# RENEWABLE ENERGY:

# BARRIERS AND OPPORTUNITIES, WALLS AND BRIDGES

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# RENEWABLE ENERGY: BARRIERS AND OPPORTUNITIES

## OVERVIEW

Renewable energy resources, those based on solar energy, wind, geothermal, biomass, and other non-depletable fuels, can meet electric energy needs in a cost-effective and environmentally acceptable manner. Renewable resources have made enormous progress in the last fifteen years. Much of this progress is due to the efforts of a few key states where regulators, utilities, and other policy makers stripped away impediments to the use of renewable resources.

This report builds upon this progress and examines the remaining policy and practical barriers to the increased use of renewable resources for the generation of electricity.[(1)] In addition to suggesting ways of removing identified barriers, this report provides a number of new policy initiatives designed to accelerate the transition to renewable energy sources.

Renewable resources can take a variety of forms. Electricity from these resources can be interconnected with the electric grid or can stand alone, independent of the grid. They can take the form of large, centralized facilities like conventional fossil fuel plants or they can be small, decentralized, and dispersed throughout the utility's system. The renewable resource can be owned and operated by a regulated electric utility or by a non-utility generator (NUG).

Identifying and removing existing impediments to renewables is important because many renewable resources such as hydro-electric, geothermal, and wind are already cost effective in many locations. Artificial barriers which prevent greater reliance on such cost-effective resources produce a burden that customers -- and the nation -- can do without.

Even renewable technologies that are not yet cost effective in wide-scale applications, such as photovoltaics (PV) may be cost effective in "niche" applications. Continued R&D and modest utility investments in demonstration-sized facilities promise to reduce costs. New initiatives that support the sustained orderly development of these technologies are needed.[(2)]

Renewables currently provide about eight percent of the nation's electricity, mostly by means of relatively large hydro-electric facilities. According to the 1991 U.S. Department of Energy's National Energy Strategy, renewable resources have the potential to provide as much as eighteen percent of the total U.S. electricity production by the year 2030. In contrast, an alternative national energy strategy prepared by a coalition of energy and environmental groups projects that renewables could meet 35 to 53 percent of electricity needs by 2030 (Union of Concerned Scientists, 1991).[(3)]

Regardless of the relative accuracy of these two projections, renewable resources clearly can and will play an increasingly important role in the production of electricity. However, the current institutional and regulatory environment is far from conducive to the accelerated development of renewable resources. Despite the impetus provided by the Public Utility Regulatory Policy Act (PURPA) which greatly encouraged the development of renewables, and despite the impressive success of a few states, substantial and persistent obstacles remain. As is often the case, problems reside not at the broad policy level, where expressed support for renewables is strong, but in the details of 1) the utility planning methods and 2) the resource acquisition relationships between renewable resource developers, electric utilities, and regulatory institutions. It is these details which largely determine the economic viability of renewable resources.

The first section of this report focuses on the key obstacles to renewable development, along with suggestions on how they might be overcome. In large part, these specific barriers can be addressed by means of serious state commitments to both least-cost planning and the implementation of PURPA. In short, the prescription for renewables is: adopt least-cost planning and do it right!

**The prescription for renewables is: adopt least-cost planning and do it right!**

These steps involve no new initiatives but are especially important because they relate to the entire spectrum of utility resource planning and resource acquisition, not only renewable resources. If the appropriate planning tools and resource acquisition practices are ignored or misapplied, utility investment in energy efficiency and new capacity will all be misdirected.

The second section of this report offers several new initiatives to hasten the development of renewable resources. The initiatives are separate but complementary, and the proposals can be pursued individually or in any combination. The initiatives are listed in general order of importance.

The initiatives are described independently of the barriers because they are not aimed at correcting or removing specific barriers directly. Rather, these initiatives seek to accelerate renewable development whether or not the barriers previously identified are successfully removed.

By increasing the use of renewables through the use of these initiatives, regulators, utilities, and the public will more quickly learn of and benefit from the valuable contribution renewables can make. With this experience and education, attention can turn to removing other barriers.

## SUMMARY OF BARRIERS

**Barrier #1: Information -- The lack of up-to-date and reliable information on the cost and performance of renewable resources means many renewables are completely ignored in the planning process.**

Unfortunately, the early experience with wind, solar, and other renewable technologies was not good. Costs were high, reliability was poor, and not all developers were reputable. Even more unfortunate, however, is that this early experience continues to color the impressions of many utility engineers, planners, and those in the utility regulatory community.

Significant advances in the cost and performance of renewable technologies have been made. Reliable information on all alternatives, is essential for a planning process to correctly select least costly resources. Therefore, a coordinated and constantly updated source of information on renewable technologies is needed. Such information should be made available in a variety of forms to assure that it is useful to executive and policy level people as well as to detailed system planners.

**Barrier #2: Planning -- Commonly used resource planning and avoided cost methods understate the value of renewable resources.**

Regulators must adopt and properly implement least-cost planning so that existing cost-effective renewables are not overlooked. At a minimum this means:

- Planning and avoided cost methods must be capable of identifying the value of the operating and risk characteristics of specific renewable resources;

- Environmental benefits of renewable resources should be considered in resource planning and acquisition processes;

- Cost savings associated with the transmission, distribution, reliability, and location of dispersed renewable resources should be identified; and

- Cost-effective applications for remote, stand-alone renewable resource alternatives should be identified.

Too often the methods being used to define and measure utility avoided costs are not up to the task. The result is that cost-effective renewable resources are ignored.

**Jargon is sometimes the culprit.**

Terms such as "non-dispatchability," "intermittent," and "excess capacity" may seem useful in describing different types of resources or utility system conditions, but these terms often obscure the economic value of renewable resources. In fact, the economic value of resources with these characteristics can be measured with substantial accuracy.

Similarly, the simple sounding concept of "need" or "lack of need" for power often acts as a serious barrier to renewables. Need for power is primarily an economic concept defined by the least-cost planning process, not by a simple comparison of demand and supply. In sum, new resources are "needed" whenever they cost less than the utility's avoided cost.

Finally, there are new refinements to the least-cost planning and avoided cost processes which might improve our ability to distinguish between the value of different resources. Chief among these is the use of new methods to more accurately reflect the relative risk of different resource options.

**New resources are "needed" whenever they cost less than the utility's avoided cost.**

To hasten state adoption of least-cost planning, we should expand upon the technical assistance programs that are beginning to be developed on a national level to offer state regulators the technical and expert resources to assess current practices and revise these practices where needed to properly implement least-cost planning in general and incorporate renewable resources in particular.

## Barrier #3: Acquisition -- Resource acquisition practices are biased against renewables.

The next step after information and planning is resource acquisition which in many cases means contracting for power from non-utility sources.

Pricing terms are key. Widely accepted planning and utility investment principles focus on the net present value of total costs, without undue regard to distinctions between capital costs and operating costs. If these same rules applied to all power purchase practices there would be no bias against the relatively high capital costs of renewables. In reality, however, the resource purchase rules often differ from utility investment rules in ways that disadvantage capital-intensive projects such as most renewables.

Specific contract terms and conditions are also important. For example, requiring unreasonably high levels of insurance to guarantee that NUGs meet long-term contractual requirements will hinder renewables. Needlessly stringent contractual security provisions may do little more than bias resource selection.

Limitations on contract duration, contract reopening terms, and provisions specifying the conditions under which utilities may suspend power purchases are also contract terms which can bias resource selection against renewables.

## Barrier #4: Process -- The time, expense and credibility of the regulatory process can be a special problem for renewable resources.

Resource acquisition rules that demand substantial time and money in the acquisition process itself can be a special problem for renewable resources. The state regulatory process should be designed to minimize the regulatory time and expense that must be borne by developers of renewable resources. Standard contract terms which take into account the capital-intensive nature and particular needs of renewable resource development can also minimize transaction costs and convey state and utility policies to developers and the financial community.

## SUMMARY OF NEW INITIATIVES

This section of the report goes beyond correcting identified barriers to the greater use of already cost-effective renewables by suggesting a number of practical policy initiatives for hastening their development. In some cases, the initiatives focus on renewables which are not yet fully competitive or which may become competitive in limited situations or applications. In other cases, the initiatives look at alternative ways of addressing difficult, time consuming, and controversial issues.

### Initiative #1: Green Pricing -- Green pricing options will give the consumer the choice to use renewable resources.

The marketplace abounds with environmentally benign or "green" products. Products made with recycled materials or manufactured without harmful chemicals appeal to consumers who are willing to pay higher prices for these more costly but environmentally friendly products.

Likewise, public opinion polls and market research consistently show that many consumers are willing to pay higher electricity bills in return for greater reliance on cleaner and safer generating technologies.

Under "green pricing" consumers will be offered an optional electricity product, namely, energy produced using a renewable-based rather than a fossil-based mix. The rate for the green product will be slightly higher than the ordinary rate to cover the incremental cost of additional renewable resources over and above the level of renewables that is already cost effective.

This optional rate would be marketed to all customer classes. Special "green bills," emblems, or decals for commercial and industrial customers, and joint utility advertising will be used to promote the rates. This and other innovative pricing policies will allow consumers to have a direct role in resource acquisitions made on their behalf.

### Initiative #2: Utility Incentives -- Utility incentives to acquire renewables will focus utility management's attention on cost-effective renewable resources.

It is now widely accepted that in the past, the lack of financial incentives has handicapped utility pursuit of energy efficiency. In recent years, however, the adoption of relatively small utility incentives has had a profound effect, greatly increasing utility interest and investment in energy efficiency.

Similarly, the current rate-setting process provides no incentive for a utility to acquire renewable resources. Modest and carefully designed incentive mechanisms encouraging utilities to acquire cost-effective renewable resources may produce much larger returns than the traditional approach of providing the developers of renewable resources with incentives or subsidies.

**Initiative #3: Green RFPs -- Carefully construct requests for proposals and other utility programs to help renewable developers reduce transaction costs and match promising renewable resources with utility needs.**

Competitive bidding for new supply-side resources has become commonplace. Unfortunately, typical competitive bidding documents are not designed to incorporate most renewable resources. Green RFPs, or competitive bidding solicitations limited to renewable resources, can help overcome existing shortcomings and increase interest from developers of renewable resources.

A targeted program in which utilities attract and assist developers of renewable resources can also be of substantial help. Utilities know the resources within their service territories as well as the local and state licensing processes. Providing this information to developers of renewable resources can be a powerful tool in attracting desirable renewable projects.

**Initiative #4: Safe Harbor -- State regulators should develop safe harbors which reduce utility uncertainty with respect to renewable resources.**

Many renewables would benefit from further research, development, and demonstration by utilities. Utilities, however, are risk averse and often avoid pursuing renewable technologies, not so much because of the technological risks of new renewables but because of the regulatory risk and uncertainty about the recovery of costs associated with innovative pilot or demonstration programs. Commission rules that provide utilities with a "safe harbor" for renewable energy demonstration projects can easily overcome this barrier.

## Initiative #5 Stand-alone Service -- Adopt rules that encourage the use of cost-effective renewable-based customer stand-alone service.

Regulators and utilities should adopt service and pricing options for non-connected, off-grid customers to assure that cost-effective renewable resource alternatives for these customers are fully considered.

As the cost of modular renewable power technologies continues to decline, the extension of utility distribution lines to new off-grid loads warrants more careful analysis. Likewise, the small, dispersed renewables might be a cost-effective alternative to the replacement or upgrading of existing lines to small, remote, or hard-to-serve customers.

For electric service extensions to unserved areas, avoided costs are the sum of capacity and energy-related savings at the power generating level, plus the labor and materials cost of placing poles and transformers, added to any transmission and distribution costs caused by the extension of the system. These total costs of extending service in a conventional manner should be compared with the costs of stand-alone, renewable systems which provide equivalent service.

## Initiative #6: Tax Reform -- The restructuring of taxes currently imposed on utilities would make renewable resources more attractive to utilities.

Efforts to include environmental and other external costs in utility planning and resource acquisition often meet with stiff opposition from utilities and others. Replacing existing taxes with emission fees may provide a constructive means of accomplishing a similar result. State sales or gross receipts taxes now account for about five percent of total electric utility revenues. These taxes currently serve no specific purpose other than collecting revenues for state and local governments. Regulators, utilities, and state legislators should explore the use of emission taxes as a revenue-neutral substitute for these existing utility taxes. Such a tax would have a substantial positive impact on renewable development and pollution reduction.

## Initiative #7: Federal Support -- The Federal Energy Regulatory Commission should begin taking action to encourage the development of renewable resources.

Although most of the needed actions reside at the state level, one area, electricity transmission, is a matter for federal involvement. Development of non-renewables typically involves moving the power plant fuel (coal, oil, gas, or uranium) and then transmitting electricity. However, most renewable generation (hydro, wind, geothermal, and solar) occurs at the location of the resource. If transmission is viewed as a limited resource, it makes sense to adopt special preferential transmission rules to facilitate wheeling of electricity from renewable resources.

Also, pricing for transmission services might begin to include consideration of the environmental consequences of bulk power transactions. The FERC should consider higher prices for transactions that increase emissions and lower prices for those that lower emissions.

# BARRIERS TO RENEWABLES AT THE STATE LEVEL

## OVERVIEW

The barriers to the development of renewable resources cut across four broad areas:

1) Information concerning cost and performance of renewable resources is lacking;

2) Utility resource planning in general and avoided cost analysis in particular do not quantify even the direct economic value of renewable resources;

3) Resource acquisition processes (including bidding procedures and contract requirements imposed on purchases of power from renewable resource developers and other non-utility generators) tend to be biased against renewables; and

4) The regulatory process can be especially burdensome to renewable developers.

Conclusions regarding regulatory policies and utility practices which impair the development of renewable resources were drawn from a review of the approaches and experiences of a number of regulatory jurisdictions in addition to considerable hands-on experience in Maine.(4) Special attention was focused on a selected group of states identified in an earlier study as having significant renewable resource potential but very little, if any, actual development (excluding hydro).(5) Information was gathered from Commission Orders and Rules and from interviews with regulatory and utility staff.

Not surprisingly, the review of state regulatory and utility practices indicates that there is no single barrier to the development of renewable resources. Certainly, renewable resource development is frustrated by the lack of least-cost planning practices that accurately measure and compare the costs and benefits of all resources. Development is also hampered by all the problems facing other non-utility generators, not to mention the special difficulties unique to small facilities and less conventional technologies.

The development of electric generating capacity fueled by renewable resources varies widely throughout the country. In many states, development appears to be related more to state and utility planning and resource acquisition policies than the actual or perceived availability of renewable resources.

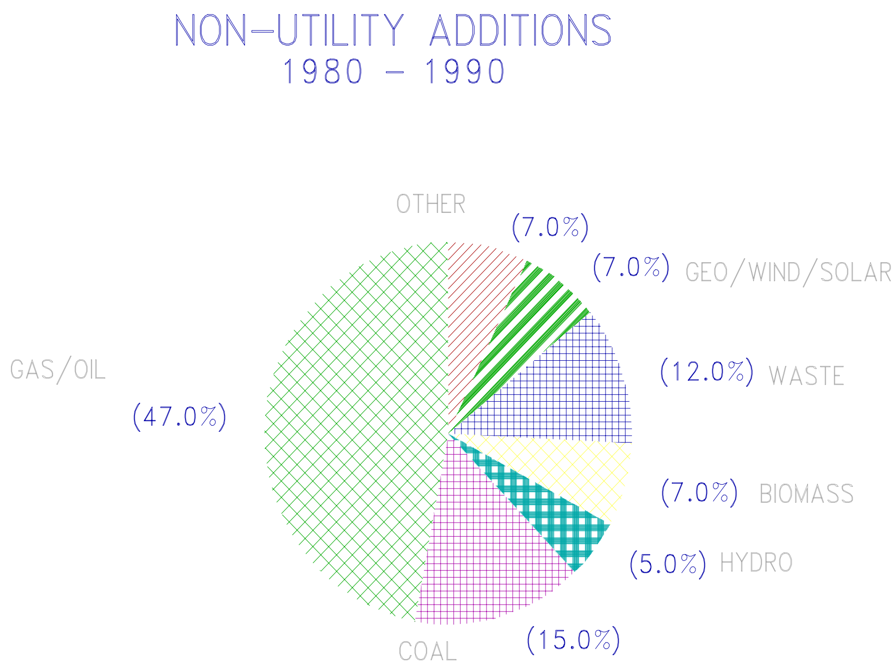
A review of advances in the electric utility industry in the last decade reveals that renewables have played a major and expanding role in certain states while having little, if any, success in other states possessing an equal or larger supply of the resources.

For example, California has developed a great deal of wind power, yet the wind resource is substantially better in the Great Plains states from North Dakota through Texas, where practically no wind power has been developed. Maine has developed substantial biomass energy, yet Washington, Oregon, Louisiana, and Georgia all have larger wood resources but very little biomass-fueled electric power generation.

California also leads the nation in the use of solar energy, both in the form of solar thermal and PV applications, yet the solar resource for both these technologies is better in Arizona, New Mexico, and parts of Texas.

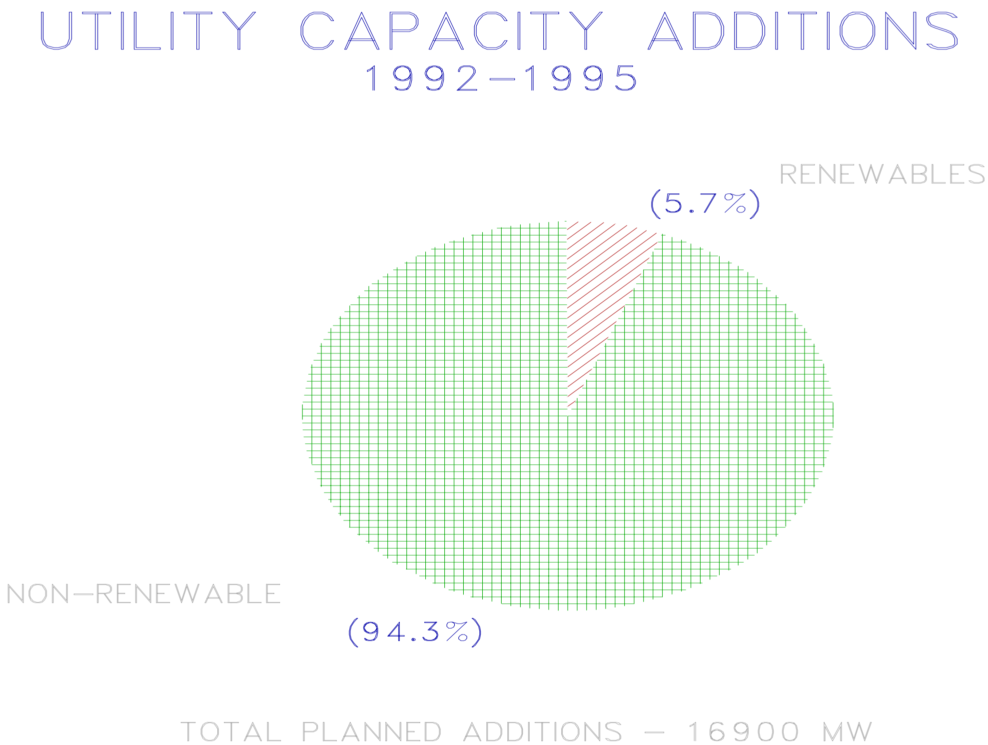
In general, the states which have been most successful in developing renewables are also the states that have most aggressively pursued least-cost planning and investment in energy efficiency. These are also the states which have the greatest amount of non-utility generation as a result of the implementation of PURPA.

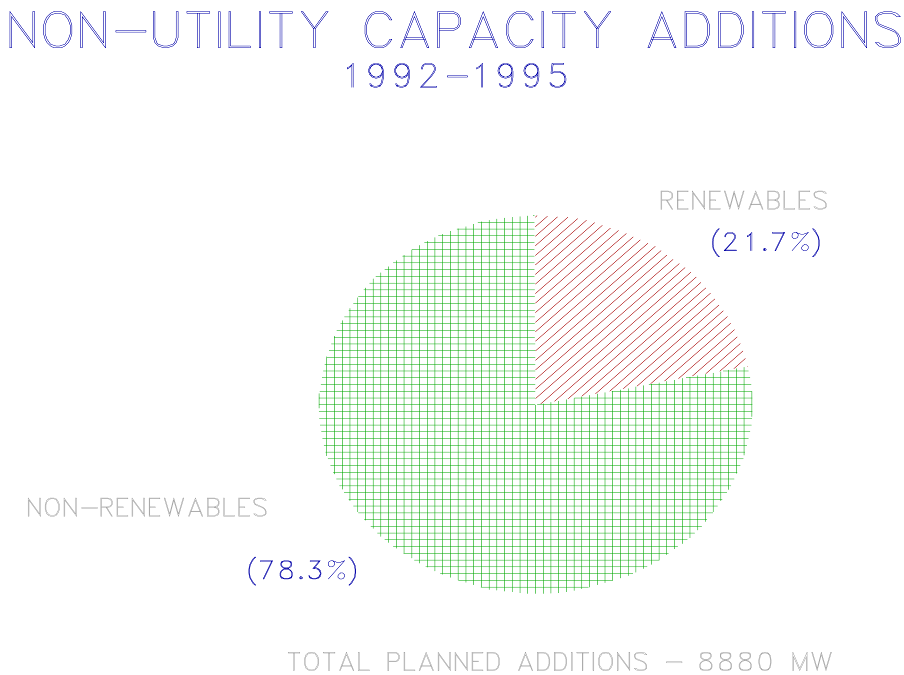
Qualifying facilities (QFs) under PURPA (which make up the vast majority of all non-utility




generation) are not all based on renewable energy but, as the following figures show, QFs or NUGs are much more likely to be renewables than are utility constructed generating facilities. Figure 1 shows the capacity mix that has been added by non-utility development from 1980 to 1990.[6] Over 30 percent of all NUG capacity additions have been fueled by renewable resources. (A portion of these resources are fueled with municipal waste, which perhaps should not be considered a renewable resource. However, the conclusions are the same even if these facilities are omitted.)

Figures 2 and 3 show the planned capacity additions by non-utility generators and utilities for 1992 through 1995. Over 26,000 megawatts (MWs) of new capacity will be added to the nation's electric generating capacity in that time. About one third of this new capacity will be owned and operated by regulated utilities. Little more than five percent of this new utility generation is to be fueled by renewable resources. By comparison, renewables used by non-utility sources will surpass 20 percent.






**Barrier #1: Information -- The lack of up-to-date and reliable information on the cost and performance of renewable resources means many renewables are completely ignored in the planning process.**

The fact that renewables have fared best where: 1) state and utility resource planning has been most subjected to Least-Cost Planning (LCP), and 2) utilities have acquired resources from NUGs (as opposed to locations with the most abundant renewable resources) is good news in two respects. First, it suggests that renewable development need not be limited to those few areas of the country with the most abundant natural resources. Second, it suggests that the most important barriers to renewables are in the resource planning and acquisition processes, which are largely within the control of state government and, unlike the distribution of natural renewable resources, relatively easy to change.

A February, 1991, NARUC study (Moskovitz and LaPorta)(7) was the first effort to identify regulatory barriers to the development of renewable resources. One of the most important conclusions of the study states:

> *A most significant impediment to the development of renewable energy resources is the lack of current information on the level of exploitable renewable energy resources as well as the cost, potential availability and performance of renewable energy systems. Few are aware of recent and very*

*significant improvements in cost and performance of solar thermal electric power plants, multiple wind turbine facilities, and geothermal and biomass energy power plants.*

*Without this information, utility regulators will make erroneous judgements about which potential resources receive serious consideration in integrated resource planning or in the formation of policies that will govern resource selection processes.*

Research and interviews conducted in connection with this report corroborate this conclusion. Many regulatory commissions and utilities are simply unaware of current information on renewable resources.

Since then, NARUC has taken the first step in making needed information available by preparing and distributing a photovoltaic technology handbook which gives regulators, utilities, and others detailed and current information on this key technology .

The impact of this information is clear. Several state commissions, including Arizona, Texas and Vermont, have already initiated efforts to assure that the information on cost-effective uses of PV systems is incorporated in utility planning and in the related rules and practices of the regulatory commissions.

Similar collections of current information should be made for other renewable technologies and distributed to regulators and utilities.

## Barrier #2: Planning -- Commonly used resource planning and avoided cost methods understate the value of renewable resources.

Central to all electric utility planning and resource selection is the concept of avoided cost. Alternative investment or purchase options are compared by examining how each option affects the utility's long-term costs. If the addition of a new resource displaces other capital or operating costs and, as a result, lowers the utility's total costs, the new resource, by definition, costs less than the utility's avoided cost.

Despite the widespread use of the term "avoided cost" by both electric utilities and regulators, the concept itself is frequently misunderstood and misapplied.

Regulators should reevaluate the methods used to define and measure utility avoided costs to ensure that cost-effective renewable resources are not being ignored.

**What is avoided cost?**

Too often "avoided cost" is treated as the cost of a utility's next proposed power plant. This is not only wrong but leads to the use of inappropriate analytical tools, inaccurate determinations of avoided cost, erroneous resource selection, and unreasonable contract terms, all of which lead to serious underestimation of renewables. This in turn can result in the rejection of cost-effective renewable resources, leaving consumers to pay for the higher cost default option.

Avoided cost can be calculated in many ways. One useful way to define avoided cost is the sum of the system expenditures that the utility would <u>not</u> incur if a new supply- or demand-side resource with zero costs were added to its system. Alternatively, avoided cost can be thought of as the reduction in total costs, if the level of electricity demand were reduced by an amount equal to the output of a new demand- or supply-side resource. These approaches are used in California, Massachusetts, Maine, and other states.

The utility's avoided cost is <u>not</u> simply the cost of a planned utility generating station. Depending on the resource being added, a utility's avoided cost can be substantially higher or lower than the cost of its next power plant. The precise avoided cost is a function of:

- The size and operating characteristics of the chosen resource,
- The timing of its addition to the system, and
- Its geographic location on the utility grid.

A hypothetical example borrowed from the cost/benefit analysis for a typical energy efficiency measure illustrates the importance of resource-specific determinations of avoided cost. Adding insulation to a previously uninsulated, electrically heated home might yield a reduction of 20 percent in kilowatt-hour (kWh) consumption and peak demand from that specific residence. As a result, the utility's fuel and capital costs for the next 30 years (the assumed useful life of the insulation) are lower by the amount of the saved energy.

How would a prudent utility planner modify the operation and expansion of the current system if the insulation resource were added? In the short-run, fuel use would be reduced; in the longer run, the timing and type of new power plants would change.

For a northern, winter-peaking utility the avoided cost (expressed in cents per kWh) of an insulation resource would typically be much higher than the cost of a new power plant. This higher value reflects the fact that cost savings resulting from the insulation occurs in the peak period and "avoids" the operation of the most expensive existing generating facilities, which will, at a minimum, delay the building of the next power plant. Because the resource (the reduced load) is located at the end of the utility's system, where voltage levels are lowest and power losses through wires and transformers are greatest, costs will also be saved throughout the entire transmission and distribution network. Avoiding on-peak line losses and substation upgrades can yield substantial cost savings.

If, instead of insulating her entire home, the same customer insulated just an electric water heater, the resulting utility cost savings would be significantly different. Because of the nature of a year-round water heater operation, a smaller proportion of the load reduction would be coincident with system peak demands (and costs). The probable result would be that the per-kWh avoided costs associated with the insulated heater would be smaller than those of the house insulation.

Establishing the same avoided cost level for both resources would have the effect of overstating the benefits of one while understating the cost savings of the other. Adding insulation to the electrically heated home might be more costly than either the utility's new power plant or the water heater insulation, yet it still turns out to be the most economic option when all of the costs and benefits are quantified. Yet, if the avoided cost analysis stopped at the cost of the next power plant, the high unit cost of the home insulation would have resulted in a rejection of the most economical option.

In the previous illustrations, energy efficiency examples were used because avoided cost analysis has become most sophisticated in the area of demand-side management (DSM). This same kind of analysis can be applied to the addition of a photovoltaic system to a home or the placement of a wind turbine near the end of a long and overloaded distribution line. The operating characteristics of these resources, combined with other direct cost savings, may mean that these resources are more economical than a conventional power plant.

Jargon attached to renewable resources often precludes the avoided cost analysis that might otherwise show that renewable resources are cost effective. Automatic exclusion of resources that receive labels such as "intermittent," "non-firm," "non-dispatchable," and "excess capacity" can lead to the elimination of valuable resources.

Dispatchability means that the hourly or daily electric output of the generating facility is under the direct control of the utility. Utility-owned conventional power plants are typically dispatchable; kWh output can be varied to follow changing system loads. (An exception is a nuclear power plant. While it may be under a utility's control, technical and economic constraints mean that the plant's output cannot be varied from hour to hour.) In contrast, the power generated by a PV system reflects the availability of usable sunlight and is therefore non-dispatchable.

**Jargon obscures the avoided cost analysis. Automatic exclusion of resources that receive labels such as "intermittent," "non-firm," "non-dispatchable," and "excess capacity" is a serious mistake.**

The term intermittent is related but not exactly the same as non-dispatchable. Wind is an example of a resource that is both intermittent (it produces power when the wind blows) and non-dispatchable (the utility has no meaningful way to schedule the output of the plant). A biomass-fueled cogeneration plant is an example of a facility that is not intermittent but may be non-dispatchable, due to the generating needs of the steam host.

Many states and utilities wrongly single out dispatchability as a unique and essential characteristic of supply-side resources. Because several renewable resources are non-dispatchable, any policy that gives undue weight to dispatchability biases resource selection against renewables.

In some states, dispatchability is a requirement for long-term contracts and in others it is a requirement for capacity-related payments. Still other states treat dispatchability as a primary non-price weighing factor in the ranking of resource options.

Properly structured avoided cost analysis or LCP studies can accurately assess the economic value of intermittent, dispatchable, and non-dispatchable resources.

All resources are, to one degree or another, intermittent in their operation, and different power plants have different levels of dispatchability. Nuclear plants are, for practical purposes, non-dispatchable. Coal plants respond to operator control much more slowly than do gas-fired or hydro-electric plants. Nevertheless, the value of each of these options can be identified using readily available planning models.

The same reasoning holds for intermittent resources. Unanticipated and unpredictable circumstances force conventional power plants, whether base load, intermediate, or peaking facilities, to be unavailable for service some significant fraction of the time. Capacity factors of 100 percent are nonexistent in the generation of electricity. Even very reliable conventional plants operate only 70 to 80 percent of the time.

Demand for electricity by individual customers is also intermittent. The operation of electrical equipment and appliances reflects consumer requirements and schedules without regard to the needs or particular conditions of the overall electric grid. Yet no one suggests that because customer loads are intermittent they impose additional capacity requirements. If intermittent loads impose capacity requirements, and they do, intermittent generation provides capacity benefits.

If one can forecast with reasonable accuracy the amount of power a plant produces and customers demand, readily available planning tools can quantify the value of the resources or the cost of serving the customer. There is, therefore, no need to impose rigid or arbitrary rules that non-dispatchable plants receive no capacity value. Dispatchability, like any other operating characteristic of a resource, will play a role in determining the value of a resource. Elevating dispatchability criteria above other potentially advantageous operating characteristics will, in all probability, hinder the development of renewable resources, which are more likely to be intermittent or non-dispatchable than conventional.

**How does the analysis differ if there is excess generating capacity?**

The term "excess capacity" is another example of a label that imparts more confusion than clarity to the process. Economic and utility planning analysis does not change when a utility system finds itself with more generating capacity than it needs.

A system is said to have "excess capacity" when it has more than the minimum level of capacity needed to meet system reliability needs. However, when LCP principles guide planning, "excess capacity" is defined in economic, not engineering terms. Resources are constantly being analyzed to determine if they continue to be economically competitive. If new resources are considered not "needed" because there is excess capacity, avoided cost proceedings are not held, bidding or other resource acquisition processes are put on hold, and information on the availability and cost-effectiveness of renewable generation is not kept current.

New resources (whether supply-side or demand-side) are acquired if the addition of the resource reduces the net present value (NPV) of the system's future costs.

In short, a new resource is "needed" whenever the cost of the new resource is less than the avoided cost. Even in the presence of a capacity surplus, fuel cost savings, reduced line losses, lower environmental compliance costs and transmission and distribution savings, can often justify the addition of new demand- or supply-side resources.

**What steps need to be taken to assure that the actual operating characteristics of intermittent and other renewable resources are incorporated into resource decision-making?**

The answer is simple and straightforward. Regulators should adopt and properly implement least-cost planning. At a minimum this means:

- Planning and avoided cost methods should be capable of identifying the real value of available renewable resources;

- Transmission, distribution, reliability, and other cost savings associated with the location of dispersed renewable resources should be identified;

- Planning and investment decisions should take uncertainty and risk into account and select a mix of diverse resources;

- Environmental benefits of renewable resources should be considered in resource planning and acquisition processes; and

- Methods of reflecting the comparative financial risks of different resources should be included in the planning process.

## Least-Cost Planning

Least-cost planning or integrated resource planning is a comprehensive utility planning process that considers the broadest possible range of demand- and supply-side resource options and selects the mix of resources that meets customer energy service demands at the lowest long-term cost. Weaknesses in existing planning methods that hamper the development of renewables can be corrected through a concerted effort to adopt and properly implement LCP practices.

At the heart of LCP is a substantially broadened consideration of supply-side and demand-side options as compared to traditional planning. The consideration of new options with characteristics different from conventional power sources means that a more detailed planning and avoided cost analysis necessarily accompanies the implementation of least-cost planning. These more detailed methods help identify opportunities for renewables. Of the five states with the most success in deploying renewables (excluding hydro-electric), four have least-cost planning processes in place (Rader, 1990).

According to the most comprehensive review of state planning activities, only 14 states have fully adopted least-cost planning (Mitchell, 1991). (EPRI and others report that 25 to 30 states have adopted LCP, but the definitions used are not as stringent as those in the Mitchell study.) More widespread implementation, along with the detailed planning and avoided cost analysis that accompanies least-cost planning, and a greater focus on the potential role for distributed (see discussion below) as well as centralized facilities, can expedite the development of renewable resources.

The adoption of least-cost planning without the use of appropriate analytical tools or resource acquisition policies, however, will not produce significant results. Many states that have adopted least-cost planning do not fully consider environmental impacts, risk factors, or distribution, transmission, and reliability benefits of renewable resources. In some cases, these benefits can exceed the capacity and energy savings which are often the only cost factors considered in many state least-cost planning evaluations.

## The "Distributed Utility" Concept

Traditionally, electric utilities are viewed from the perspective of generating capability, and secondarily, in terms of transmission and distribution facilities. However, looking at the utility from the customer's end of the system and considering the problems and opportunities of distribution will likely alter the way utilities and regulators assess the costs and benefits of resource alternatives.

The *distributed utility* concept, pioneered by Pacific Gas & Electric Company (PG&E), looks for cost savings and service opportunities from smaller, modular generation technologies often powered by renewable resources. While least-cost planning theoretically considers distributed savings, in practice these cost savings are often overlooked, perhaps in the mistaken belief that the savings potential is insignificant or is limited to a few isolated situations.

Regulatory recognition of (and emphasis on) the distributed utility concept will expand the understanding of cost avoidance to other factors. One simple way to accomplish this is to adopt regular reporting standards which require utilities to examine options to expanded transmission and distribution facilities.

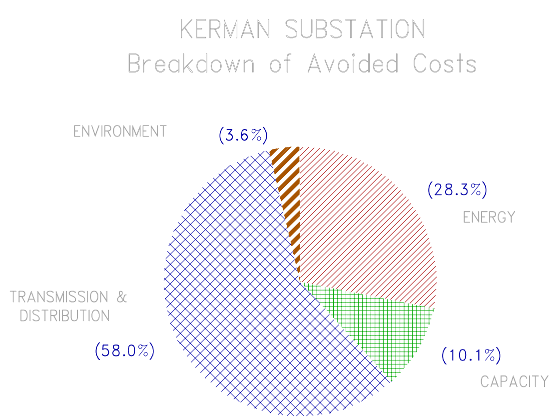
The distributed utility concept leads engineering and financial analysis of transmission and distribution costs toward minimizing the delivered, or customer-level, cost rather than the busbar (or average system power production) costs.

Non-generation cost factors to be considered in the analysis of the distributed utility include those found in alternatives to expanding, rebuilding, or reinforcing the transmission and distribution system. For example, transmission line losses may be decreased by virtue of renewable power generation at the customer end of the line. Likewise, system reliability may be increased by the geographic diversity of resources as well as by the variety of resource types dispersed throughout the grid.

**Adopt regular reporting standards that require utilities to examine options to expanded transmission and distribution facilities.**

Siting of dispersed renewable resources may also avoid costs otherwise imposed on new or upgraded distribution lines due to concerns with electric and magnetic fields. Such avoided expenditures might relate to the need for wider rights-of-way, relocations, higher transmission towers, and more expensive conductor sizes and configurations.

For example, in one notable study, Pacific Gas and Electric the installation of a dispersed PV system as an alternative to the costs of a new transformer and other related substation and distribution expenses. In this study, the peak power demand at the Kerman Substation closely matched the output of the PV installation. By carefully summing the "distributed benefits" calculated by the utility, PG&E's analysis concluded that the dispersed PV may be more economical than a conventional substation upgrade.




As shown in Figure 4, the overall transmission- and distribution-related cost savings associated with a PV installation exceeded generation related avoided cost. While the PG&E study involved PVs, careful siting of other renewables can lead to similar results.

The costs detailed in this analysis of the Kerman substation are not atypical. In 1991, Central Maine Power Company retained Asea Brown Boveri (ABB) to analyze the potential transmission and distribution (T&D) savings through geographically targeted energy efficiency programs. (DSM-related distribution system savings are similar to savings from strategically located generation.) The ABB study found that T&D savings were large, roughly equal to the generation-related cost savings.(8)

Expenditures for the routine upgrading of substations and associated distribution facilities represent a major utility investment. In 1990, investor-owned electric utilities spent over $9 billion on expanding and upgrading distribution facilities.(9)

To be sure, there are many instances in which remotely-sited renewables involve increased transmission costs. Allocating the full cost of added transmission facilities may ignore the reliability and other long-term benefits that accrue to the overall system. Commissions could establish policies and cost allocation methods that assure that transmission cost assignments do not bias resource selection. California is currently examining these issues in detail.(10)

Set-Asides

Utility planning is necessarily based on projections of future events. Everything from general inflation to fuel prices to interest costs to power plant performance to environmental laws must be forecasted. This means planning is risky because we all know that even the best forecasts will be wrong.

The response isn't to quit in frustration but rather to identify plans which may not be least-cost under just one set of assumptions but low-cost under a wide range of possible futures. This issue, the ability to fold risk assessment into the development of a good utility planning, has received a great deal of attention in recent years, but no objective method for trading off cost versus risk has as yet emerged, nor is one likely to. Instead, risk assessments have remained largely judgmental and subjective.

Despite its subjective nature, these risk-related concerns have already had a significant impact on utility planning. The past several years have seen a strong shift in favor of fuel diversification, particularly to natural gas and, in some regions, renewables. Simultaneously, we have seen utilities develop a general preference for smaller scale, often modular, projects with relatively short lead times between the decision to acquire a resource and the completion of construction. These decisions have, in significant part, been driven by a desire to reduce the risk exposures of utilities and their customers.

At the risk of being overly general, the decisions to shift to smaller scale gas-fired plants have been relatively easy. There do not appear to be any major scale economies of 1000 MW plants over their smaller, say 200 MW, cousins, while the natural gas market has been seen plenty of supply at relatively low costs. To date, the cost of risk reduction seems to be quite moderate.

How much diversity is enough and how much one is willing to pay in expected costs in return for reduced exposure to risk is a difficult call. Perhaps the most practical solution is achieved through renewable set-asides, a practice being used or pursued in at least five states.

In one fashion or another, set-asides require that a specified fraction of new resources acquired be reserved for renewables. The cost of the set-aside to consumers depends on the degree to which the planning methods already capture the direct benefits of renewables and the size of the set-aside. If the planning methods are already very sophisticated then the practical effect of a set-aside is to increase the direct cost consumers are expected to pay in return for reduced risk (plus of course many other indirect benefits, e.g. gaining experience with new technologies, research and development benefits, and lower emissions levels.

Environmental Externalities

Regulators and utilities should consider environmental costs in resource planning and in the acquisition and operation of supply-side resources.

Whether states adopt least-cost planning or rely more on conventional planning processes, resource selection should consider the full costs of all resource alternatives, including the environmental impacts of legally permissible emissions. As of December, 1991, only four states expressly considered monetized environmental externality costs in their least-cost planning processes. Perhaps another six states use non-monetized weighing factors to give preference to environmentally benign resources (Weil, 1991).

Estimates of the environmental cost of power production emissions vary considerably. For a new coal-fired power plant meeting existing federal pollution laws, estimates range from one to five cents per kWh. Incorporating these costs in resource selection decisions would alter resource selection.

With the notable exception of $CO_2$, emissions from new plants are much smaller than those of existing facilities. Yet most states which consider environmental costs limit the consideration to comparing the cost of air emissions of only those new resources. The higher external environmental costs associated with existing facilities are rarely considered.

Regulators and utilities should improve the analytical methods used to assess the relative risks of different resource options in the planning process. Two promising approaches involve the use of risk-adjusted discount rates and the "perpetual option" model recently described by the researchers at the World Bank (discussed below).

Risk-adjusted Discount Rates

Typically, least-cost planning and avoided cost analysis compare the net present value cost of all resource options using the same discount rate, a value that is normally assumed to be the utility's weighted average after-tax cost of capital. Using a uniform discount rate for analyzing different resources may bias the outcome in favor of conventional low capital cost technologies.

Financial theory, however, suggests that the value of different resource options should be calculated using project-specific or "risk adjusted" discount rates. For example, every day investors weigh the riskiness of different stocks and bonds and bid prices for particular investments up or down based on perceived risks of future cash flows of their investments. The greater the risk of future cash flows, the less an investor will pay for a stock or bond.

Applying this approach to resource planning means that different resource options should be evaluated using project or technology specific risk adjusted discount rates (Awerbuch, 1991).(11) EPRI reports also urge commissions and utilities to use project specific discount rates.(12)

**The value of different resource options should be calculated using project-specific or "risk adjusted" discount rates.**

Different power plants and technologies expose investors and consumers to different risks due to the length of the construction period, uncertain in plant operation, and the associated effect on cost recovery, recovery of fuel and other operating costs, and future decommissioning costs. The risk of future environmental costs are important to consider, especially efforts to limit emissions of carbon dioxide and other greenhouse gases. A recent letter signed by twelve leading national consumer and environmental organizations warned utilities of the need to account for the prospect of future regulation.

**NUCLEAR DISCOUNT RATE**

Nuclear power provides a stark example of how the risk from a single power plant investment can impact a utility's overall cost of capital. During the mid and late 1980s utilities with heavy nuclear commitments paid a 50 to 100 basis point premium for capital, compared to non-nuclear utilities. These additional capital costs can have a substantial impact on corporate earnings and equity values. As of December 1, 1991, the common stock of Portland General Electric, an Oregon utility with a significant nuclear investment plagued by operating problems and political opposition, sold at 80 percent of book value while the market to book ratios for the industry as a whole was over 140 percent of book value. If the impact on a utility's overall cost of capital is 100 basis points, the implied risk of the nuclear part of the utility's resource portfolio is very substantial.

Risks imposed by different resources may also hinge on whether the resource is utility owned or owned by a NUG -- and, if owned by a NUG, how the power sales contract allocates risks between customers, the utility, and the NUG. Many risks, such as construction cost overruns and power plant performance, which are normally borne by utilities have, in recent years, been contractually shifted to NUGs. In the case of a recent competitive solicitation, bidders were explicitly required by the Bonneville Power Authority to bear the risk of future regulation of greenhouse emissions.

Investor and consumer risks relating to capital cost recovery are relatively predictable and therefore are comparatively low risks. Estimates of operating costs, on the other hand, are based on uncertain assumptions of future fuel price escalation rates for coal, oil, and natural gas. Even small departures from assumed fuel price escalation rates can alter resource selection.

Renewable resources are not without their own unique risks. The utility experience with renewable technology is relatively low, except for hydro and some biomass technologies. The risk of long-term plant performance is therefore high. All risks, including technological, fuel cost, environmental, contractual, and performance risks, need to be assessed on a technology- and plant-specific basis.

Value of Options

A second approach to analyzing risk and uncertainty was recently described by researchers at The World Bank.[13] The World Bank is a major source of capital for large power projects around the world. As such, The World Bank is rightfully concerned about investing large sums of capital in projects that turn out not to be least-cost.

The World Bank wishes to avoid what it calls the problem of "irreversible" investments. The report notes:

> *Conventional analysis techniques, including standard least-cost power planning, ignore the cost of the lost option. Yet the value of the option to "wait to invest" could be large enough to invalidate the usual decision rule, to invest when benefits exceed costs. In effect, the correct decision rule under such circumstances should be to invest when benefits exceed costs by an amount at least equal to the value of the lost (foregone) option.*[14]

The World Bank is assessing a specific approach to quantifying the economic value of options provided when small, modular, and short-lead-time generating alternatives delay or replace large capital-intensive projects having long construction periods.

The approach was tested on four case studies, each involving multiple proposed power projects. The studies applied financial models to compare two investment scenarios: one, a large irreversible project such as a nuclear or large hydro plant, and the other, a number of small modular plants.

For about half the projects, the quantified value of the flexibility inherent in small modular generating options reversed the prior decisions relating to the cost effectiveness of large hydro and nuclear facilities.

Least-cost planning principles stress the importance of considering uncertainty, risk, and flexibility. Translating these variables into a quantitative process has heretofore been a missing element in least-cost planning. Risk-adjusted discount rates and the options value approach appear to be useful refinements to the least-cost planning process.

Whatever the final result, consumers will benefit and least-cost planning results will be more informative and robust if the relative risks of different resource options are properly considered.

<u>Technical Assistance Program</u>

The original version of this report called upon the Department of Energy and others to establish or expand technical assistance programs designed to increase the planning skills and understanding of renewables by utilities, commissioners and their staffs.

Many of the most persistent barriers to the development of renewable resources are related to the lack of relevant training, experience, and resources at state regulatory commissions. Assistance is needed to develop the following capabilities at the state level:

This suggestion is being pursued by agencies of the federal government through support of The Regulatory Assistance Project and other similar efforts. This activity is critical because it provides:

- A more comprehensive understanding of least-cost planning methods and tools;

- More sophisticated avoided cost methods which permit accurate economic evaluations of alternative resources;

- Added capabilities to analyze and quantify the economic value of distributed resources;

- Reliable, up-to-date information on the availability, cost, and performance of renewable resources; and

- Reliable information on the contract and financial requirements of renewable resources.

Without progress in these areas, regulators will have very little success in accelerating the use of cost-effective renewable resources.

## Barrier #3: Acquisitions -- Resource acquisition practices are biased against renewables.

If renewable resources are developed by non-utility developers, the power sales contract will define the economic and operational relationship between the utility and the renewable facility. The price and non-price terms of the contract and the time and expense of negotiating the contract will determine whether the contract is ultimately signed and whether the project can be financed and successfully completed.

Price terms which determine the timing and pattern of utility payments (as distinguished from overall price levels) can have an especially strong influence on which technologies are economically viable. If contract payment streams are incompatible with the financial characteristics of a particular resource, a technology that is economic may be ruled out.

Non-price issues are also important, particularly security provisions, insurance requirements, the maximum length of contracts, reopener clauses, and provisions describing conditions under which generation may be suspended. Unreasonable requirements in any of these areas can raise the cost of a renewable resource beyond the point of cost effectiveness or make it impossible to finance and construct a desirable renewable resource.

**What are front-end loaded contracts and why are they important for the development of renewable resources?**

Avoided cost calculations, which often form the basis for contract prices, are typically stated as a stream of 15 or more annual figures. A levelized contract payment takes a stream of generally escalating annual avoided cost figures and restates it as a single price per kWh which, if held constant for the duration of the contract, yields the same present value as the original calculations.

Front-end loaded contracts provide for power contract payments which exceed utility avoided costs during the initial years of the agreement and then decline in subsequent years, leaving the present value of payments unaffected. (Levelized contracts are typically also front-end loaded contracts.) As a general matter, the more capital intensive a technology, the more the need for front-end loaded types of contracts.

Because front-end loaded contracts provide for near-term payment levels in excess of avoided cost, potential suppliers are sometimes prohibited or, at a minimum, discouraged from participating in a resource acquisition processes. This is accomplished by the imposition of negative weighing factors or by additional financial security requirements.

Tables 1a and 1b can be used to illustrate the problems caused by regulatory or utility policies that preclude renewable projects from receiving front-end loaded payments. These tables present a simplified example of how traditional utility planning compares three resource options: a hydro-electric resource, a biomass plant, and a gas-fired combustion turbine. The resource options are shown in Table 1a. Table 1b shows the calculated annual costs for a ten year period based on typical utility accounting.

**Table 1a: Resource Option Assumptions**

| | Hydro-electric | Biomass | Natural Gas |
|---|---|---|---|
| Capital Cost $/KW | 2,000 | 1,000 | 500 |
| First Year Energy Cost/kWh | 0 | 0.03 | 0.05 |
| Fuel Cost Escalation | 0 | 0.05 | 0.07 |
| Annual kWh | 5,000 | 5,000 | 5,000 |

Assume the hypothetical utility currently plans to pursue the gas-fired combustion turbine option. Under this base case, the new gas turbine is added in Year 3, the first year new capacity is needed. Thus, for the first two years of the base case, no capacity costs are incurred. The energy costs for the first two years shown in column 9 are the system energy costs incurred with no new capacity additions.

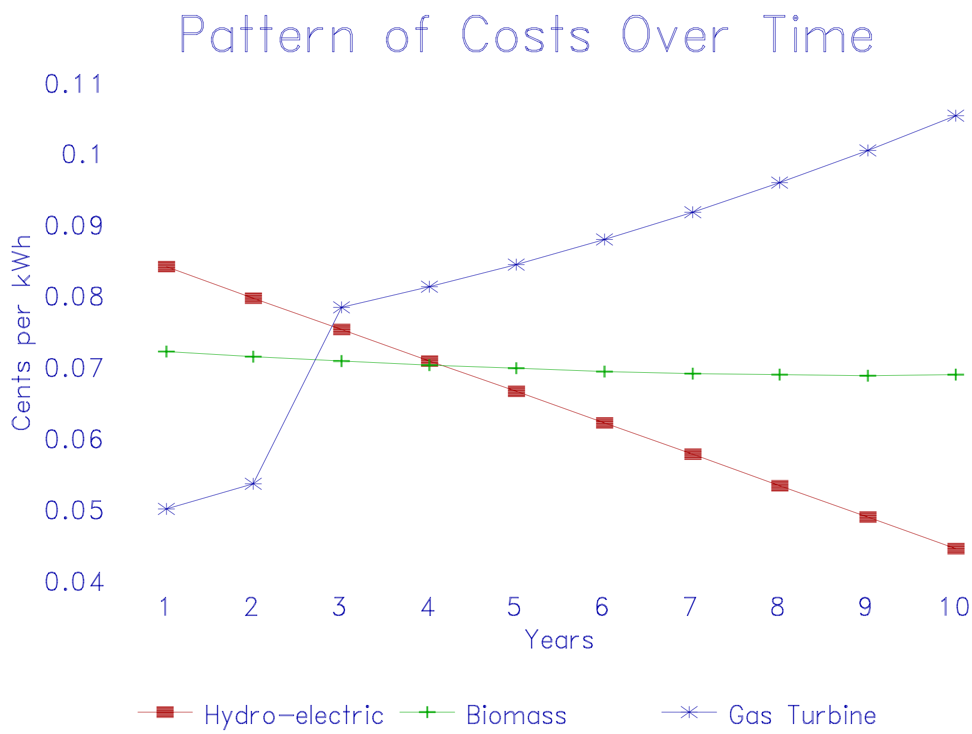
**Table 1b: Total Annual Cost of Resource Options**

| | Hydro-electric Option 1 | | | Biomass Option 2 | | | Natural Gas Combustion Turbine Option 3 (BASE CASE) | | |
|---|---|---|---|---|---|---|---|---|---|
| **Year (1)** | **Cap. (2)** | **Energy (3)** | **Total (4)** | **Cap. (5)** | **Energy (6)** | **Total (7)** | **Cap. (8)** | **Energy (9)** | **Total (10)** |
| 1 | 0.084 | 0.000 | 0.084 | 0.042 | 0.030 | 0.072 | 0.000 | 0.050 | 0.050 |
| 2 | 0.080 | 0.000 | 0.080 | 0.040 | 0.032 | 0.071 | 0.000 | 0.054 | 0.054 |
| 3 | 0.075 | 0.000 | 0.075 | 0.038 | 0.033 | 0.071 | 0.021 | 0.057 | 0.078 |
| 4 | 0.071 | 0.000 | 0.071 | 0.035 | 0.035 | 0.070 | 0.020 | 0.061 | 0.081 |
| 5 | 0.066 | 0.000 | 0.066 | 0.033 | 0.036 | 0.070 | 0.019 | 0.066 | 0.084 |
| 6 | 0.062 | 0.000 | 0.062 | 0.031 | 0.038 | 0.069 | 0.018 | 0.070 | 0.088 |
| 7 | 0.058 | 0.000 | 0.058 | 0.029 | 0.040 | 0.069 | 0.017 | 0.075 | 0.092 |
| 8 | 0.053 | 0.000 | 0.053 | 0.027 | 0.042 | 0.069 | 0.016 | 0.080 | 0.096 |
| 9 | 0.049 | 0.000 | 0.049 | 0.024 | 0.044 | 0.069 | 0.014 | 0.086 | 0.100 |
| 10 | 0.044 | 0.000 | 0.044 | 0.022 | 0.047 | 0.069 | 0.013 | 0.092 | 0.105 |
| NPV | 0.400 | 0.000 | 0.400 | 0.200 | 0.213 | 0.413 | 0.074 | 0.384 | 0.458 |
| Level'd | | | 0.068 | | | 0.070 | | | 0.078 |

Table 1b and Figure 5 show that traditional utility accounting practices cause the capacity portion of costs to start out high and slowly decline over time as the original investment is depreciated. In contrast, the energy component of costs, comprised primarily of fuel costs, typically escalates over time with inflation. In this example, the cost of natural gas is assumed to escalate at a rate slightly faster than the cost of biomass.

The total annual cost of each case is the sum of energy and capacity costs. Total costs either escalate or decline based on the combined capital and fuel costs of the option being considered. Figure 5 shows the pattern of combined capital and fuel cost streams in cents per kilowatt-hour for each of the three options.

The last two lines of Table 1b show the net present value of the ten-year stream of costs and the levelized cost for each option using an assumed weighted capital cost of 11 percent for each option. The NPV calculation allows decision makers to compare the total cost of alternatives having different costs in different years. The levelized cost shows the equivalent cost of the option if the annual costs were constant throughout the time period.




**Why are renewable resources biased by prohibitions on front-loaded contracts?**

Assuming that non-monetized issues such as fuel diversity, risk, and environmental impact are equal for all options, both conventional utility planning and least-cost planning dictate that the utility should select Option 1, the hydro-electric resource, because it has the lowest net present value cost. The second choice would be Option 2, biomass. The most expensive choice would be the gas turbine option.

If Option 3 were considered the utility's avoided cost and Options 1 and 2 were bids from proposed renewable developers, both lower cost options would be front-end loaded. This is shown in Figure 5, where the costs of the hydro-electric and biomass resources exceed the gas turbine costs in years one and two. Any prohibition on front-end loaded contracts would eliminate the renewable resources from further consideration, even though both options would be less costly than the utility's option.

**Why is it acceptable to pay avoided capacity costs prior to the time capacity is needed?**

Prohibiting the payment of avoided capacity costs until the time utilities would have incurred new capacity-related costs is another way to obstruct front-end loaded payments. Referring to Table 1b, this means that the total dollars allowed to be paid in years one and two would be limited to the energy costs shown for years one and two of the base case (Option 3, Column 10).

**Higher capacity costs may substitute for energy costs whenever total costs are reduced.**

Artificially restricting the timing of contract payments based on whether the avoided cost is capacity or energy related is inconsistent with sound utility planning and will necessarily lead to higher total costs. Resource and investment decisions are made on the basis of *total costs* without regard to whether a particular dollar of cost is related to capacity or energy. Higher capacity costs may substitute for energy costs whenever total costs are reduced.

**If power isn't "needed" for two years, why shouldn't the acquisition of renewable resources simply be delayed?**

Many states and utilities erroneously postpone competitive bidding or other resource acquisition (along with rulemakings and other regulatory proceedings involving least-cost planning) until the "need" for power is current.

The fact that capacity is not "needed" for the first two years is largely irrelevant. Proceeding with the hydro option shown in Table 1b -- despite its higher short-term capacity costs and even in a period of no "need" -- the hydro option remains the preferred course of action because of its lower long term costs. The question of need for new resources is answered in economic terms, not by a simple balancing of supply and demand.

The question of need for new resources is answered in economic terms, not by a simple balancing of supply and demand.

Delaying the construction of the hydro-electric plant for two years until capacity is "needed" is typically not the best solution. The 10-year levelized cost for the hydroelectric project increases from .40, as shown in Table 1b, to .404 if the plant were delayed for two years, even if construction costs escalated at rates below the rate of inflation.

There are conditions under which it makes sense to delay the addition of a cost-effective resource. Indeed, one of the benefits of small modular renewables is the value of planning and construction flexibility provided by short lead times. (See previous discussion of value options.) There are, however, also conditions under which customers are not benefited by delay, even after consideration of the value of options. Each case must be analyzed separately. A general policy that assumes consumers are always better off delaying a cost-effective resource until new capacity is needed will lead to higher, not lower, consumer costs in many cases.

Even when it seems to make economical sense to delay a resource acquisition, practical constraints may rule against delay. For example, FERC hydro-electric licensing rules impose strict schedules which may not allow for delay; there may be a need to coordinate schedules with the requirements of a cogeneration steam host. The simple need to coordinate resource additions with transmission and distribution system requirements is another example of a circumstance which may require adding cost-effective resources immediately, as opposed to later, even though a delay may appear to provide economic benefits.

**How can security requirements in long-term contracts impede renewable development?**

Having security provisions in power contracts is one way of ensuring that renewable resources will be built on time, perform as expected, and operate for the full term of the contract. Security provisions are equivalent to insurance policies or performance bonds that guarantee contract compliance on the part of the developer. As with insurance, the more extensive the coverage required, the greater the cost to the resource developer. Problems occur when the cost of security is made so high that it exceeds the benefit to customers and makes a cost-effective renewable project appear to be too expensive.

Are utility projects subject to security requirements?

The security requirements imposed on NUG projects have no parallel to projects owned and constructed by the utilities. Electric utilities do not set aside separate security or acquire commercial insurance against the possibilities that:

- Power plant construction will not be completed as originally planned;
- Fuel cost and availability will be as originally predicted;
- Plant capacity factors will fall short of original expectations; or
- A plant will cease to operate before it reaches a break-even point.

Absent imprudence on the part of utility management, the costs and risks connected with such events are typically borne by customers.

The decision to place the responsibility for these risks on NUG developers instead of consumers merely shifts the risks from one party to another.

In the case of utilities, the risk is borne directly by consumers and does not appear as a cost of the utility power plant. In the case of NUG development, however, the risk is borne by the developer and is reflected in higher prices for power. Shifting the risk from one party becomes a problem if it biases resource selection.

**What security guarantees should be required?**

The underlying concern that gives rise to security requirements is legitimate and is intended to protect consumers from expensive failed investments for which they otherwise would have to bear the financial repercussions. It is possible to address the need to insure without discouraging the development of renewable resources. In particular, the needed level of security can be provided by structuring contract payments so that the energy-related payments (the portion of the contract price paid on a per kWh basis) always exceed the energy (or variable operating) costs of the producer.

Following this simple pricing principle means that it will always be in the NUG's financial interest to continue operating the plant. The more reliable the plant and the more it operates, the more profitable the plant will be, even if the initial project developer fails or goes bankrupt. Security is thus built into the economics of the project and the contract, instead of being added after the fact.

Applying the rule that energy-related payments be designed to exceed operating costs means that technologies characterized by low capital costs and high operating costs would receive the least front-loading. High contract prices would be needed in the late years of a project's life to pay for the anticipated higher fuel and operating costs. Capital intensive projects such as hydro, PV, wind, and solar thermal projects would receive more heavily front-end loaded pricing because operating costs represent a relatively small part of the projects' overall costs. Of the states reviewed, only New Jersey recognized and addressed this issue.

**Why not simply require that utilities retain the right to take projects over if developers default on contract requirements?**

Several states require that utility contracts with NUGs give utilities the legal right to take over and operate facilities upon contract default. Unfortunately, at best, this type of contract requirement provides a false sense of security and at worst makes it difficult or impossible to finance projects.

If the project is abandoned because the original contract price is inadequate to cover the project's operating costs, subsequent utility operation is a good solution only if the utility is a more efficient operator and can reduce the operating costs below the contract price. If the utility is unable to operate the facility more efficiently, consumers would be better off to renegotiate a higher price that at least covers the plant's operating costs provided that the new price is at or below the utility's current avoided costs.

**Why are renewable resources hampered by limitations on contract duration?**

When renewable resources are developed by NUGs, the debt portion of the financing must be repaid several years before the end of the contract to allow for unforeseen events. The long asset life of most renewables means that limitations on contract duration, such as the ten and fifteen-year limit imposed by some states, require the debt financing to be repaid in seven to twelve years. Given that the cost-effectiveness of new renewables is based on a twenty- or thirty-year useful life, requiring that debt be retired in seven to twelve years can make it difficult if not impossible to develop certain renewable resources.

**Short contracts for utilities?**

When an electric utility constructs a power plant, a contract, created by regulation, is implied by law between the utility and ratepayers and its duration is the useful life of the plant, typically thirty to forty years. Absent imprudent management or extraordinary circumstances, the electric utility will recover the capital and operating cost of the plant over its entire life. A regulatory contract that: 1) limited utility cost recovery to ten or fifteen years, 2) restricted cost recovery to avoided costs during that period, and 3) had uncertain cost recovery thereafter would put an end to virtually any utility power plant construction.

**How do contract provisions that reopen contracts and modify power prices when avoided costs fall prevent the development of renewable resources?**

Several states and a number of electric utilities require that power sales contract prices be subject to modification or termination upon the occurrence of specified events. For example, contract payments would be lowered if avoided costs drop below a specified level. Other terms may cancel or terminate contracts if regulators disallow the purchasing utility's full cost recovery. The cash flow uncertainty created by these provisions makes it prohibitively expensive to obtain financing for what would otherwise be cost-effective renewable resource projects.

Ordinarily, the risks undertaken by developers of renewable resource projects relate to the developer's ability to complete the project in a timely and cost-effective manner and to operate the facility reliably over the term of the contract. Lenders can evaluate these risks and judge whether the project's expected operation and resulting revenues will service the loan. If lenders must also assume the risk of changed avoided cost or regulatory disallowances, the project will not be financed.

### Utility risks

The risks imposed on renewables by contract reopening clauses contrast sharply with those assumed by utilities when they construct their own capacity, purchase power from other utilities, or acquire goods and services from private vendors. Absent extraordinary circumstances, the utility's power plant cost recovery is not adjusted upward or downward if future avoided costs are different from the estimates made at the time the plant was constructed.

Utility equipment vendors and construction contractors also do not have the risk of contract payment termination or adjustment in response to regulatory disallowances. If General Electric, a turbine vendor, were required to bear the risk of regulatory disallowances for a project built on time and within budget but which was no longer cost effective due to fuel price or other forecasting errors, it would either refuse to be the supplier or adjust the turbine price substantially to compensate for the increased risk of utility nonpayment.

**Under what conditions should a utility be allowed to stop purchasing power from a renewable facility?**

The federal rules adopted by the Federal Energy Regulatory Commission (FERC) implementing PURPA allow utilities to cease making purchases when the result is increased costs. This provision has been erroneously interpreted in some states to mean that utilities may refuse to purchase power during any hour in which power can be produced or acquired at a cost less than the contractual price paid to the NUG.

For example, if a renewable developer signs a long-term contract at a levelized price of five cents per kilowatt-hour, some states allow the utility to cease making purchases whenever the utility's alternative cost is less than five cents. Stating that the average, or levelized, avoided cost is five cents per kWh simply implies that about half the time the instantaneous avoided cost is above five cents and the rest of the time the avoided cost is below five cents. Setting the price for a renewable developer at the average of five cents and then not paying the five-cent price during the roughly 50% of the time that avoided costs are less than five cents is clearly unfair. Cost-effective renewable resources, i.e. those costing five cents per kWh or less on a levelized basis, would not be developed if these contract terms were imposed.

The purpose of the FERC rule is to permit a utility to cease purchases under very limited circumstances and even then, only if notice is first given to the NUG. For example, purchases might stop during very low load periods for a utility with a large amount of nuclear capacity, where for a few hours costs would increase if loads on the electric utility system decreased. During these hours the utility's avoided cost is negative.

**Addressing Acquisition Barriers**

The simplest way to address the identified barriers is for regulators and utilities to develop standard contract terms and conditions. Standard contracts can greatly minimize transaction costs and provide a convenient, efficient, and direct way to examine acquisition issues and to convey state and utility policies to developers and the financial community.

**LESSONS FROM LUZ**

**In July, 1991, LUZ International Limited, a company with nine solar thermal power plants (totaling 355 MW of operating capacity) representing 95% of the world's solar generated electricity, filed for bankruptcy protection and ceased all development of new power projects. The full story of what led to the fall of LUZ has been told my Michael Lotker, LUZ's former Vice President of Business Development.* Of the nine principal barriers contributing to LUZ's bankruptcy, only three relate to utility and regulatory obstacles. The remaining six barriers involved federal and state tax laws and restrictions in PURPA, the Public Utility Holding Company Act, and other federal laws.**

**The regulatory barriers described by Lotker are combinations of several of the barriers described in this report.**

**1) California terminated the availability of levelized contracts (or other contracts that which allowed payments to QFs to be tied to the utility's projected avoided cost) without regard to whether the utility cost avoided was fuel or capacity related. When levelized contracts were allowed, they were limited in duration to ten years. These restrictions to contract payment terms increased LUZ's financial costs significantly.**

**2) Fuel adjustment clauses and prior regulatory decisions of the California PUC imposed low risks on utility selection of fuel-intensive options and high risks on utility selection of capital-intensive resources. Using risk-adjusted discount rates would have led to the opposite result.**

**3) Consideration of environmental externalities in California and nearby markets was too little, too late.**

*** Lotker, Michael, *Barriers to Commercialization of Large-Scale Solar Electricity: Lessons Learned from the LUZ Experience*, Sandia National Laboratories, Nov. 1991, Westlake Village, CA.**

The availability of standard contracts can be especially helpful to small scale renewables with installed capacities of 10 MW or less.

Rules or policies that govern front-end loaded contract payments, permissible pricing structures, and security provisions can all be considered in an integrated fashion when standard contract options are developed.

**The simplest way to address the identified barriers is for regulators and utilities to develop standard contract terms and conditions.**

Finally, some of the regulatory policies that hinder the increased use of renewables are caused by a lack of information on the practical and financial constraints faced by renewable development. These barriers can be overcome with more and better information.

Other regulatory policies may be the result of misplaced efforts to protect consumers from the risk of errors in estimating future avoided costs. If these efforts apply exclusively to NUGs (and not to utilities as well) resource selection will be seriously biased, consumer risk will be increased rather than reduced, and overall economic and environmental costs will be higher. Side-by-side comparisons of consumer risk under conventional utility versus non-utility development help inform policy makers of the risk and cost implications of resource acquisition policies.

**Barrier #4: Process -- The time, expense, and credibility of the regulatory process can be a special problem for renewable resources.**

The regulatory process itself can be both a hindrance and a benefit to renewable resources.

On the positive side, the presence of a simple and efficient regulatory process can help resolve disputes that arise during the course of good faith negotiations. Commission rules clearly articulating state policies toward renewable resources, specifying what is expected of utilities and what consequences will fall on non-complying parties, can also help assure speedy and successful contract negotiations.

Developers of renewable projects focus their activities in states which they believe are likely to conclude contract and licensing procedures rapidly. Their judgment is based on their perception of the credibility and attitudes of state regulators and the local electric utility.

Developers of renewable resources are often not experienced with the different regulatory and utility planning processes which exist in each state. Public utility commission proceedings can be time-consuming and expensive, and regulations or other requirements that demand active involvement in commission proceedings can become a substantial barrier. Consequently, regulatory practices should be designed to avoid or minimize the need for direct involvement on the part of non-utility developers.

The credibility of the regulatory process is a major factor in establishing a viable process for acquiring non-utility resources. The contents of state regulations are important, but even more important is the demonstrated experience of state regulators in implementing a resource acquisition process. States with time-consuming, expensive and unpredictable processes are least likely to result in new renewable resources.

## NEW INITIATIVES

This section describes six broad policy initiatives regulators and utilities may use to accelerate the development of renewable resources. The initiatives are separate but complementary, and the proposals can be pursued individually or in any combination. The initiatives are listed in general order of importance.

The initiatives are described independent of the barriers because they are not aimed at correcting or removing specific barriers directly. Rather, these initiatives seek to accelerate renewable development whether or not the barriers previously identified are successfully removed.

In part, these initiatives circumvent the ordinary process of removing barriers. For example, potentially burdensome contractual requirements may be reviewed in a commission proceeding. If utilities (or other major parties) are hostile to renewable resources or NUGs, the proceeding may become expensive, time consuming, and lead to an inferior outcome. The supply-side incentive described in Initiative #2 may be a much quicker and more efficient route to a more reasonable set of contract terms.

By increasing the use of renewables through the use of these initiatives, regulators, utilities, and the public will more quickly learn of the valuable contribution renewables can make. With this experience and education, attention can turn to removing barriers.

### Initiative #1: Green Pricing -- Green pricing options will give the consumer the choice to use renewable resources.

Regulators and utilities should experiment with innovative "green pricing" optional rates which give consumers a choice of increased reliance on renewables.

The marketing of the green pricing option can combine with efforts to educate customers about the benefits of renewable resources. Marketing information will make it clear that many renewables are already cost effective and are being acquired, and that green pricing is aimed at technology or applications that are not yet cost effective.

In recent years a higher level of environmental awareness has resulted in the proliferation of new environmentally friendly products and services for consumers. In grocery stores, for example, shoppers now have the option of purchasing conventional food and paper products or, if they pay a small premium, they can purchase more environmentally safe products such as organically grown produce or recycled paper. The success of this approach in retail merchandising, and the demonstrated consumer willingness to pay slightly higher costs in return for environmental improvement, provides a simple and practical approach to accelerating the development of renewable resources.

## A Model

Applying the same grocery store principle to electricity, consumers could be offered an optional environmentally preferred electricity service. The optional electricity rate might be called "green" power.

Customer surveys suggest that twenty-five to fifty percent of consumers are willing to pay a ten percent or higher premium for electricity produced in a environmentally safe manner. An experiment with green pricing could provide customers with a separate renewable option to test whether these survey results accurately reflect actual consumer behavior and choices.

A project funded by the U.S. DOE is now working on developing detailed green pricing pilot programs in four states, based on input from utilities, regulators, environmental and consumer groups, renewable developers, and targeted market research. Appendix A is a detailed description of the experience thus far.

Consumers will be given the option to buy a different class of electrical service priced perhaps ten percent above the cost of their existing retail service. In return, the utility modifies its resource acquisition plans and acquires sufficient new and incremental renewable resources to displace these customers' pro-rata share of fossil fueled resources.

For example, if 65% of the utility's existing energy production is generated through fossil fuels and the customer consumed 1000 kWhs per month at a price of 10 cents per kWh, the customer could agree to pay 11 cents per kWh if the utility acquires enough renewable resources to provide 650 kWhs (65 percent times 1000 kWhs).

In this example, the customer would pay one cent more per kWh, or a total of $10.00 more per month total, but the utility only needs to acquire 650 kWhs of new renewables to displace the customer's share of fossil fueled resources. This means that the utility can spend about 1.5 cents more per kWh ($10.00/650 kWh) than its ordinary cost of power before any additional costs are incurred that might fall upon other customers who do not opt for green power.

To help market green prices to customers, green-colored or other distinctively designed bills can be used. Commercial and industrial customers could also have the green option and could be allowed to market their products as having been produced with green power. Participation in this program might provide certain customers a marketing advantage in an environmentally aware marketplace. Utility-provided tags or stickers with the "Green Power" logo could be made a part of the program. Utility advertising programs aimed at marketing green power might also identify commercial and industrial customers who have signed up for the green pricing option.

Marketing green pricing is primarily the obligation of the electric utility, but joint marketing with environmental groups or government agencies would add to the program's appeal.

**Utility Obligations**

Under green pricing, a utility has three primary obligations: 1) to acquire the amount of new renewable energy demanded by participating customers, 2) to use the revenues collected through the rate premium for the purchase or acquisition of new renewable resources, and 3) to procure new renewable resources in the most cost-effective manner possible. Green-colored requests for proposals (RFPs), described in a later section, could be used to ensure that renewable resources are acquired in the most cost-effective manner.

Green pricing is not a substitute for continued least-cost planning efforts. Many renewable resources are already cost-effective, particularly when distributed savings and other readily quantified savings are considered. All cost-effective renewable resources should be acquired with or without green pricing. Green pricing simply provides customers with a mechanism to accelerate renewable development beyond the level that is justified using sound least-cost planning. Creating an additional significant market for these resources can lead to enhanced production techniques that further reduce the cost of these resources.

## Initiative #2: Utility Incentives -- Utility incentives to acquire renewables will focus utility management's attention on cost-effective renewable resources.

The current rate-setting process provides no incentive for a utility to acquire renewable resources. Regulators should consider reasonable incentive mechanisms that encourage utilities to acquire cost-effective renewable resources.

In 1989, utility regulators realized that the financial incentives inherent in the traditional regulatory process was incompatible with least-cost planning principles. That year, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution calling upon regulators to reform regulatory practice so that a utility's successful implementation of its least-cost plan would also be its most profitable course of action.

The theory was simple: get the power of profits to work for sound energy policy instead of against it. A number of states have now implemented specific regulatory reforms aimed at making utility investment in energy efficiency profitable. These efforts represent a welcome change from the highly unprofitable condition that prevailed previously. The impact of these changes in states such as New York, Massachusetts, and Washington have been profound. Utility investment in energy efficiency has increased and internal utility focus and direction has changed for the better.

A 1989 NARUC study concluded that utilities have no incentive to purchase power from cost-effective renewable resources or cogeneration facilities. Under conventional regulation, the cost of power purchased from these resources is passed on to customers and contributes nothing to utility earnings.

Increasing utility knowledge and experience with renewables is not enough. Neither is it sufficient for regulators to increase the pressure on utilities to improve planning methods to incorporate renewables. Integrating renewable resources into the fuel mix of existing utilities is greatly complicated by the fact that many electric utilities simply do not want these facilities. NUG developers frequently report that even in states where non-utility generation have been demonstrated to be reliable and cost effective, there is resistance from the utilities.

This antipathy is, to some extent, understandable. The business relationship between buyers and sellers of non-utility generation is considered by many utilities to be an artificial relationship imposed entirely by legislation and regulatory intervention. Regardless of whether the regulatory device for purchasing non-utility generation has required the use of "standard contracts" or has relied upon competitive bidding, both approaches, in essence, are viewed as coercing utilities into a business relationship that would not otherwise exist.

A realignment of this relationship, toward a model in which utilities will have an internal instead of external reason to acquire renewables, can indirectly remove many of the barriers described earlier in this paper.

In the long term, as power purchases become a larger portion of the utility industry's total resources, new regulatory approaches may be needed to change utility indifference or resistance to the purchase of power from renewable resources. In the short-term, utility inertia and, in some cases, outright resistance toward purchasing power from non-utility sources need to be countered.

A simple, short-term solution is to adopt modest supply-side incentives for utility acquisition of renewable resources. Incentives for renewable energy have historically been targeted at the suppliers of power. Attractive federal investment and energy tax credits and additional state tax benefits were used in the late 70s and 80s to spur capital investment in renewable energy resources. These investment tax credits amounted to ten to almost 40 percent of the installed cost of the plants. In the 90s, incentives for investment in plants (which may or may not operate) have been replaced with incentives that are production-based. Congress is now in the final days of adopting a production credit equal to 1.5 cents per kWh for energy produced from new renewable resources. Unlike investment credits, production credits can only be earned if plants are constructed and operating.

**Utilities have no incentive to purchase power from cost-effective renewable resources or cogeneration facilities.**

Targeting incentives at developers of renewable resources is useful particularly if the renewable resources are not yet competitive with conventional resources, or if conventional

In May 1993 the Wisconsin PSC approved the nation's first incentive for utility acquisition of renewables. The incentives are:

·75 cents per kWh for wind, photovoltaics and solar thermal, and

·25 cents per kWh for biomass and MSW

resources appear artificially inexpensive due to tax or other subsidies. If, on the other hand, renewables are already cost effective, and many are, tax subsidies or other incentives may not accomplish as much as expected.

While the move to production incentives and away from investment credits is a sound idea, the proposed incentives are targeted exclusively at non-utility developers. No portion of any incentive for renewables has been targeted at the utility which establishes the business relationship with -- and purchases the output from -- the developer of the renewable-based projects.

A modest incentive aimed at the utility purchaser can accomplish more than a much larger incentive paid to the developers. Many energy efficiency resources are very low cost, much less expensive than new supply-side resources, yet utilities have had very little interest in acquiring the resource. Tax incentives for energy efficiency which further lowered the cost of energy efficiency, while welcomed by efficiency advocates and suppliers, still would not have induced utilities to invest in energy efficiency.

Today, many utilities have dramatically increased investment in energy efficiency. The reason is straightforward -- regulators and energy efficiency advocates made cost-effective investment by utilities in energy efficiency a profitable endeavor.

Over twenty states have adopted regulatory reforms under which utility investment in energy efficiency is cost effective. The approaches vary from state to state, but the end result is the same.[15]

So why is it that no state yet allows utilities to earn even a penny on cost-effective purchases of renewable energy?

While there are, no doubt, many approaches that can be tried, one especially attractive and simple option is to allow utilities that purchase power from renewable resources to earn one mil per kWh for each kWh purchased, provided that the purchase price is at least one mil per kWh less than the utility's avoided cost.

This suggested one mil incentive is modest compared to the 15 mil production credit existing federal tax laws provide to non-utility developers of renewables. Yet, given the many existing barriers to utilities purchasing renewables, it is very likely that the one mil directed at the utility will yield more renewable development than 15 mils or more directed at the renewable developers.

Whether the barrier is utility inexperience with renewables, avoided cost methods that fail to identify the value of renewables, or burdensome contract terms, a modest utility incentive will give utility managers a clear and direct reason to overcome obstacles.

**Green RFP**

**Initiative#3: Green RFPs -- Carefully construct requests for proposals and other utility programs to help renewable developers reduce transaction costs and match promising renewable resources with utility needs.**

Regulators should encourage utilities to experiment with green RFPs and competitive bidding solicitations limited to renewable resources.

For the first decade of PURPA, the market for power from QF and renewable generating resources was based on avoided costs calculated by utilities or regulatory agencies. More recently, twenty-eight states have adopted competitive bidding as an alternative means to both establish market-based avoided costs and select new generating capacity.

The success of competitive bidding schemes and their impact on QFs and renewable resources is entirely dependent upon how bidding systems are set up and administered.

Problems arise in three areas. First, in most bidding systems, renewables must compete for new resource additions with the QFs, independent power producers (IPPs), as well as conventional utility resources. Because utilities are already familiar with conventional technologies and because most bids are from traditional technologies, bid documents and procedures are written in terms of these technologies.

Second, regulators and utilities perceive that the primary benefit of competitive bidding is the reduction of the price paid for power rather than the value of the power being offered. Consequently, competitive bidding tends to place undue emphasis on price terms and, in particular, on price in the near term. Non-price variables such as diversity and fuel price risk are often given little weight.

| UTILITY INCENTIVE |
|---|
| Allowing a utility to earn one mil per kWh for each kWh of energy purchased from a new renewable resource, provided that the purchase price is at least one mil below the utility's avoided cost, can overcome many barriers. |

Competitive bidding is also occasionally viewed as a substitute for more detailed utility planning and avoided cost analysis. This is unfortunate because the economic value of many renewables becomes apparent only when detailed analysis is performed. For example, a 10-cent per kWh bid from a strategically situated renewable resource may provide more value to the utility than a 5 cent per kwh bid from a coal-fired power plant.

On the positive side of competitive bidding, a utility's request for proposals (RFP) can provide renewable resource developers with a wealth of information about the utility's needs and the characteristics of its service territory. Carefully constructed competitive solicitations can be designed to avoid both the problems that discourage participation by renewable developers and bias against those renewables that do participate.

**Green RFPs can serve many purposes.**

A green RFP is a separate utility solicitation for new resources issued exclusively to renewable resource developers. A green RFP is an effective means of combining the cost control aspects of competitive bidding with an RFP's capability to provide needed information and encouragement to developers of renewable resources. By issuing separate solicitations for renewables and non-renewable resources, the bidding documents and evaluation procedures can focus on the special characteristics of renewables.

In the simplest case, a green RFP can help identify renewable resources that are already commercially available and cost effective, such as hydro-electric, biomass, wind, and, in some areas, geothermal and solar thermal facilities. Developers of these resources may not participate in open-ended, supply-side competitive bid solicitations because of high transaction costs and experience suggesting that bidding systems are biased against renewables. A green RFP, on the other hand, serves as an invitation to renewable resource developers. The mere fact that the RFP is limited to renewable resources tells developers of renewable resources that factors other than the simple price per kWh are important.

Renewable resources such as wind and PV may be especially cost effective when constructed in special locations. The limited scope of a green RFP may lend itself to focus on these opportunities more than do conventional RFPs.

A separate green RFP also meshes well with the green pricing initiative described earlier. The utility's obligation under green pricing is to acquire the renewable resources "demanded" by customers opting for the premium service and to acquire these resources in a cost-effective manner. These obligations are easily satisfied by a green RFP.

Green RFPs can also serve as a training and education tool. Electric utility planners and engineers may lack experience with the performance and potential applications of renewable technologies. A green RFP can be used to identify and select qualified manufacturers, vendors, and contractors to work with electric utility personnel to fill this need.

Finally, a green RFP could be used in conjunction with an electric utility's research and development efforts. Some renewable technologies and applications are not yet cost effective. As part of an R&D program a green RFP would be useful in enhancing a utility's understanding of renewable technologies, testing and improving the cost and operating characteristics of the promising technologies, and identifying new ways to integrate them into conventional electric utility applications.

Whether the purpose of the green RFP is to secure new supply resources, to transfer technology and education, or is simply an R&D activity, a green RFP will stimulate renewable resources' opportunities while assuring regulators that dollars devoted to renewables are well spent.

New England Electric System (NEES) has recently completed its first Green RFP. The final results are impressive and has convinced NEES that the cost and availability of renewables are much better than originally thought.[16] California regulators have also recently ordered utilities to issue renewable RFPs for a designated portion of the state's new generating capacity.[17]

**Utility Assistance Program**

In addition to green RFPs, utilities should adopt a systematic series of measures designed to attract and assist developers of renewable resources.

Developing power supply projects is difficult regardless of whether the developer is an electric utility or a NUG. With respect to the development of renewables other than hydro-electric projects, utility development is handicapped by a lack of experience with the technologies. (Some utilities are also handicapped by broader efforts to remove them from the business of adding new generation.) On the other hand, non-utility developers of renewable resources are less likely than the local utility to have information about local resource availability (the location of sites and steam hosts in the case of cogeneration facilities), local and state permit requirements and processes, and environmentally or politically sensitive areas.

Attracting renewable projects to a state where they are not already actively involved is not easy. There are many reasons. Developers tend to focus their efforts on states with abundant and low-cost renewable resources and relatively high purchase power rates. The availability of wind, solar, or other resources are clearly matters beyond the control of utilities or regulators and therefore there is nothing they can do to the natural resource to attract potential developers. The level of purchase power rates cannot be set arbitrarily high.

Other factors, however, can greatly influence the level of interest of renewable developers. Receptive electric utilities, supportive utility regulation, and efficient siting and licensing processes all can make a big difference in attracting renewable projects.

In particular, a deliberate and systematic utility-sponsored renewable assistance program can be designed to encourage the development of renewable resources. By virtue of their extensive customer contacts and familiarity with their service territories, local electric utilities can be a valuable source of information about resource availability, potential sites, and local transmission and distribution problem areas. Electric utilities are also large land owners, holding rights-of-way and other properties that might be useful to renewable resource developers. For very small renewable resources located on customer premises, utilities might also provide a clearinghouse service to match vendors with willing hosts.

Utility assistance efforts should extend to matters that can reduce renewable resource development and transaction costs. Joint venture financing tools or other methods of reducing the cost of capital for renewable projects, and innovative ways to reduce the high cost of insurance for small facilities are examples of steps that might be taken.

Power contracts normally require that developers maintain general liability insurance and that the electric utility be a named insurer. Due to the small number of insurers providing coverage for power generation facilities (and the lack of stiff pricing competition), the minimum insurance premium levels are quite high. A typical minimum level insurance policy costs between $4,000 and $5,000 per year.

Table 3 illustrates the impact of this type of insurance requirement on different sized facilities.

**Table 3: Insurance Costs**

| | **PV<br>10 KW** | **Wind Turbine<br>200 KW** |
|---|---|---|
| Annual insurance cost | $5,000 | $5,000 |
| Annual energy production, kWh | 26,000 | 613,000 |
| Insurance cost cents/kWh | 19 | .8 |

The high unit cost of insurance is a clear impediment to small facilities. One solution might be for the electric utility to obtain a blanket ("group") insurance policy covering a large number of facilities and bill the cost of the service back to suppliers on a pro-rata basis. That would effectively reduce the insurance costs for small facilities.

## Initiative #4: Safe Harbor -- State regulators should develop safe harbors which reduce utility uncertainty with respect to renewable resources.

**Safe Harbor Rules**

Regulators should create a "safe harbor" for utility research, development, and demonstration of renewable energy resources.

Such rules could set permissible boundaries, or a safe harbor, within which utility experimentation would be encouraged by reducing risk and assuring full cost recovery for well-conceived and well-managed pilot projects, even if they prove to be not cost effective.

Greater electric utility use of renewable resources, particularly the newer technologies not yet proven in utility applications or too expensive because of low production levels, is impeded by risks that the costs associated with these types of activities will not be recovered. New technologies (or new applications of known technologies) are never without risk. The question is, who -- between consumers or utility shareholders -- will bear the risk of research and development. The more risk placed on utilities, the less likely utilities will experiment with renewables. The perceived risks include:

- <u>Technical risk</u>: will the new generator come on-line at its anticipated capacity rating?

- <u>Cost risk</u>: will the new generation technology cost significantly more to construct or operate than anticipated?

- <u>Lifetime risk</u>: will the new generator's life-time be shorter than anticipated due either to technical problems or as the result of unanticipated regulatory decision?

- <u>On-time completion risk</u>: will the technology not come on-line when anticipated because of technical or regulatory problems?

- <u>Reliability and performance risk</u>: will the technology be significantly less reliable than planned?

Utility uncertainty can be reduced through regulatory rules which encourage the use of demonstration programs for renewable resources. Safe harbor rules also give regulators an effective means of expressing policies and preferences relating to renewable R&D activities, as well as establishing R&D expenditure budget levels that protect customer interests. Safe harbor rules might also specify permissible types of projects and the maximum duration of the program.

Safe harbor rules have been used to encourage similar experience-gathering R&D activities relating to the design and implementation of energy conservation programs. The state of Maine, for example, encouraged experimentation and R&D for demand-side resources by adopting rules that assured cost recovery for well-designed pilot programs, even when programs proved not cost effective. Applying the same principles to renewable resources will reduce utility risk, thereby encouraging the development of renewable resource pilot prototypes.

Appendix B provides a more complete discussion of the safe harbor concept, including a simple model Rule for commissions to consider.

## Initiative #5 Stand-alone Service -- Adopt rules that encourage the use of cost-effective renewable-based customer stand-alone service.

Regulators and utilities should adopt service and pricing options for non-connected, off-grid customers to assure that cost-effective renewable resource alternatives for these customers are fully considered.

As the cost of modular renewable power technologies continues to decline, the extension of utility distribution lines to new off-grid loads warrants more careful analysis. Likewise, the small, dispersed renewables might be a cost-effective alternative to the replacement or upgrading of existing lines to small, remote, or hard-to-serve customers.

For extension of electric service to unserved areas, avoided costs are the sum of capacity and energy-related savings at the power generating level, plus the labor and materials cost of placing poles and transformers, added to any transmission and distribution costs caused by the extension of the system. These total costs of extending service in a conventional manner should be compared with the costs of stand-alone, renewable systems which provide equivalent service.

In some states a sizable number of remotely located residential customers already use stand-alone systems. In 1990, PG&E surveyed remote residential customers in California and found that about 3,500 stand-alone PV systems were in use at the end of 1989. At that time the utility estimated that the residential market for stand-alone PV systems was growing at about thirty percent each year.

In Colorado, K.C. Electric, a rural cooperative within the Western Area Power Administration, has piloted a successful application of PV for powering livestock watering pumps. These loads were previously quite expensive to serve because they were small, remote from electric lines, and subject to high weather-related maintenance costs.

What steps can be taken to assure that low cost service options are pursued?

## Line Extension Rules

The Colorado PUC was the first commission to amend its electric line extension rules to require utilities to present potential customers with a cost comparison between stand-alone photovoltaic systems and conventional line extensions. Applicants for service provide the utility with an estimate of their monthly energy use. If the ratio of monthly customer consumption (in kWhs) to the required extension line distance (in miles) is 1,000 or less, the utility is required to provide a cost comparison of the two options. For example, a customer with an estimated energy requirement of 500 kWhs per month (about average for Colorado) and living a half mile from existing distribution lines would be a candidate for a stand-alone PV system (500/.5=1000).

Whether or not the Colorado rule has led to renewables being chosen over line extensions, it has clearly led to Public Service Company of Colorado becoming familiar with PV systems, and has resulted in the training of utility personnel in the specifications of PV systems.

This valuable experience, gained as a direct result of the PUC rule, should lead to greater use of PV systems in and around the utility's system.

Unfortunately, this service option has not received more widespread utility attention. Lack of information about the alternatives, lack of training in the comparative analysis, and lack of supplier relationships with providers of stand-alone renewable systems are some of the reasons.

But, even if utilities provide comparative cost information, the lack of customer familiarity with (and confidence in) the technologies can represent a serious impediment to renewable deployment. New approaches to sharing information or reducing the risks of service reliability and system maintenance expense can overcome these impediments.

A number of workable risk allocation arrangements between utilities and customers are possible. Each of these alternatives appeal differently to customers and utilities. Whatever approach is used, it should be consistent with existing policies regarding customer contribution costs.

### Option 1: System Ownership by the Utility

At one end of the spectrum of possibilities, the utility could be the owner and operator of the stand-alone system. This option provides maximum convenience and benefit for the customer. The risk of system reliability is shared. The utility bears the risk that future costs might be incurred to maintain service reliability. The customer bears only the residual service quality risk.

Under this option the utility would analyze the cost effectiveness of a stand-alone system by comparing the total cost of the system to the total generation, transmission and distribution costs of conventional service. If the stand-alone system proves cost effective, the utility would initially bear the full installation cost of the stand-alone system, minus a customer contribution which would be the lesser of 1) the cost of the stand-alone system, or 2) the utility's ordinary charge for a conventional line extension, minus any utility savings owing to the stand-alone system.  The utility would also bear the system's maintenance and replacement costs, just as it would bear maintenance and replacement costs for the line extension alternative.  The utility would recover its costs through the ordinary rate-setting process.  The individual customer receiving energy from the stand-alone system would be charged the normal, tariffed electricity rates.

The stand-alone system's capital cost, less the customer contribution, would be included in the utility's rate base and would earn the utility's authorized rate of return in exactly the same manner as would have occurred for a conventional line extension.  Installation and maintenance expenses would be recovered through rates in the same fashion as other operating expenses.

Table 2 compares the total cost of an ordinary line extension to the cost of a stand-alone system.  In the case of an ordinary line extension, the illustration assumes that the customer would receive a subsidy for the construction of the distribution line and is charged the normal tariffed price for electricity instead of the full incremental cost of capacity and energy.

**Table 2:  Illustrative Comparison of Cost of Service to New Customers**

| | **Line Extension** | **Stand-Alone System** |
|---|---|---|
| Total Cost of Extension or SAS | $20,000 | $25,000 |
| System Savings<br>(capacity, energy & line losses) | 0 | $8,000 |
| Utility Subsidy<br>(300 feet) | $5,000 | $5,000 |
| Added DSM Cost | 0 | $1,000 |
| Customer Contribution<br>(Line 1-2-3+4=Line 5) | $15,000 | $13,000 |
| Electricity Price<br>(Cents/kWh) | .10 | .10 |

In the line extension case, the stand-alone system takes the place of both the line construction and the conventional power plant construction and operation.  The example also assumes that the stand-alone case includes substantial incremental investment in energy efficiency measures.

The customer is assumed to pay for the cost of the line extension or the cost of the stand-alone system, less the standard utility subsidy.  In the stand-alone case, the customer also pays for the added cost of the energy efficiency measures and receives from the utility the system capacity and energy savings resulting from the installation of the stand-alone system.

As shown in Table 2, the customer would enjoy all the cost savings through lower hook-up costs, but would otherwise pay the same rate as ordinary customers.

**Option 2: Utility Analysis and Financing**

This option represents the middle ground between full utility ownership on the one hand and no utility participation on the other. Under this option, the utility provides the customer with an engineering and economic analysis of a stand-alone system. Assuming the stand-alone system is cost-effective, the customer has a choice of a grid connection at a higher cost or the purchase of a stand-alone renewable system at a lower cost. As an alternative to outright customer purchase, the utility could either lease the equipment to the customer or provide financing and recover its cost via a monthly utility bill. Under this arrangement, the utility provides technical and financial services but does not provide or sell the actual electricity.

The utility could use its own personnel to provide engineering and installation services or, alternatively, opt to subcontract with private firms already in the market. In either case utility personnel would provide quality control services. Similar partnerships between utilities and private vendors are now commonplace with respect to the delivery of energy efficiency programs.

**Option 3: Utility Analysis with Customer Purchase**

A third possibility reduces the role of the utility to information provider. This option would likely lead to the lowest level of customer interest in stand-alone systems. Under this option, the utility conducts an economic analysis and provides the information to the customer along with a listing of acceptable service providers. The customer would choose a system, get it installed, and pay for it. The customer gets maximum choice and receives all, if any, savings while the utility reduces its potential maintenance and replacement costs.

**Utility Applications for Stand-Alone Renewables**

Electric Power Research Institute (EPRI) has identified sixty-five applications of currently cost-effective utility in-house uses of photovoltaic technology. Of these, three applications -- gas flow computers, water level sensors, and automated gas meters -- seem to hold the most promise.[(18)]

By the end of 1989, PG&E was operating more than 420 PV installations. Planned 1990 PV installations increased the number to more than 700. PG&E, however, seems to be the exception. In other utilities, with rare exceptions, equivalent cost-effective PV opportunities have not been pursued.

A conservative estimate made by EPRI suggests that utility in-house applications could add an extra annual five to ten megawatts of PV to current world-wide PV capacity of about 50 MW. This additional 10 to 20 percent increase in market demand could encourage further economies of scale in manufacturing and help lower PV costs by inducing investment in new, more efficient PV manufacturing technology.

NARUC, in conjunction with the Department of Energy, has produced a handbook for regulators and utilities describing the cost-effective applications for PV systems.

There are other simple and practical steps regulators can take to ensure that utilities take full advantage of cost-effective PV and other renewable systems. For example, regulators might require utilities to provide PV vendors with an inventory of potential applications for PV systems. This report would be updated periodically with the addition of new sites requiring remote power and the expected replacement of systems at existing sites. Similar reporting requirements could be applied to telephone, water, and gas utilities.

## Initiative #5: Tax Reform -- The restructuring of taxes currently imposed on utilities would make renewable resources more attractive to utilities.

Converting existing utility taxes on a revenue neutral basis to an emission tax could provide a simple way to begin internalizing social costs without necessarily increasing the cost of electricity.

Efforts to incorporate environmental externalities in electric utility resource planning and acquisitions meet with stiff resistance from utilities, some consumer groups, and some federal and state governments. The basis for opposition varies, but major concerns include: 1) the imposition of new and incremental costs or taxes on consumers, 2) the risk of unintentional misallocation of resources and possible increases in emissions if externalities are applied solely to electric utilities and not to other energy or electricity suppliers, 3) uncertainty regarding the values to be assigned to environmental emissions, and 4) the possible lack of legal authority of public utility commissions to consider environmental or other externalities.

Debates over these issues are and will continue to take place in many states and in many forums. One practical alternative which circumvents some of the major concerns is to convert existing electric utility sales taxes or gross receipt taxes to emission taxes.

State treasuries now collect about five percent of total electric utility revenues, or about $8 billion per year, through sales, gross receipts, or other similar taxes. Another $3 billion is collected by local governments in the form of property taxes assessed on utility facilities, while $1 billion is collected through state income taxes. The federal governments takes $7 billion, mostly though corporate income taxes.(19)

These state, local, and federal government taxes raise electricity prices but exert no meaningful influence over utility resource planning or operational decision making. There is no action that a utility can take to profit or lose from changes in sales tax obligations. Sales taxes are unaffected by the type of resource used to produce electricity.

If sales taxes were replaced, on a revenue neutral basis, by emission taxes, utility operations and resource acquisition decisions would be influenced. The addition of pollution control equipment to existing plants, the substitution of cleaner burning fuels, and alterations to the order in which power plants are dispatched would reduce a utility's air pollution emissions and hence its tax costs. Pollution reduction measures would be taken whenever the added cost of buying cleaner fuel or adding pollution control equipment was less than the cost of the emission tax. Similarly, the presence of emission taxes would influence the selection of new capacity additions. Renewable resources with little or no associated air pollution would yield a significant tax benefit as compared to fossil-fueled technologies. In economic terms, utilities would be motivated to reduce emissions whenever the tax savings from increased control exceed the cost of control, or the incremental cost of cleaner but more expensive resources.

Table 4 illustrates the potential effect of substituting a pollution tax equal to an existing five percent sales tax. The pollution taxes were calculated using data for a major East Coast investor-owned utility with an existing state tax obligation of about $100 million. The total tax obligation of $100 million was allocated over $SO_2$, $NO_x$, and $CO_2$ in approximate proportion to one estimate of environmental impact. The same five percent tax could be spread over these or other pollutants in different ways or it could be allocated entirely to $CO_2$, the only air emission that is not currently regulated.

The taxes for a hypothetical utility are expressed in dollars per ton of 1990 emissions, the equivalent tax expressed in cents per kWh for a variety of existing and new resources.

**Table 4: Illustration of Emission Tax Effects**

| | **$CO_2$** | **$SO_2$** | **$NO_x$** |
|---|---|---|---|
| Tax obligation ($ millions) | 24 | 67 | 10 |
| 1990 emissions (tons) | 15.2 | .14 | .063 |
| Tax rate $/ton | $1.58 | $476 | $159 |

| **Power source** | **$CO_2$ cents/kWh** | **$SO_2$ cents/kWh** | **$NO_x$ cents/kWh** | **Total** |
|---|---|---|---|---|
| Existing Coal plant (high sulphur) | .16 | .8 | .07 | 1.03 |
| Existing Coal Plant (low sulphur) | .16 | .4 | .07 | .63 |
| New Gas Turbine | .08 | 0 | .002 | .082 |
| Oil (high sulphur) | .14 | .8 | .04 | .98 |
| Oil (low sulphur) | .14 | .4 | .04 | .58 |

Table 4 leads to several conclusions. First, the tax savings associated with displacing existing fossil-fueled resources is significant. For an existing conventional coal-fired facility, the tax per kilowatt-hour is about 1.0 cent. Restructuring the way taxes are collected from utilities would permit utilities to pay up to 1.0 cent/kWh more for non-polluting renewable resources than they would have without the restructuring and without any net increase in the cost to consumers.

The potential tax savings are also large enough to change the fuels utilities use to generate electricity and the sequencing, or dispatching, of different power plants. Currently, the difference between the cost of high sulfur and low sulfur coal is about .2 cents per kWh. This cost difference is less than the tax savings utilities would realize upon changing to the cleaner-burning fuel. Likewise, the difference between the cost of natural gas and coal is currently about .3 cents per kWh. This cost difference is also smaller than the tax savings resulting from reduced $SO_2$, $CO_2$, and $NO_x$ emissions.

The precise impact on the use of new and existing resources depends on the relative cost of different fuels and to a lesser extent on the allocation of the total tax burden between the various pollutants. Placing more of the tax on $CO_2$ will increase the shift to natural gas, thereby decreasing the emission of both $CO_2$ and $SO_2$. Increasing tax rates on $SO_2$ and decreasing the tax rate for $CO_2$ will cause increased use of pollution control devices and lower sulfur fuels and relatively less use of natural gas.

As with any proposal that would substitute emission taxes for existing sales taxes and gross receipt taxes, there are pluses and minuses.

On the plus side there are five items:

1) Adopting emission taxes, even if initially only for electric utilities, establishes a policy and legislative framework which can be applied to other energy sectors. Current practices of using estimated environmental costs at public utility commissions provides no opportunity to apply the same principles to on-site generation of electricity or to transportation fuels, heating and industrial boiler fuels, or to other energy sources not regulated by the public utility commissions.

**Adopting emission taxes, even if initially only for electric utilities, establishes a policy and legislative framework which can be applied to other energy sectors.**

2) Although PUCs may lack the legal authority to consider environmental or other social costs, emission taxes are clearly within the authority of state legislative bodies.

3) Even where state utility regulators are considering environmental costs, most states limit consideration to choices between competing new power supplies. Emissions from existing power plants, which are many times higher than emissions from new power plants, are

ignored. (One exception, California, had previously considered emissions from both new and existing resources, but recent legislation substantially cut back on the extent to which emissions from existing facilities could be used to justify the addition of new resources.)

4) Revenue-neutral emission taxes lessen the controversy over the level of environmental costs to be used. As the term implies, revenue-neutral emission taxes are designed to collect a fixed amount of money. How the emission taxes are divided between various pollutants remains an issue, but the overall tax level is relatively fixed. Any future increase or decrease in the emission tax will be informed by scientific study and debate over the cost of pollution, much like the debates on alcohol and tobacco are informed by new information on the impact of these products on health costs.

5) New taxes are never popular. Revenue-neutral tax changes and so-called sin taxes and pollution fees are more widely accepted by the public than other forms of taxes.

As promising as this initiative appears, it does not solve all problems; indeed a few new ones are created:

1) As social costs go down (as a result of internalizing environmental costs), direct costs of energy may still go up. Assuming overall government tax revenues are constant, reduced revenues resulting from industry's efforts to reduce pollution will result in higher taxes somewhere in the economy.

2) To assure revenue neutrality, the emission tax might be established only after some effort to estimate the utilities' short-term response. For example, if the emission taxes shown in Table 4 were initially established, researchers would quantify the amount of pollution reduction that would occur through the use of cleaner fuels. If the utility response were to incur an additional $25 million of cost due to the use of cleaner fuels, an initial tax rate that correctly anticipated the amount of pollution reduction, the total cost to electricity consumers would be the sum of its original $100 million tax bill plus the $25 million higher fuel cost. (Several iterations may be required.)

3) As with any change in taxes, there will be winners and losers. A state with several electric utilities could devise emission taxes that were revenue neutral on a statewide basis, but different utilities' fuel mixes would make it unlikely that any set of emission taxes would be neutral to each utility.

On balance, experimentation with revenue-neutral emission taxes should be encouraged. Environmental advocates, utilities, and regulators who wish to approach environmental externalities in ways that are most amenable to broad-based applications of new and existing energy sources could form a coalition strong enough to adopt the necessary state legislation.

## Initiative #7: Federal Support -- The Federal Energy Regulatory Commission should begin taking action to encourage the development of renewable resources.

**Transmission**

Other than the issuance of regulations more than a decade ago, the FERC has had little direct involvement with the state implementation of PURPA or the development and implementation of least-cost planning. In 1988, the FERC revisited the topic when it issued several Notices of Proposed Rulemakings (NOPRs) aimed at amending the original PURPA avoided cost rules, encouraging competitive bidding and allowing IPPs to be governed by the same rules as qualifying facilities.

These NOPRs were eventually abandoned after facing a variety of criticisms from state regulators, utilities, and others. Some of the criticisms were aimed at the FERC's overly simplistic approach to both avoided cost determinations and competitive bidding. The FERC's NOPRs contained (and would have perpetuated) many of the commonly misunderstood aspects of these issues discussed earlier. As a general matter, transmission is the only area where the FERC's jurisdiction is currently so pervasive and preemptive of state action that FERC initiatives could be helpful.

Unlike power plants fueled by coal, oil, gas, and uranium, electricity produced from renewable resources such as hydro, wind, solar, thermal, and to a lesser extent biomass and PV must be produced where the resource is located and either used on site or transmitted to other areas. Special transmission rules for renewable resources would encourage the development of renewable resources in areas with little demand for electricity but with abundant renewable resources.

Special rules could take several different forms.

1) To minimize transaction costs for transmission service for small facilities, the FERC should require utilities to file standard wheeling tariffs for service from renewable resources. Standard wheeling tariffs are not now required. As a result, if power is not purchased by the local utility, the renewable resources developer must negotiate wheeling arrangements and must do so for each utility territory crossed. This can present a significant barrier, particularly for very small facilities.

2) If transmission line capacity is a limiting factor for sales of power from one area to another, the FERC could adopt rules that require electric utilities to give preference to wheeling power from renewables. Currently, utility wheeling is voluntary and each utility establishes its own rules for access to the transmission grid. If enough transmission capacity is not available to serve all power projects desiring wheeling service, the wheeling utility decides what service to provide. Any facility without long-term firm transmission service will not be developed.

3) FERC could consider the environmental costs associated with alternative uses for transmission facilities. For example, bulk power transactions which result in reduced regional emission might be given priority access or lower prices compared to transmission services that increase regional emissions.

## CONCLUSION

Simple and achievable improvements in electric utility and state regulatory practices offer enormous opportunities to increase the use of renewable resources for the production of electricity. Most of these opportunities involve the expanded use of renewables that are already cost-effective but suffer because current planning and resource evaluation methods fail to measure the actual value of these resources.

The greatest barriers to renewables can be overcome with better communication, improved analytical approaches, and education about the problems and available solutions. Barriers can either be addressed directly or indirectly. Thus, new initiatives such as green pricing or incentives for utility purchases of renewable resources may be more effective at removing barriers than a direct attack on perceived problems.

One thing is clear -- renewable energy can play a much larger role in the nation's electricity supply than it does. Aggressive and creative actions by regulators, utilities, and other policy makers can make an enormous difference.

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1. From a utility and regulatory perspective, barriers to renewable technologies which do not generate electricity, such as solar water heating, day lighting, and passive or active solar design are similar to the impediments to increased investment in energy efficiency. These technologies are therefore not included in this paper.

2. Sustained orderly development is a concept developed by California's Coalition for Energy Efficiency and Renewable Technologies, a coalition of renewable energy companies, environmental organizations and public interest groups. Aitken, Donald W. "Sustained Orderly Development of the Solar Electric Technologies," Solar Today, May/June 1992.

3. This report is entitled "America's Energy Choices: Investing in a Strong Economy and a Clean Environment." It is referred to as simply the Alternative National Energy Strategy.

4. Renewable Energy And Utility Regulation, Moskovitz and Laporta, 1991. (NARUC)

5. The 12 states studied were New Mexico, Wisconsin, Colorado, Arizona, Washington, Georgia, Iowa, Virginia, New Jersey, Texas and Rhode Island. A summary of state information is available as Appendix A to the original report.

6. North American Electric Reliability Council (NERC), "1990 Electricity Supply & Demand for 1990-1999," Sept. 1990: New Jersey.

7. Committee on Energy Conservation, ed. David Moskovitz, Carlo La Porta, "Renewable

Energy and Utility Regulation," National Association of Regulatory Utility Commissioners (NARUC), February, 1991: Washington, D.C.

8. "ABB Methodology used to Forecast Peak Load, Energy, and Demand-side Management Potential for the Central Maine Power Company Transmission Regions," ABB Power Systems Inc., August, 1991: Pittsburgh, PA.

9. Edison Electric Institute (EEI), "1990 Statistical Yearbook," 1991: Washington, D.C.

10. Before the Public Utilities Commission of the State of California, Docket No. I.90-09-050.

11. Awerbuch, Shimon, "The Role of Risk and Discount Rates in Utility Integrated Resource Planning," July 1991: Lowell, MA.

12. EPRI, Capital Budgeting for Utilities: The Revenue Requirement Method. EA-4879, October 1986: Palo Alto, CA.

13. Crousillat, Enrique, Spiros Martzoukos, "Decision Making Under Uncertainty -- An Option Valuation Approach to Power Planning," Industry and Energy Department Working Paper Energy Series Paper No. 39, The World Bank, August, 1991: Washington, D.C.

14. Ibid. p. i.

15. See **Profits & Progress** for a description of various incentive options. See "Regulatory Incentives for Demand-side Management, (edited by Nadel, Reid, Wolcott, published by ACEEE, 1992: Berkeley, CA) for a summary of current state actions.

16. Personal communication with Richard Sergal, June, 1992.

17. Before the Public Utilities Commission of the State of California, "Interim Opinion, Resource Plan Phase: Bidding for New Generation Resources," April 22, 1992, Docket No. I.89-07-004.

18. Electric Power Research Institute (EPRI), "On-site Utility Applications for Photovoltaics, EPRI Journal, March 1991: Palo Alto, CA.

EPRI, Cost-effective Photovoltaic Applications for Utilities and Their Customers, 1991, Palo Alto, CA.

19. Ibid.