a diverse resource mix, a PBR might be structured to provide a bonus, say 110 percent of costs, for any resource type which composed a small percentage of the total and a penalty, say only 95 percent recovery of costs, for any resource which dominated the mix.

Fuel Clauses — The Anti-PBR

It is not possible to discuss PBRs without briefly touching on the other extreme — the fuel adjustment clause. Most utilities have fuel adjustment clauses which, for the most part, allow utilities to recover every dollar they spend on fuel and some forms of purchased power. Fuel clauses, particularly the simpler versions, leave the utility with no incentive to control fuel costs. At the same time, they tilt the playing field in favor of high fuel cost options

Fuel clauses also create a disincentive to the utility to operate its units efficiently. If a utility spends money to improve the fuel efficiency of a generator, the money spent on improvements decreases profits, while the savings — the lower fuel costs — are passed through to ratepayers under the fuel clause. Fuel clauses tell utilities that investments that save fuel are not a good expenditure.

There are two potential solutions. The easiest and best is to recover fuel costs in the same manner as all other costs. If this is not feasible, the other option is to sever the link between actual fuel expenses and allowed revenues as fully as possible. Options here include adjusting only for changes in the price of fuel, but not in the generating mix or allowing recovery of only a portion of the variance between expected and actual fuel expense.

Environmental And Other Performance Measures

PBRs can be directed explicitly at environmental goals using targeted incentives focused on specific aspects of utility performance. Prototypes already exist in DSM incentive programs where a utility that acquires DSM at or below avoided cost is allowed to keep a portion of the savings. To target emissions of a specific pollutant, such as carbon dioxide, rewards or penalties can be set based on a utility's ability to restrict its emissions of the pollutant. A simple approach uses a bonus/penalty of $X per ton for variations around the target.

Targeted PBR schemes are not meant to cover the full range of utility performance but can be directed at almost any area of utility performance from average outage hours to customer service.

CONCLUSION

It is not by chance that the PBR discussion is occurring amid the debate over increased competition in the utility industry. The PBR route gives regulators the responsibility and the opportunity to define objectives for the industry. This can set the groundwork for just what is expected in a more competitive environment and can provide the best vehicle to articulate what, in addition to low-cost energy services, is important for the industry to provide customers. Even in the absence of competition, PBR offers a simpler and speedier regulatory process; one which emphasizes measurable results and does not depend on the myriad of inputs needed to conduct a cost-of-service study.

While it is too early to say whether PBR will emerge as the primary alternative to traditional ratemaking, it is not too early to begin thinking about what PBRs are and what it takes to do them and do them well.

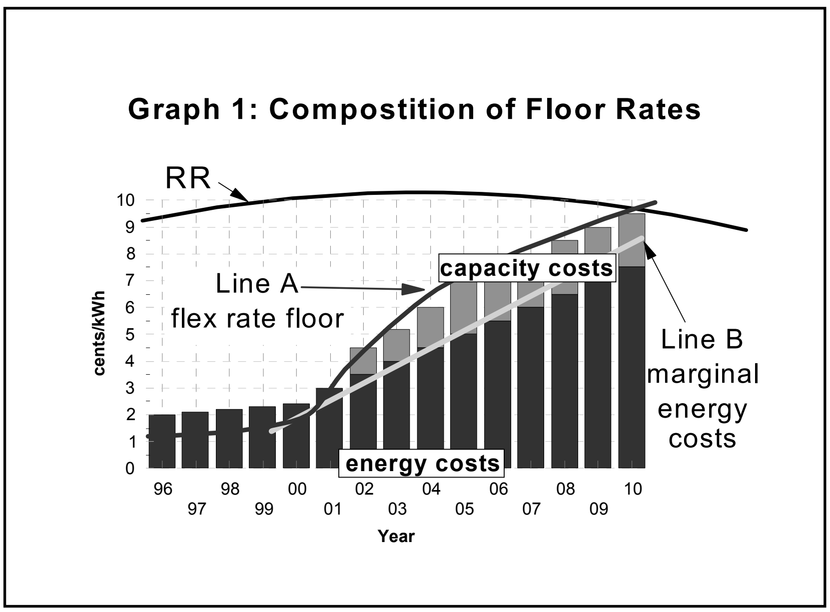
Flex Rates and Rate Design Solutions: Utility Responses to Competitive Pressures

With increasing frequency, commissions are being asked to approve special rate discounts often called flex rates, economic development rates or cogeneration deferral rates for large industrial customers. The ostensible purpose of these rates is to permit utilities to attract new customers, encourage business expansion or retain customers who threaten to close their plant, move it to a different service area or self-generate. Commissions should understand that in approving these rates, they may be postponing competition. Offering discounts to customers who have less expensive alternatives may discourage competition and reduce a customer's interest in gaining access to competitive alternatives.

These rate proposals are often portrayed as offering a competitive price or as a step in the transition to a more competitive electricity market. Rather than paving the way for true competition, the design of the "so-called" competitive rates may instead shield utilities from competitive pressures. For the most part, the short- and intermediate-term focus of flex rates aims at reducing rates for a few years. However, the benefits of competition — overall cost savings through more efficient design and operation of the electric system — tend to occur over a longer time period.

The theory relied upon when designing discounted rates, load retention and cogeneration deferral rates is that the rate floor should cover short-run fuel costs, plus some contribution (sometimes near zero) to fixed cost. This pricing is promoted as being competitive and benefiting all customers because it contributes to fixed costs. In reality, pricing on this basis incorrectly applies market economics to a monopoly industry that continues to build (or buy) power plants based on an obligation to serve rather than customer responses to market prices. The result may be priced below what competitive markets would charge. This exacerbates, not improves, stranded cost recovery — a key obstacle to industry reform.

Graph 1 illustrates why the stranded cost problem can be aggravated with flex rates that assume a short-run marginal cost price floor.



This graph shows a marginal cost line, with the area under the line divided to show the portion of marginal costs that covers fuel (dark bar) and the portion that covers future capacity costs (light bar). (For the sake of simplicity, all the area shown as capacity is the annual capital cost of a new baseload plant added in 2002). The line labeled A represents the price customers would pay if they were to make no contribution to stranded cost. Any rate set below line A increases stranded costs because the utility (or other customers) must absorb the added capacity costs.

Flex rate contracts typically run for short periods of time — one to three years. Graph 1 shows that from 1996 to 2001, the flex rate floor (line A) is the same as the marginal cost. However, during this period, planning and investment decisions are typically made under the traditional planning and reliability rules. These rules assume the utility has an obligation to serve all customers, including the flex rate customer well into the future. To fulfill this obligation, this scenario has new capacity added in 2002.

In 2003, the customer may again seek a special deal based on the same economic principles applied in 1996. However, the new plant, together with its capital costs (sunk as of 2002), have changed the economic picture. Now, line B reflects the marginal energy costs (including the fuel for the new plant). If the customer is allowed to pay only the energy costs, the cost of adding capacity is borne by shareholders or other customers. As the graph shows, charging prices that follow line B rather than line A increases the stranded costs.

Not charging for capacity additions also raises doubts about any assertion that flex rate policies are consistent with competitive pricing. As described in the *Retail Competition* chapter, in a fully competitive retail market, power plants are built in response to market prices or contracts with customers. In such a market, no investor would have constructed a new baseload plant based on a two or three year contract at price B. This is one reason prices to large industrial customers in the UK went up when real competition was implemented.

Potential Flex Rate Problem

When considering flex rates, commissions should consider the following potential issues.

Are they legal? Commissions are expected to set non-discriminatory rates. Discounting rates for a few customers may discriminate against customers who did not receive a special deal, particularly those who compete with the customer receiving the discount.

Who knows if claims are legitimate? While there is every incentive for a customer to argue hard for a discount (and even bluff), commissions typically lack detailed knowledge about the customer's business because customers are reluctant to fully divulge sensitive information. Imposing revenue losses resulting from discounts onto the utility is one tool used by regulators to transfer the burden of proof from the regulators to the utilities. This move also gives the utility an incentive to offer as small a discount as possible.

While in theory this is a logical step, there are two reasons to be skeptical about this solution. First, this is an easy policy to implement when discounts are awarded between rate cases, but it is very difficult, if not impossible, to assure that revenue loss will continue to be allocated to shareholders once the utility files its next case. Second, if the utility is (or would otherwise be) over earning, requiring shareholders to absorb these revenue losses merely takes what would be a rate reduction for all customers and allocates it to a small class of customers. This means that adopting special rates on a case-by-case basis will result in inconsistencies with rate design.

Rate discounts offered to one customer will be sought by others. Once commissions say yes to one customer, they might find themselves on a slippery slope where it gets increasingly difficult to say no to subsequent requests.

What is the net impact on jobs? If flex rates result in raising the rates of other customers, those customers will become less competitive. The number of jobs created (or maintained) by offering a low rate to one customer may be offset by jobs lost from other customers who are paying more.

Flex rates are anti-competitive. Special rates are potentially both discriminatory and anti-competitive. By offering uneconomical low rates to customers with legitimate competitive alternatives, a utility squeezes out competition. This is never desirable, particularly if other customers are subsidizing the discount.

Minimum Standards For Granting Discounts

Despite these issues, commissions are granting flex rates, in part because they worry that if they deny a flex rate and a large employer leaves the state, they may be blamed. If offered, discounts must, at a minimum, recover marginal fuel costs, capacity investments and transmission and distribution charges and should include as much of the strandable cost as possible. In addition, contract terms should specifically notify customers that no capacity additions are being planned for them (except to the extent flex rate includes future capacity costs), thereby making them responsible for the full incremental costs of service in the future. This protective measure will rely on ongoing enforcement which will vary from state to state and from time to time.

Flex Rates And Stranded Costs

A decision to approve flex rates should be done knowing that such rates have the potential of seriously delaying considerations of restructuring and unfairly allocating uneconomic costs. When choosing to offer flex rates, utilities often agree to assume a portion of their stranded cost liability. While a commission may want the utility to bear all or a share of the uneconomic (stranded) costs, doing so on a customer-by-customer basis is not fair to customers who do not have the flex rate option. A principled approach would first determine which portion of the stranded cost should be absorbed by the utility. Rather than allowing that amount to be included as part of a flex rate package, it would instead be applied across the board to lower the retail rates of all customers.

From Surrogate to Midwife: The Changing Role of Utility Regulation in the 1990s

Since its inception at the turn of the century, utility regulation has operated on two levels: the textbook model and the smokescreen. On the textbook level, it has functioned as a surrogate for competition, bridling impulses toward consumer abuse that inevitably crept into monopolies whose only need to compete was for investor capital. On the smokescreen level, it has functioned quite differently, acting as a legitimizer of monopoly behaviors that the public, in the absence of governmental approval, would never accept. This latter role was explained at the outset by Richard Olney, President Cleveland's Attorney General, in his memorable 1892 defense of regulation to utility executives:

". . .[regulation] can be of great use to [utilities]. It satisfies the popular clamor for a government supervision. At the same time, that supervision is almost entirely minimal. The part of wisdom is not to destroy the commission, but to utilize it."

Over the past quarter century, both of these irreconcilable regulatory approaches have been yoked state and federal regulatory commissions and staffs in uncomfortable harness. The onset of competition will heighten the tensions between them as the public comes to demand a different type of regulatory performance in a world where customer preference supplants commissioner preference as the star by which utility executives must steer.

NEW SKILLS NEEDED FOR REGULATORY ACTION

While some will argue that present circumstances already justify substantial cutbacks in regulation, a convincing case can be made for more, not less regulatory scrutiny in the transition period. This increased level of regulatory effort will require skills and techniques different from those emphasized in the past. To acquire these, commissions will need to review not only utility activity but also their own mission, practices and personnel to assure that all are well-suited to the challenges that lie ahead.

Incremental changes over the last twenty years have brought most state commissions a long way from the traditional rate case. Some functions — primarily transportation — have been moved or dropped. Others, such as integrated resource planning, demand-side management program evaluation, environmental impact analysis and avoided-cost projection, have been tacked on. Overall, the legal role has diminished somewhat, while the role of analysis — particularly economic analysis — has advanced.

In the next few years, these trends seem certain to accelerate, with this acceleration expanding, not contracting the role of the commission. Commissions will be expected to function as architects and enforcers of competition, as designers of performance based regulation and as protectors of consumers during a turbulent transition. At the same time, the public will continue to expect protections from environmental degradation and monopoly abuse. Indeed, the greatest threat to competition and deregulation seems likely to come from indignation and backlash that have already accompanied the creation either of a deregulated monopoly (such as cable television in the 1980s or small market airlines) or of windfall profits and excessive executive monetary self-congratulation (such as has recently occurred in Great Britain).

To adapt to a changing mission, commissions must also review the mixture of regulatory techniques they employ. Both in rate cases and in broader rulemakings, adjudicatory and other formal models are being replaced (or at least being extensively supplemented) by negotiating formats. Public participation is also being redefined away from the somewhat intimidating and unproductive formal hearings and toward more effective techniques for two-way communication.

Commission Self-Assessment

To try to keep a step ahead of these changes, the New York Public Service Commission undertook an extensive self-assessment in the early 1990s. Working with an outside consultant and the State Budget Office, the Commission reviewed all aspects of its mission and its functioning.

Many of the findings from this exercise are applicable to most regulatory agencies. Particular problem areas identified included:

The reactive nature of most regulation. The regulatory agenda and resource allocation tends to be shaped by the cases filed by outside parties rather than by the Commission itself.

The development of specialized fiefdoms within the agency. Historic failures of organization and communication have impeded a melding of staff divisions into effective teams with common priorities.

A continuing sense of overwork. The tyranny of the overflowing in box has been a deterrent to innovative regulation and management improvements.

Discontent with perceived political influences on agency decisions. This concern centered specifically on relationships between the Governor's office and the Commission, but it also reflected a broader concern over ex parte communication.

Tensions between the concept of an independent trial staff and coherent agency management. Any reduction of the historic trial staffs' independence from the commission enhances the ability of management to assure agency priorities are reflected in staff approaches to particular cases. This is a problem for trial staff for obvious reasons, but it may also cause other parties to wonder whether two-way communication is occurring. On the other hand, some parties welcome increased assurance that the trial staff are not out of touch with commission thinking.

Training needs do not take priority. Technical and casework priorities usurp the time and resources needed to develop managerial skills and technical training programs.

As a result of this organizational assessment, extensive changes were made. The agency developed a mission statement, which is included at the end of this chapter. It embarked upon a strategic planning process to develop priorities in light of its mission and to harmonize the schedules among those priorities for both workload assignment and budget preparation. Early examples of priorities include expanding competition in telecommunications, furthering performance based regulation and improving the processes of public involvement.

Some divisions were consolidated to increase coordination, and management techniques to support coordination were developed. Mechanisms to improve communication both horizontally and vertically throughout the agency included better use of agency newsletters, expanded use of e-mail and other electronic information sharing and better accessibility of the Commission to the rest of the agency. New opportunities for training in both management and technical skills were created. Two of the seven commissionerships were eliminated, a small but symbolically significant downsizing. The controversy of this action helped to stress to both staff and utilities that the Commission was serious about change.

Finally, the Commission realized self assessment should not be an occasional, cataclysmic process but should continue as an ongoing function. To do this, the necessary human resource positions and structure were established.

The changes required by this assessment did not come easily, and they are not a panacea. However, a major lesson from this exercise is that no commission can expect to preside credibly over processes that require widespread dislocation and discomfort throughout all aspects of the utility industry without examining its own functioning as well.

Re-Thinking Proceedings

This type of commission reorientation — especially in states with rates well above both marginal costs and national averages — will require approaches not used in traditional rate cases. Proceedings in New York covered a comprehensive set of issues including the structure of the utility industry, the burdens imposed by state and local taxation, environmental impacts, economic development and the nature of effective electric utility competition. A traditional regulatory agency, using traditional rate-case procedures cannot hope to explore and find solutions to the full range of concerns.

The traditional rate case was designed to resolve differences of opinion between the utility and its various classes of customers as to prices and the allocation of costs, with some attention also given to minimizing the environmental impacts. Parties might have disagreed about many issues, but they agreed on the fundamental purpose of the proceeding.

The types of cases regulators face today do not enjoy such underlying agreement. Some participants join the proceeding primarily to gain information about the utility and its customers. Others may participate to influence not the prices utilities charge, but the prices they pay to their suppliers. Some parties take part to delay the process by keeping any conclusion from being reached for a substantial period of time.

Conducting these proceedings require expanded regulatory skills. Traditional accounting functions must be beefed up with skills to assess and promote competitive markets. Traditional legal and adjudicatory skills must blend with skills in mediation, negotiation and facilitation.

Mechanisms for earlier commissioner input are necessary. The process cannot function well if parties labor for months and years to produce a consensus the commission substantially rejects in the end. Within the commission, the traditionally strong line organizations ─ historically prized for their mastery of technical subject matter and their ability to provide advice thereon ─ must give way to more complex matrix management relationships in which the work of employees may be evaluated in part by supervisors who are not in their division at all. This change will alter promotion and resource control decisions as well. Also essential is the ability to work cooperatively with other state agencies in the environmental, economic development, taxation and legislative spheres.

Innovative Approaches For Public Participation

The concept of public involvement is also in a state of flux. The experience with telephone deregulation makes clear the consumer protection function of utility regulation does not cease quickly. Customer expectations are diverse and often inconsistent. Many people still rent their telephones from AT&T even though they could buy them for less than a year's rental. At the other extreme are customers eager to make aggressive and sophisticated choices among energy vendors.

The traditional public hearing, at which a parade of witnesses makes five-minute presentations to the commission or an administrative law judge, does not begin to allow for an effective interaction between the commission and the public. In New York, the Consumer Services Division pioneered a number of innovative, two-way approaches. These included focus groups, roundtables and even the use of closed-circuit televised meetings. The theory behind many of these gatherings was to get the groups concerned about directions in utility regulation talking not just to the commission but to each other to come up with more creative and comprehensive solutions. Whether focussed on a particular rate proceeding or on broader generic topics, these forums provided a much more productive opportunity for the public, the commission and the commission staff to interact.

Through all this, the requirements of procedural due process of law must still be met. Hearings must be made available to any party who seeks to present arguments to the commission in favor of outcomes different from those agreed upon through other processes. However, the scope and contentiousness of such hearings are likely to be substantially reduced if procedures that foster discussions among different viewpoints are instituted.

Finally, the success of performance based regulation also requires the application of these new techniques. The development of performance yardsticks requires not only new regulatory skills but also new types of public input as well, especially in the area of service quality standards. Service quality standards are also important for utility workers. They are the best safeguard against a utility attempting to cut its workforce as it prepares for competition.

The *Washington Post* editorialized not long ago that competition "doesn't mean deregulation. To the contrary, it means more work for the regulators. It's up to them to see that competition is genuine and produces the promised benefits without weakening any part of a system on which the country's life and livelihood depend."[1]

This perspective is the other side of Attorney General Olney's embarrassing words at the beginning of this chapter. The mission of midwifing constructive competition into the electric power industry is as crucial as any ever faced by the regulatory community. It should be approached in that spirit.

[1] *Washington Post* editorial, May 3, 1994.

Encouraging Negotiated Industry Reforms

Rising to the challenge of restructuring the industry is no simple task. It is made difficult by jurisdictional swamps, utility fears of significant financial loss, consumer worries they will pay higher prices now in return for at most a promise of lower prices later and concerns that energy efficiency and the environment will be the first casualty of reform. This chapter describes the steps needed to be taken by state regulators interested in bringing parties together to reform the electric utility industry.

WHY NEGOTIATED SOLUTIONS ARE NEEDED

Jurisdictional Swamps

If one wanted to create an electric utility industry nearly impossible to change, one would create today's industry; an industry with a very wide range of entities (IOUs, Munies, Co-ops, Federal Marketing Authorities, regional holding companies, IPPs) and an even wider dispersion of regulatory jurisdiction (FERC, State PUCs, SEC, REA, Congress, state legislatures and municipalities). The vast number of interests creates a legal framework where no entity has the scope or power to impose a solution on unwilling stakeholders.

Financial Risk

Opening a dialogue on significant industry and regulatory reform, particularly at a time when prices are high relative to perceived market value, means significant financial exposure to utility managers. Under the status quo, utilities are, for the most part, recovering 100 percent of the costs regulators have judged to be prudent. Because there is no hope of recovering more than 100 percent, any new initiative aimed at increasing the level of competition in the industry raises the risk that future cost recovery will set off a new round of losses. This possibility places utilities in a defensive mode where it is in their best interest to avoid initiatives that might risk their current level of cost recovery.

Consumer Worries

For many utilities, the price of electricity is well above the cost of new, gas-fired generation. Consumers have good cause to believe competition offers a route to lower costs. But many consumers, particularly residential and small commercial customers, fear they will bear the costs of creating a more competitive market, and others will reap the benefits. They anticipate some customers (large users) will obtain electricity from new suppliers or extract concessions from utilities based on the threat to buy elsewhere. In either case, the burden of paying for sunk costs will fall to a smaller number of customers.

Environmental Loss

Environmental advocates worry that neither energy efficiency nor renewables will do well in a competitive industry focused primarily on minimizing near-term electricity prices. They also fear the greatest financial gains will come by continuing to run the oldest and most polluting plants.

THE NEED FOR NEGOTIATED SOLUTIONS

Given the jurisdictional quagmire, utility aversion to increased financial risk and consumer and environmentalists fears, it is understandable that progress toward reform has been slow. To make it somewhat easier to proceed, regulators can break down the tasks of what needs to be done. Doing this should set the stage for stakeholders to come to the table and collectively negotiate elements of a restructured industry that serves them all.

Step 1. Realize No One Can Do It Alone

While no stakeholder has the legal authority or political strength to impose his or her position of the future of the industry, virtually every stakeholder possesses the power to stop or substantially delay other parties' proposals. For change to occur, all stakeholders must be satisfied.

Step 2. Understand Stakeholders Have Different Needs And Priorities

At the heart of any negotiation is a knowledge of the interests, concerns and priorities of the stakeholders. The likely positions of key stakeholders described below are not set in stone and will vary from state to state.

The Utility

For most utilities, continued and full recovery of stranded cost is by far their highest priority. But because a restructuring plan is not a cash transaction, how much stranded cost a utility will receive hinges on the details of the plan. To determine how much stranded cost recovery can be expected, a utility will analyze the plan for a number of points, not just those that explicitly deal with the terms of cost recovery. For example,

How long is the cost recovery period? The longer the recovery period, the less likely the utility will actually recover the promised amounts.

How likely is it that stranded cost estimates will change, and who bears the risk of changes in stranded cost estimates during the period? If stranded costs shrink, will utilities have to reduce rates? If they rise, will utilities be made whole?

How politically stable is the restructuring plan? If the plan lacks a broad-based consensus, will it last a decade?

How large is the market risk, and who bears it? Does stranded cost recovery rely on charges that can be bypassed easily by customers, neighboring electricity suppliers or alternative fuel suppliers?

After stranded cost, the utility's next area of interest is its competitive position in the new structure. To what extent will there be vertical integration, and what is the scope and method of continuing regulation. The more integration (vertical and horizontal) and the less regulation, the better the plan will seem to utility managers. (The dream of every capitalist is to be an unregulated monopolist.)

Consumer Advocates

Unlike utilities that have one priority prevailing over all others, traditional consumer advocates have a number of issues which are nearly equal in importance. The highest priority is probably assuring that residential (and possibly small commercial customers) receive lower rates. Consumer advocates, however, are also concerned with a wide range of equity issues as well. They worry competition will cause costs to be shifted to captive consumers, lack meaningful and timely customer choice for low-income consumers, change rate design in a manner that hurts small and low-income users, deteriorate customer service and diminish existing protections for low-income consumers.

Consumer advocates, with experience from telephone deregulation, also fear regulations will be relaxed through deregulation or PBR in advance of actual competition. Finally, many consumer advocates believe consumers prefer increased investment in energy efficiency and renewable resources and thus expect restructuring plans to include provisions that assure continued investments.

Large Consumers
Large users have two priorities, near-term price reduction and increased customer choice, and most rank price reductions well above customer choice.

IPPs and Competitive Generators
Independent Power Producers and other advocates of competitive generation are most interested in open access and efficiently-priced transmission and a level playing field upon which new generation can compete. Some advocates of competitive generation go further and see their interests best served by a package made up of direct access, deregulation of new and existing generation and utility divestiture of generation. The highest priority for most QFS and IPPs with existing contracts is protection of those contracts.

Environmentalists
Environmental advocates focus on three areas. They want continued investment in cost-effective energy efficiency and renewables. Second, they do not want restructuring plans to increase emissions or to allow the life of existing generation, subject to less stringent emission limits than new generation, to be increased. Third, they expect continued investment in R&D for energy efficiency and renewables.

Identifying all key parties and understanding their interests and priorities is a prerequisite for creating an environment conducive to negotiating solutions. The priorities described above leave room for tradeoffs. None of the highest priorities are in direct and irreconcilable conflict. This does not mean there are not difficult tradeoffs to be made. The pressure for near-term rate reductions conflicts with full protection for stranded costs, and stranded benefits and retention of vertical integration conflicts with deregulation of generation.

Step 3. Create An Environment In Which All Parties Have A Reason To Negotiate

The final step is to encourage negotiations by asking the parties to negotiate, providing parties with a policy framework for their negotiations and creating an environment in which all parties have a reason to come to the table.

The first part requires no elaboration.

Giving the parties policy boundaries within which they are free to negotiate and innovate is important. Multiparty agreements typically present regulators with a take-it-or leave it product. The parties will often state that any material modification of the product by the commission nullifies the entire agreement. Given that commissions will want to respect these provisions, opportunities for commission input may be limited to early stages. Parties are less likely to fully commit themselves to negotiations if they believe their endpoint will merely serve as the starting point of a commission proceeding. Negotiations will best proceed if commissions begin the process with an initial proceeding aimed at broadly examining policy issues and options and end it with a clearly articulated policy decision.

Creating an environment in which all parties have a reason to negotiate means knowing what each party currently has, what risks they face, and what they may be willing to tradeoff. Stakeholders will try to work out differences if it appears the product from negotiations will be more desirable than what would happen without negotiations.

Environmental and efficiency advocates will participate because the status quo, with utility reduced commitments for DSM and renewables, is hurting their interests now. The risk that competition will result in a dirtier environment is formidable. Industrial customers and consumer advocates, who want lower prices, clearly have in interest in negotiating and will need little prodding from commissions.

The danger regulators need to avoid is creating an environment in which utilities have no reason to negotiate. Utilities will use two routes to pursue protection of strandable costs recovery. The first is to try to delay resolution of competitive issues. Given that stranded costs are already being fully recovered in rates, a delay reduces financial exposure. While the uncertainty of the status quo is unsettling, resolving competitive issues may be even more unsettling. There is, after all, no chance of doing better than the current 100 percent level of recovery.

The second route of utilities is to convince regulators that stranded cost recovery — in the utilities favor — is the single most important issue to resolve before addressing any other restructuring issue. If utilities succeed in convincing regulators, and commissions respond accordingly, the chances for meaningful reform to occur will fail. To keep utilities interested in participating, regulators should resist the temptation to resolve the restructuring issues of the utilities independently of the issues of all other interests. The more confident the utility is of full recovery of strandable costs, the smaller their incentive will be to enter multiparty negotiations.

COMING TO THE TABLE IN RHODE ISLAND AND MASSACHUSETTS

Many states have been encouraging negotiated solutions to restructuring issues. The Massachusetts Department of Public Utilities (MDPU) initiated a Notice of Inquiry proceeding seeking comments on electric industry restructuring in February 1995. In the summer of 1995, 20 stakeholders in Massachusetts and Rhode Island did come to the table and negotiate a set of interdependent principles to guide electric industry restructuring. These principles are summarized below and included in their entirety in the appendix at the end of this chapter.

The principles stipulate that there should be

1. Reliability and safety, with customers having the opportunity to choose and pay for different levels of reliability.
2. Fairness and consistency for all sellers and buyers.
3. Benefits to all customer classes in a manner that does not unfairly shift costs.
4. Enforceability of contractual rights and obligations.
5. Recovery of stranded costs arising from past decisions, recognizing though that utilities have an obligation to try to mitigate such costs. A non-bypassable, non-discriminatory mechanism for recovery from customers within the franchise territory should be proposed.
6. Provision of near-term rate relief for all customers. Opportunities for greater near-term rate relief should be available to customers who assume greater market risk.
7. Unbundling of services to avoid anti-competitive behavior. Generation must be at least functionally separated from transmission and distribution. Transmission companies should provide open access for all competitors.
8. Choice at the retail level to allow customer-specific needs to be met. Access to utility wires for the purpose of purchasing electricity from alternate suppliers should be made available as soon as practicable. Non-bypassable, non-discriminatory charges should be established for recovery of stranded costs and provision of potentially strandable benefits. Distribution utilities should maintain an obligation to connect all franchise customers.
9. Spot markets to establish market clearing prices.
10. Streamlining administrative processes to make regulation more efficient and more reliant on ordinary business transactions. Market-driven choice should replace traditional planning mechanisms as the means to supply resource needs.
11. Regionalism through creation of a regional transmission group that replaces NEPOOL.
12. Environmental improvement. Emissions from fossil-fuel plants that currently do not meet emissions standards for new units should be reduced through retirements or replacements or through a requirement that they meet the emission performance standard of new units.
13. Reduce market barriers for cost-effective DSM and energy efficiency. Utilities should target opportunities not captured by providers of non-utility energy efficiency services. Costs associated with DSM programs should be included in a non-bypassable, non-discriminatory charge.
14. Fuel and technology diversity, including clean and renewable energy sources, to manage risks and reduce environmental impacts. Transition support may be required for some renewable and low-emissions technologies.
15. Provision of universal service. Support of programs enabling customers with fixed or low incomes to afford electricity should be funded through a non-bypassable, non-discriminatory charge.

In August 1995, the MDPU issued its own Statement of Principles that drew from and is consistent with the principles filed by the parties. In addressing its goal of insuring the transition orderly, expeditious, with a minimum of` customer confusion, the MDPU stated:

"A smooth transition process would best be achieved through a negotiation process that includes all affected parties including representatives of residential, commercial and industrial customers, utilities, independent power producers, power marketers, public interest and environmental organizations, and government agencies." (M.D.P.U. #95-30, August 16, 1995 Order, at page 45)

The next step involves detailed negotiations leading to specific utility filings to be made early in 1996.

Similar negotiated processes fostered by PUCs are now taking place in many states.

CONCLUSION

The task of restructuring the electric utility industry is enormous. The only way progress will be made is by recognizing that decisions do not lie with a single entity but with many interests, all of whom have something to gained by entering into discussions about the industry's future. Regulators can initiate the process of defining common principles by working through with all stakeholders what each wants and what each is willing to tradeoff. The next step — applying these principles to a new utility structure — will demand a combination of creative thinking, serious analysis and problem solving.

INTERDEPENDENT PRINCIPLES

OF

THE MASSACHUSETTS ELECTRIC INDUSTRY RESTRUCTURING ROUNDTABLE

Preamble

On February 10, 1995, the Department of Public Utilities ("Department") issued a Notice of Inquiry and Order Seeking Comments on Electric Industry Restructuring (D.P.U. 95-30). The Department initiated the investigation to determine how a restructuring of the electric industry could increase competition, promote efficiencies and benefit consumers. The investigation has attracted a wide audience of stakeholders; more than fifty parties filed Initial Comments on march 31, 1995, participated in hearings before the Department, and filed Reply comments on May 26, 1995.

From the outset of the investigation, an array of complex issues requiring difficult trade-offs and compromises surfaced. For seven weeks commencing on June 8, 1995, approximately twenty parties engaged in such a process facilitated by a mediator qualified pursuant to M.G.L. c. 233, §23C. The participants represented a broad spectrum of buyers and sellers of electricity plus several agencies of the Commonwealth. The result is the set of Massachusetts Interdependent Principles ("Principles") below.

The Principles reflect intricate and significant compromises made by the parties in an effort to reach a basis upon which meaningful, utility-specific negotiations can begin. Contingent upon the Department acknowledging that these Principles are reasonably consistent with the Department's own principles, and consistent with the Department's procedural schedule, it is the parties' intention to proceed immediately with the negotiation of individual utility restructuring plans, consistent with these Principles. The parties agree to exchange the information necessary for the negotiation process to proceed expeditiously. These plans are expected to define the commitments which specifically implement these Principles in light of the particular circumstances of each utility.

Each party's endorsement of these Principles is only as a package to be used for the sole purpose of producing a framework for future negotiations, and all parties agree that their endorsement of these Principles may not be referenced, used, or otherwise relied upon for any other purpose. If the Department rejects these as the framework for negotiations or proposes modifications which fail to be expressly accepted by the parties, they shall be deemed withdrawn. While the compromises reflected here may not be precisely those which the Department would have otherwise embraced to guide the negotiation of individual utility restructuring plans, the parties request that the Department permit the parties to proceed within this framework.

The effort made by the parties to these Principles demonstrates their commitment to moving Massachusetts forward as soon as possible to achieve the benefits from a fully competitive, restructured industry. The parties respectfully submit these Interdependent Principles for the Department's review and consideration.

Massachusetts Interdependent Principles

1. **Reliability**. Reliable and safe electric service should be maintained. Customers should have the option to specific and pay for different levels of firmness of energy supply and power quality to reflect their individual preferences, and should be held accountable for these specifications.

2. **Fairness and consistency**. The rules going forward should be fair and consistent for all sellers and purchasers.

3. **Benefits to all customer classes**. All customers should have an equitable opportunity to share in the benefits of increased competition and to choose among suppliers. Costs must not be shifted unfairly among customers, especially to residential or small business-customers.

4. **Enforceability of Contractual Rights and Obligations**. The rights and obligations embodied in contractual arrangements are and will be an indispensable element of the competitive power market. Contractual arrangements for the purchase and sale of power are and shall be enforceable by their terms.

5. **Recovery of stranded costs**. Utilities should have a reasonable opportunity to recover net, nonmitigatable, strandable costs arising from past decisions. Utilities have an obligation to take

all reasonable measures to mitigate such costs. During the next phase of the negotiations, each utility's restructuring plan should identify and quantify such above market utility costs and a mechanism for recovery in a non-bypassable, non-discriminatory, appropriately structured charge. The amount of above-market costs should be determined on a net basis that takes into account both above-market and below-market resources. Charges to recover stranded costs should apply with respect to customers within a utility's retail franchise territory only. The charges should not apply to wheeling-through transactions.

6. **Provision of near-term rate relief**. The primary objective of electric industry restructuring is to create competitive markets that are expected over time to produce prices lower for all customers than would have been paid under the current system. In addition in the near term, distribution utilities should develop mechanisms designed to produce rates for all customers meaningfully lower than they would have been under the current system of rate regulation. Utilities should also make available a reasonable opportunity for greater near-term rate relief for customers that choose to assume greater market risk.

7. **Unbundling of services**. The existing vertically integrated structure of the industry should change. Generation should be subject to full and fair competition and must be at least functionally separated from transmission and distribution so as to avoid the potential to favor affiliates when offering and pricing their services. Companies providing transmission should file comparable service transmission tariffs at FERC that provide open access for all competitors. Restructuring plans should be designed to avoid anti-competitive behavior. Companies providing both transmission and distribution should be reviewed in order to determine whether other mechanisms are necessary to avoid the potential to favor affiliates when offering and pricing their services.

8. **Choice at the retail level**. Retail customer choice can provide benefits beyond those provided by a competitive wholesale market and is therefore an immediate priority. Individual customers (or groups of customers) differ in the quality of electric service they require and in the risks they are willing to take. By purchasing themselves, they can commit to an electricity supply based on short- or long-term projections of their own needs, rather than on the necessarily long-term projections of the utility and its regulators for the system as a whole. Small customers'

access to competitive supply options is expected to be accomplished, among other ways, through aggregators, which may include private firms, municipalities, cooperatives and other similar entities. Load management activities such as reducing usage during expensive peak periods can be of direct benefit. Access to the utilities' wires for the purpose of purchasing electricity from alternate suppliers should be made available to all customers as soon as practicable, subject to the resolution of engineering and regulatory prerequisites, including the establishment of charges for recovery of stranded costs and potentially strandable benefits. In the interim, some forms of efficient direct access may provide a useful means of introducing customer choice at the retail level. Distribution utilities should continue to have their current obligation to connect all customers in their franchise area to the distribution system.

9. **Spot market**. A spot market for electricity should be developed. The spot market should enable sellers to sell and purchasers to purchase at market clearing prices.

10. **Streamlining administrative processes**. Regulators should streamline administrative processes to make regulation more efficient, and so as not to delay competitors' ability to adapt to changes in the market, consistent with effective protections of consumer and environmental interests. The market framework for competitive electric services should, to the extent possible, maximize reliance on ordinary business transactions and minimize reliance on administrative process. Traditional planning mechanisms ultimately should be replaced by market-driven choice as the means of supplying resource needs.

11. **Regionalism**. NEPOOL should be reformed and a regional transmission group created to enhance competition and to complement and support industry restructuring on a regional basis.

12. **Environmental improvement**. Environmental performance is integral to electric industry restructuring. As generation becomes deregulated, environmental impacts should be reduced. These impacts include the emissions profile of each competitor's portfolio of fossil-fueled power plants that currently do not meet today's emissions performance standards for new units. These impacts should be reduced on an overall basis through retirements, replacements, controls, or offsets toward, at a minimum, the emissions performance standards for new units in effect as of the date of this agreement. For a utility's portfolio, these reductions would be set forth in the

utility's restructuring plan. In addition, an objective during restructuring would be to find new innovative means to meet long-term environmental goals.

13. **<u>Cost-effective DSM</u>**. Restructuring should be designed to reduce market barriers to energy efficiency and not to reduce cost-effective customer conservation. During the transition to full direct access, utility energy efficiency investments will continue to play a valuable role in reducing market barriers, reducing customer costs, and mitigating power system environmental impacts. Programs that are cost effective and approved by regulators should be available to all customers using the distribution system. Where market barriers to energy efficiency remain after the transition, programs that are cost effective and approved by regulators should be available to customers using the distribution system. Efficiency programs before and after the transition should not conflict with an increase in non-utility energy efficiency services, and should target cost- effective energy efficiency opportunities that would not be captured without utility investment. The costs associated with these DSM programs should be included in a non-bypassable, non-discriminatory, appropriately structured charge.

14. **<u>Fuel and technology diversity</u>**. Clean and renewable energy sources can play a valuable role in providing fuel diversity, managing risks and reducing environmental impacts. However, some renewable and low emissions technologies may need transitional support to achieve commercialization and ultimately compete in wholesale and direct access power markets. Where this is true, the costs of such support which are approved by regulators should be included in a non-bypassable, non-discriminatory, appropriately structured charge.

15. **<u>Provision of universal service</u>**. Electricity is an essential product which must be available to all customers. No household should be forced to take a less firm supply than they have today because of lack of income. Special rates, payment programs, energy efficiency services provided through optimal use of publicly-funded low-income weatherization providers, protections regarding customer service and shut-offs, and other tools to enable customers with fixed or low income to manage and afford essential electricity requirements, should be included in any restructuring proposal and funded through a non-bypassable, non-discriminatory, appropriately structured charge. Further development of such rates, programs and protections to address the goals of universal service should continue under restructuring.

16. **Incentive regulation**. Incentive ratemaking can be an important technique and should be considered for regulating all of the remaining monopoly segments of the industry.

17. **Capital attraction**. Any new industry structure should create the opportunity for financially sound and profitable entities that can attract capital at a reasonable cost.

18. **Reliance on voluntary agreement**. Consensus and settlements are more likely than litigation to move restructuring forward, given numerous potential interstate, state-federal, state-utility, and inter-party substantive and jurisdictional conflicts.

Dated: July 17, 1995

Technological Change: What Does it Mean for the Future and for Regulation?

The electric utility industry and its associated regulatory system developed from a structure where power was produced at large (oil, coal and nuclear) power plants, high voltage transmission systems interconnected sources of generation and transmitted large amounts of power, and distribution systems distributed electricity to customers. From the 1900s to the 1960s, the industry thrived on capturing economies of scale and vertically integrating the business into a seamless operation, from the customer's point of view. During these years, each new plant was larger and more efficient than the preceding plant. Prior to World War II, the thermal efficiency (the percent of a fuel's energy content transferred to electricity) of these central station plants was 21.8 percent. Advances in metallurgical knowledge together with access to new materials developed for aircraft and artillery during World War II, provided the tools for thermal efficiency to rise to 32.9 percent by 1965.

The upside of these economies of scale was the continued reduction in the real per kWh cost of supplying energy to customers. The downside of larger and larger plants was the difficulty of efficiently managing large, on-site construction programs. New capacity came into the system in sizes that, by necessity, leapt considerably ahead of load growth and thus caused “lumpiness.”

Starting in the mid-1960s, this pattern of building larger plants to capture economies of scale began to fall apart. Metallurgical weakness at high temperatures and pressures, unreliability of large plants, long construction periods and environmental concerns and a flattening of thermal efficiencies eventually exhausted the economies of scale for large-scale generation. By 1970, the efficiency of central thermal power stations for electricity production had peaked.

Technological change will continue to steer the electric utility industry as it has in other industries. Indeed the primary driver in today's electric industry — the high cost of electricity from existing generation relative to new generation — is a direct consequence of technological advances in generating electricity from gas turbines, as well as technological advances in gas exploration. These forces have combined to bring the cost of new generation down from 6 to 8¢/kWh in the late 1980s and to between 3 and 4¢/kWh today.

Understanding what is happening to technology is important to regulators as they consider how to reform existing industry and regulation structure. Regulators need to avoid the temptation to choose an industry model that fits well with current technology (or worse yet, past technologies) but poorly with new technologies. Regulation need to be less concerned with the future of the past (how to deal with historical legacies and projections of existing technologies) than the future of the future (how to prepare for and encourage the development of the next generation of technologies).

THE EXPANDED ROLE OF MANUFACTURED TECHNOLOGY

Today's emerging technologies include demand- and supply-side options that share two characteristics. First, they tend to be manufactured in factories rather than constructed on site. This means they are capable of capturing quite different efficiencies than large, central station power plants. Second, new technologies, especially gas turbine, fuel cell, wind and solar, are at the beginning of their technological development curve, not the end.

These characteristics mean:

- With technologies available in modular sizes ranging from under 1 MW to 250 MW, they are capable of matching demand more precisely.
- Lead times for plants to come on line are from one to two years rather than four to ten years.
- Thermal efficiency is much higher than conventional steam generation.
- Air emissions are low.
- Small size and low emission rates mean plants can be located much closer to the ultimate customer. This distributive function is extremely important.

These features of manufactured technologies make them extremely important in a more competitive electric industry and have the potential of providing much richer options for the end-use customer.

WHAT ARE THE TECHNOLOGIES?

Gas Turbine

Using technology developed for military and civilian aircraft use, the gas turbine has evolved from a low efficiency, high maintenance peaking option to a low-cost, reliable, small and modular technology available for baseload power and peaking generation. Aeroderivative combined and simple cycle turbine power plants are rapidly becoming the choice for new generation and accordingly have captured a major share of the emerging independent power market. They require ten to 30 percent less capital and can be installed relatively quickly. Continuous increases in firing temperature means some commercial applications already have 55-60 percent efficiency (Lower Heating Value), and the top of the technological curve has not yet been reached. Advanced gas turbine technologies, when equipped with an appropriate bottoming cycle, could achieve efficiencies in excess of 60 percent (Lower Heating Value). The introduction of military maintenance procedures and use of rapid change out of components and engine sections have dramatically reduced unscheduled downtime and maintenance costs. Demonstration and evaluation of even more efficient units are planned by the end of the 1990s.

These turbines are also important for what they might mean for the use of coal and biomass. Biomass and coal have fueled power plants for a long time. When used in their solid forms in steam boilers, however, thermal efficiency, especially for biomass, is relatively low, and the cost for a small boiler system is high. When gasified, these fuels can be used in combination with turbine technologies to increase thermal conversion efficiency and hence decrease costs substantially ─ even for smaller-sized units. Turbines are especially attractive for biomass because the gasification and related gas cleanup process is much simpler and cheaper than for coal. Further, the availability of smaller, inexpensive units allows plants to be placed closer to the fuel source, thus increasing the efficiency and lowering the cost of wood transport.

The first prototype, a six megawatt biomass gasification combined cycle gas turbine, is in operation in Värnamo, Sweden. With the support of the Global Environment Facility, a large 25 MW plant is being considered for Brazil's northeast state of Bahia.

Smaller turbine-based systems in the 200-250 kW range have been developed for the military for tank and vehicle applications. Combining these turbines with generators will result in a small and fairly efficient generator system. These mobile turbine generators are being tested with military deployment fuel and natural gas.

Fuel Cells

Fuel cells may be the most promising of the new technologies for the not too distant future. Fuel cell power plants are under development worldwide because of their potential to produce relatively small quantities ─ tens of kilowatts to tens of megawatts ─ of very high quality electricity at very high efficiencies, with essentially no noise or emissions other than carbon dioxide and water. Customer-based market niches are developing for commercial and industrial applications where the still-high capital cost of fuel cells is compensated by their value. The challenge currently facing the fuel cell industry is typical of the dilemma faced by developers of all products for the dispersed generation market; that is the need to aggregate sufficient market demand to bring the average product cost down to a level that encourages development of even more markets and elicit an understanding of the value of dispersed systems.

Just as the turbine technology revolution came from investment and R&D by the aircraft industry, fuel cells may enter the utility sector through extensive R&D in the automotive industry. The auto industry is investing hundreds of millions of dollars to develop the hybrid electric vehicle (EV). One of the most promising technologies in this effort uses a 20 to 25 kW permeable exchange membrane (PEM) fuel cell. Already, the technology is proven, the materials are neither exotic nor hazardous, and prototypes are in use today in buses in the United States and Canada. A report by Allison Motors (a subsidiary of GM) estimated an annual production of one million electric vehicles per year would result in a fuel cell cost of approximately $50/kW compared to $5000/kW for the hand-built units in place today. On the path from today's $5000/kW to the $50/kW projected by Allison Motors, lies $500 to 1000/kW, the cost at which a PEM fuel cell, sized for residential or commercial application, could produce electricity at the same cost as larger turbines.

Other Resource Technologies

Manufactured technologies are not limited to supply-side resources. The list below describes a number of technologies. Some are already fairly widely used, others are in prototype stages, but all are likely to become increasingly important. The timing of their introduction and integration into the nation's electric system will vary, driven by the speed of commercial development and cost.

Storage technology, at this time, is largely limited to batteries. Still in a prototype stage but likely to emerge as viable and important are composite or carbon fiber flywheel storage systems. Their first use may be for voltage regulation, but a role for storage should follow. Fly wheel systems will be able to be designed and built to a wide range of storage specifications. Size requirements for a typical reasonably efficient household are in the two kWh range.

Photovoltaics (PV) will be playing an increasingly large role, particularly in areas where transmission and distribution are difficult. PVs can be included in energy efficient homes and/or replace other home functions, such as integrating PVs into roof shingles or facades.

Small wind turbines are already on the market and will become even more prevalent. They are deployed worldwide and provide an effective means of providing electrical services in many developing countries and/or remote locations.

Energy efficiency technologies include almost anything that makes electrical usage more efficient. Motors, lighting, windows and insulation all will become more efficient. Better passive solar designs will become common.

Energy management systems which efficiently integrate all energy use in large, commercial buildings or in manufacturing processes are getting cheaper, particularly as the price of microprocessors fall.

Information and control technologies are also evolving rapidly. Low-cost and powerful microchips are being incorporated in new appliances. Computers have the capability of controlling appliances and being in touch with other devices in the home or business, including a new generation of smart meters capable of communicating with remote generation and transmission and distribution systems.

AC/DC Conversions

The transmission system offers some fertile ground for innovation. Technologies to convert from AC to DC and DC to AC will be very valuable. Because DC wires can connect to the AC grid only through relatively expensive AC/DC conversion facilities, DC wires are only used to move large amounts of power over great distances.

If, however, new technology brings the cost of conversion down, many more transmission systems would likely move into the DC realm. Doing this could almost double the capacity of the current rights of way. DC systems are also free from the problems of loop flow that face AC transmission. (Capacity inefficiently used for loop flow will be a financial liability for owners of transmission lines.) Adding branching capability would further increase the flexibility and value of DC.

RESTRUCTURING FOR THE FUTURE OF THE FUTURE

Continued development of these technologies is highly desirable. Development promises to lower costs, increase customer options and choice and improve the environment due to substantially lower environmental impacts. At the same time, the pace and extent of the development of these technologies will be affected by restructuring options. This raises several important issues for regulators.

1. What services are (or will remain) monopoly services?

2. How will choices regarding industry structure encourage or impede the development and deployment of these technologies?

3. What regulatory policy should be pursued during the transition period?

What Industry Structure?

The dilemma these technologies present is they challenge the tendency to view the electric utility as having three separate and distinct parts — generation, transmission and distribution. Small, dispersed generation or energy efficiency easily spans all three. A well-located fuel cell, particularly one capable of two-way communication with information from the other areas, can provide generation and impact transmission and distribution services. Thus, if distribution utilities are prohibited from owning generation, will they deploy dispersed generation as a distribution or transmission substitute? How will generation that has 3¢/kWh of generation value, 2¢/kWh of distribution value and 1¢/kWh of transmission value be evaluated? Will the solution require geographic unbundling of prices so a consumer in a remote area can select a dispersed generation option? Will geographic unbundling be practical and publicly acceptable? Will these technologies provide the means to allow customers to bundle services more tailored to their needs and values? The answers to these questions are far from clear.

Experience in the telephone industry shows that competition allows for more rapid development and deployment of technologies. In the telephone industry regulators developed new concepts such as Standard Network Interface, co-location and open network architecture to limit the scope of the remaining monopoly and thus allow competition to penetrate as deeply into the industry as possible. Are there new regulatory concepts that could be used in the electric industry to accomplish the same ends?

The Transition

Reform of the electric utility industry will be a long and difficult process. The current transition period, which is likely to last a decade or more, puts all the players in the worst of two worlds. The transition to a yet uncertain future, placing existing utilities under increased financial pressure and risk, has begun. One type of utility response has been to reduce, and in some cases, eliminate R&D and commercialization of the technologies discussed in this paper. Yet with a fully competitive market still far enough into the future, entrepreneurs are neither ready to take up the slack and make all the R&D investments these technologies need nor do they have clear access to markets or customers.

Thus while it is seductive to imagine a future in which generation and information and control technologies transform the industry, with little or no role for regulation or public policy, there are at least two reasons why this thinking is flawed.

First, many of the technologies described are not yet commercialized and those that are will take decades to make substantial inroads into markets. Second, and more important, the pace at which these technologies are developed and deployed will be greatly influenced by policy decisions regulators make now and throughout the transition period.

This is especially true for distribution applications because there is not yet an adequate technical understanding of how the distribution system will handle widespread (beyond 15 or 20 percent penetration) dispersed generation. How will engineering of the distribution system have to change? What new information and control systems will be needed?

During the transition, all or most of the current industry will be regulated. It may be traditional cost-of-service regulation, PBR or some other form of regulation. Whatever system is in place, it will create a set of incentives that encourages utilities to do some things and avoid others. The design of these transition regulatory mechanisms should include provisions to assure continued R&D demonstration and use in areas expected to yield consumer benefits and offer choices to customers.

• Modular turbine generation systems will become less expensive as turbines in the 50, 100 and 150 MW range continue to come down in price, causing the early retirement of existing coal-fired generating capacity.

• R&D in the auto industry will reduce costs of stationary PEM fuel cells to the point where residential electric (and hot water) is provided by natural gas companies.

• Cost of small modular storage is already declining, and cost-effective, small modular storage will be available within the next decade. The availability of electrical storage at the household level will revolutionize the way customers interact with their utility company. Time-of-use will be replaced by time-of-buy. This will give customers a great deal more latitude in how they manage their energy use and will make investments in on-site, PV modules and small wind generators much more feasible.

• Advanced power conditions, smart energy management and the cost of information storage and processing will decline. New customer interface systems will provide much more detailed information. Cable TV, telephone, cellular and satellite-based companies will enter the metering, billing and control services markets .

• Design of new residences of all types — pre-fabbed, modular, apartments, large and small houses — will be increasingly energy efficient and smart.

• Production of energy efficiency products — appliances, electric motors, variable speed motors, high compact fluorescent lights — will continue to increase, and costs will come down. Every appliance will have a microprocessor capable of communicating with power supply controllers.

• Electric vehicles, long viewed as the electric utilities' best friend, will instead be its greatest competitor. Rather than relying on a battery-based technology, charged by electric utilities, they will do the opposite. EVs will be fueled by on-board, PEM fuel cells and supplemented by flywheel storage. Instead of plugging the car into the house for a charge, commuters returning home will connect their cars to their homes for their source of power. During the working day, a EV may help power the customer's business premises, a local grocery store, etc. Taken together, the American fleet of cars and trucks are the equivalent of 4,875 GW or over six times the country's needs, and they are generally idle 90 percent of the time! Unlike internal combustion engines designed for a very limited life or duty cycle, a PEM has no moving parts and can easily be operated at base load for long periods of time.