Chapter 10

# Federal Policy Options

# CONTENTS



## List of Tables



## List of Figures

# Chapter 10
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## OVERVIEW

Over the last several years, the need to diversify the electricity generation mix has become increasingly clear, part of the strategy for meeting this policy objective has been sustained development of new electric generating technologies. With considerable uncertainty in load growth as well as other major policies affecting utility and nonutility decisions about new and existing power generating capacity, the attainment of a diverse generation mix has taken on added dimensions. Because of this uncertainty, it may be prudent to accelerate the availability of the technologies discussed in this study so that they could make a greater contribution in the 1990s than currently is expected.

Seeking diversity in electricity supply options is now not only being pursued to reduce dependence on oil but also in anticipation of the variety of future circumstances as discussed in the chapter 3, such as more stringent control of air pollution emissions or increased availability of natural gas. Developing technologies are of interest in the short term since they might contribute to ensuring a reliable and economic supply of electricity over the next two decades under a variety of these future circumstances. Many of these technologies also offer promise of fuel flexibility, increased efficiency, and other advantages. An increased contribution before the turn of the century, however, will require accelerated development of these new generating technologies, including progress in a number of critical areas. This is because at *the current rate of development* very few of the technologies considered in this assessment are likely to be deployed *extensively* in the 1990s,

This chapter discusses a range of alternative policy initiatives that could accelerate the commercial deployment of developing generating and storage technologies in the 1990s, The goals and options are summarized in table 10-1. The first three:

**Table 10-1 .—Policy Goals and Options**

***Reduce capital cost, improve peformance, and resolve uncertainty:***
1. Increase Federal support of technology demonstration
2. Shorten project lead times and direct R&D to near-term commercial potential
3. Increase assistance to vendors marketing developing technologies in foreign countries
4. Increase resource assessment efforts for renewable energy and CAES resources (wind, solar, geothermal, and CAES-geology)
5. Improve collection, distribution, and analysis of information

***Encourage nonutility role in commercializing developing technologies:***
1. Continue favorable tax policy
2. Improve nonutility access to transmission capacity
3, Develop clearly defined avoided energy cost calculations under PURPA
4. Standardize interconnection requirements

***Encourage increased utiiity involvement in developing technologies:***
1. Increase utility and public utility commission support of research, development, and demonstration activities
2. Strengthen provisions for utility subsidiaries involved in new technology development
3. Resolve siting and permitting questions for developing technologies
4. Other legislative initiatives: PIFUA, PURPA, and deregulation

***Resolve concerns regarding impact of decentralized generating sources on power system operation:***
1. Increase research on impacts at varying levels of penetration
2. Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

SOURCE Office of Technology Assessment

A. Reduce capital cost, improve performance, and resolve uncertainty,
B. Encourage nonutility role in commercializing developing technologies, and
C. Encourage increased utility involvement in developing technologies,

are the primary goals; while the fourth:

D. Resolve concerns regarding the impact of decentralized generating sources (and load management) on power system operation,

is less critical although still important.

# GOAL A: REDUCE CAPITAL COST, IMPROVE PERFORMANCE, AND RESOLVE UNCERTAINTY

As discussed in chapters 4 and 8, the current cost and performance characteristics (including uncertainty) of developing generating and storage technologies considered in this assessment generally do not yet compare favorably with either conventional generating options or other strategic options such as load management and life extension of existing powerplants. Of particular concern is the uncertainty in cost and performance anticipated in early commercial utility applications. Even in the case of load management, already being pursued aggressively by many utilities, widespread deployment of load management in the 1990s will depend on continued experimentation by utilities to resolve operational uncertainties; the refinement of load management equipment and techniques including adequate demonstration of communications and load control systems; development of incentive rate structures; and a better understanding of customer acceptance.

The following are alternative policy options aimed at reducing cost, improving performance, and resolving uncertainty in both cost and performance.

**Option Al: Increase Federal support of technology demonstration**

A critical milestone in both utility and nonutility power producer acceptance of new technology is completion of a commercial demonstration program. There is considerable debate in the industry over what constitutes a demonstration program, but usually two basic categories are distinguished. One is a proof-of-concept phase which provides the basic operational data for commercial designs as well as test facilities designed to prove the viability of the technology under non laboratory conditions, and to reduce cost and performance uncertainties. The other involves multiple applications of a more or less mature technology designed to stimulate commercial adoption of the technology. In theory the distinction seems clear; in practice, it sometimes is not. Generally, though, activities in the first category are necessary for demonstrating technical feasibility, and activities in the second category are necessary for demonstrating commercial readiness and for accelerating acceptance by utilities or nonutility power producers.

The length of the appropriate demonstration period will vary considerably by technology, However, adequate demonstration periods (perhaps many years for larger scale technologies) are crucial to promoting investor confidence. Moreover, the nature of the demonstration program—i.e., who is participating, who is responsible for managing it, and the applicability of the program to a wide variety of utility circumstances—is crucial too, if utilities, in particular, are eventually to buy the technology.

Many utility decision makers argue that the perceived and real obstacles to adoption of developing generating technologies can be removed by "well-managed federally sponsored incentives and projects.'[1]" A key ingredient is the nature of the relationship between government and industry in such ventures. A cooperative research and development (R&D) partnership has proven to be a key ingredient in many successful demonstration programs. Demonstration programs should have the following characteristics:

- The private sector should have considerable influence in the selection of technologies for demonstration as well as principal responsibility for demonstration program design and management of the demonstration project itself.
- Private sector proprietary rights and ownership should be preserved, provided that such protection does not inhibit timely development of the technology.
- Cost sharing between government and industry has generally proved successful in ensuring both careful selection of the most

[1] I. R. Straugh n, Director of Research and Development, Southern Cal iforn ia Edison Co., testimony before the House Corn m ittee on Science and Technology, Subcommittee on Energy Development and Applications, June 13, 1984.

competitive projects and timely completion of the projects.

- Federal Government commitments to a demonstration program should be stable and predictable–i.e., once made, such commitments should be honored for a sufficient period in order to convince developers that government is a ''reliable partner. '
- First-of-a-kind, tull-seale demonstration facilities should include support by all partners involved i n the demonstration program for not only plant engineering and construction but also for extended plant operations.[2]

Smaller modular plant designs, where possible, are very attractive for demonstration projects since they normally require a smaller capital commitment than large central station designs. In addition, successful demonstration projects have inCluded active participation from a wide range of private sector interests such as architect-engineering firms, equipment manufacturers, as well as the utilities themselves when appropriate.

### Option A2: Shorten project lead-times and direct R&D to near-term commercial potential

Virtually all of the technologies considered in this assessment offer the potential of sizable deployment in electric power generation applications beyond the turn of the century. *At the current rate of development,* however, few of these technologies are likely to be extensively put in place in the 1990s. Under conditions of accelerated load growth in the 1990s, an increase in or a refocusing of current Federal research, development, and demonstration (RD&D) activities could accelerate the deployment of early commercial units for most of the technologies considered in this assessment. This includes attention not only to the technologies themselves, but also to manufacturing techniques and equipment necessary to produce the technologies.

While the technologies considered here encompass a wide range of sizes, scales, and levels of technological maturity, for purposes of discussing appropriate policy actions, it is convenient to divide them into two basic groups:

- The first consists of technologies envisioned primarily for direct electric utility applications, including integrated gasification/combined-cycle (IGCC) plants, large ( >100 MW) atmospheric fluidized-bed combustors (AFBC), large (> 100 MW) compressed air energy storage (CA ES) facilities, large ( >50 MW) geothermal plants, utility-owned fuel cell powerplants, and solar thermal central receivers.
- The second group consists of technologies suitable either for utility or non utility applications, including fuel cells and small ( <100 MW) AFBCs in nonutility cogeneration applications, small (< 100 MW) CAES, wind turbines, small ( <50 MW) geothermal plants, batteries, and other solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

A characteristic of the first group of technologies is the likelihood of long preconstruction and construction lead-times—up to 10 years. Although these technologies have the potential for much shorter lead-times---5 to 6 years—problems associated with any new, complex technology may require construction of a number of plants before that potential is met. If the longer lead-times are needed, deployment in the 1990s will be limited because of short time remaining to develop the technologies to a level acceptable to a broad array of utilities.

The technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. For increased contribution in the 1990s, however, most of these technologies will require stepped up development to reduce cost and resolve cost and performance uncertainties that concern utility decision makers and nonutility investors.

It is important to note that this division between these two groups of technologies is not rigid. Some technologies the first group could also benefit from accelerated R&D and some in the sec-

[2]Adapted from D. Spencer, Electric Power Research Institute, ''Remarks on the Importance of a Federal Government Role in Supporting Demonstration Scale Facilities for Fossil and Renewable Energy Technologies,'' testimony presented to the House Committee on Science and Technology, Subcommittee on Energy Development and Applications, June 7, 1984.

ond group could benefit from policies aimed at shortening lead-times. This overlap should be considered in applying policy actions to either group.

Generally, though, the steps necessary to accelerate contribution to electricity supply vary according to the technology. With the first group of technologies, it is necessary, first, to resolve cost and performance uncertainties within the next 5 to 6 years; and second, to take steps to achieve the short lead-time potential for early commercial units. Uncertainties in cost and performance stem largely from the lack of sufficient commercial operating experience to satisfy nonutility investors and utility decision makers. Utility decision makers, in particular, in the wake of their experience with nuclear power, are now particularly wary of new technology, especially large-scale technology, and they impose rigorous performance tests on technology investment alternatives. This conservatism confers added importance to advanced commercial demonstration projects, as mentioned earlier in option Al.

On the other hand, no significant acceleration of existing RD&D schedules for the *basic* designs of the IGCC, large AFBC, and utility-scale geothermal plants is likely to be required for these technologies to be ready for the 1990s. Their transition from demonstration to early commercial units, however, will have to be accelerated if the technologies are to be used in serving demand growth in the 1990s if it occurs. Variations in basic designs or more advanced designs, however, will require additional R&D.

Lead-times being experienced by early commercial projects in both groups of technologies have been longer than anticipated, partially due to the time required for regulatory review. As regulatory agencies become more familiar with the technologies, and their environmental benefits become clearer, the review process should become smoother and more predictable, although this is by no means guaranteed as evidenced by the history of other generating technologies. If there is accelerated demand growth, however, it may be necessary to take those actions to ensure lead-times consistent with those possible for these technologies. Such actions include working closely with regulators, and careful management of construction and early operation. By emphasizing smaller unit size–200 to 300 MW–these actions would be made easier. The success of the Cool Water project shows that such actions are possible and effective.

For the technologies in the second group, where cost and performance are of particular concern, one approach to accelerating development would be to increase or concentrate Federal R&D efforts on those technologies. This could be particularly effective for photovoltaics, solar thermal parabolic dishes, and advanced small geothermal designs.

### Option A3: Increase assistance to vendors marketing developing technologies in foreign countries

The new generating technologies that appear to show the most promise for substantial deployment in the 1990s are those that currently serve or have the opportunity to serve markets other than the domestic utility grid. Such markets are especially important as long as demand growth for new electric generating capacity is low and while cost and performance of these technologies are uncertain in grid-connected applications. For some of these technologies these markets are foreign. Efforts on the part of the U.S. Government to assist in establishing access to markets for new generating technology equipment in foreign countries could be very important to the near-term viability of some of these technologies. Such efforts might include support for formation of renewable export trading companies, loan guarantees, information dissemination, and help with joint venture and licensing applications in foreign countries.

The pressures of competition from foreign vendors, many of which are heawly supported by their governments, as well as the current lack of U.S. demand for some of these new technologies in grid-connected power generation applications raises the concern over the continued commitment of U.S. firms to developing these technologies. This concern is heightened by pending changes in favorable tax treatment for renewable energy sources. For some domestic firms who are working on technologies such as wind, solar thermal electric, and photovoltaics (at least those focusing on concentrator technologies), the survival of some domestic firms may be at stake. They may not be able to or willing to compete in world markets over the next decade. However, they may need those markets until their technologies can compete in the U.S. grid-connected power generation market.

### Option A4: Increase resource assessment efforts for renewable energy resources

In those regions where renewable energy sources show promise for commercial application, a well-defined resource is essential for assessing the economics of proposed wind, geothermal, and solar power generating projects and for CAES projects. For example, there can be a several hundred percent difference in the energy generated by the same wind machines using different distributions of the same annual mean wind speed; an untested site may require up to 3 years of data to confirm the extent and nature of the wind resource at that site.

Reliable resource data lessens the uncertainty in energy production and hence the risk of insufficient project revenues. Some industry observers[3] feel that, at least in the case of wind, "knowledge of the wind resource—its location and intensity—is the cornerstone to the development of wind energy."[4] Lack of a detailed resource base is also an important factor in geothermal development and, to a lesser extent, in solar thermal electric and photovoltaic development.

### Option A5: Improve collection, distribution, and analysis of information

A serious disadvantage facing all the developing technologies is the lack of adequate information on the technologies and their markets among those whose decisions are important to their commercial deployment—investors, regulators, the general public and others.[5]

Non utility market information, in particular, is generally not available because these markets are not yet well developed.[6] The lack of information increases the general level of uncertainty and risk, and favors conventional technologies and markets about which more is known.

Programs designed to deliver accurate and useful information in a timely manner to the relevant individuals and groups would be helpful in accelerating deployment of the technologies. Also, efforts to increase the capability to use the information properly could be effective. Such efforts might include the training of individuals, the development of appropriate analytical methods, and acquainting people with the technology through demonstration projects.[7]

[3] *Final Report of the Wind Energy Task Force*, unpublished report, Oregon Alternate Energy Development Commission, June 1980.

[4] S. Sadler, et al., *Windy Land Owner's Guide* (Salem, OR: Oregon Department of Energy, 1984).

[5] This is a common impediment encountered by developing technologies during the commercial transition. See Arthur D. Little, Inc., *Barriers to Innovation in Industry: Opportunities for Public Policy Changes* (Washington, DC: Arthur D. Little, Inc., 1973).

[6] The inadequacy of information on nonutility markets was pointed out in: "FERC Wants Cogeneration Tally; Results May Question Central Plant Need," *Electric Utility Week*, Mar. 18, 1985, p. 3. The article raises the possibility that the failure to adequately consider non utility power producers may severely distort analyses such as those performed by the Department of Energy. The Energy Information Administration, for example, in its *Annual Energy Outlook-1984*, does not include any nonutility capacity in its calculations of plant construction through the year 1995.

[7] For an informative discussion of the importance to public utility commissions of the collection, distribution, and analysis of information, see: S. Wiel, Commissioner, Public Service Commission of Nevada, Statement before the Subcommittee on Energy Development and Applications, Committee on Science and Technology, House of Representatives, U.S. Congress, Mar. 5, 1985.

# GOAL B: ENCOURAGE NONUTILITY ROLE IN COMMERCIALIZING DEVELOPING TECHNOLOGIES

### Option B1: Continue favorable tax policy

The Renewable Energy Tax Credits (RTCs) have been an important contributor to the Federal policy of supporting the infant renewable energy industry.[8] While the RTCs have been in effect since 1978, they have only been utilized to a significant degree since 1981 for electric power projects and are only applicable to nonutility facilities. For wind projects, in particular, the credits seemed to have spurred development significantly for two reasons:

1. With the tax credits, projects with design specifications using current cost and performance technology present competitive rates of return for prospective investors, particularly in California where State tax credits and high PURPA avoided cost rates are additional incentives. Even if the design specifications for a prospective project are not realized, as has been the case for a large number of first generation wind projects, the tax benefits alone associated with these projects, many of which were initiated to test innovative designs, have been sufficient to attract considerable investment interest. This has been particularly true for investors with income from other investments.

   For example, using OTA's cost and performance estimates (appendix A), the cumulative tax benefits–including accelerated depreciation allowances (ACRS), Investment Tax Credits (ITCs), and RTCs–shows that wind turbines as well as geothermal projects are attractive investment opportunities under all reasonable cost and performance scenarios. PVs become competitive under the "best case" scenario. Some of the details of this analysis are illustrated in figure 10-1.[9]
2. While the first generation wind prolects in California generally did not perform well, they served as the "test bed" for small wind machines (less than 200 kw) that have not been the focus of the Federal R&D program. Indeed, the wind industry is currently moving from these first generation small machines to medium-sized machines (200 to 1,000 kW) as the technology matures.

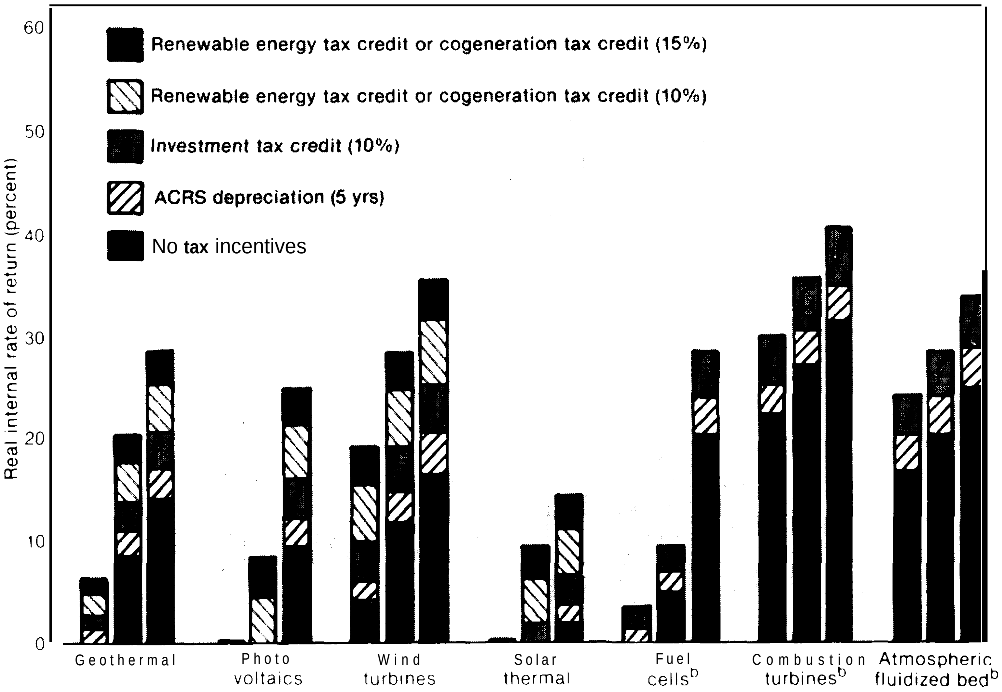
The effect of the RTCs on internal rates of return for solar, geothermal, and wind projects is shown in figure 10-1, including the "worst case, " "most likely, " and "best case" cost and performance scenarios defined in chapter 4 and appendix A. It should be noted that special investment structures such as safe harbor leases or other tax leveraged vehicles can improve the attractiveness of the investment considerably by limiting risk and/or offering substantial tax benefits (as discussed in chapter 8). Such mechanisms have become more the rule than the exception in the industry in the last several years. As renewable technology matures, the quality of investments will improve regardless of the tax implications, if avoided cost rates remain sufficient as shown in the figure. Figure 10-2 shows the breakeven avoided cost (buy-back) rates necessary to yield a 15 percent real internal rate of return.

The role of the RTC in accelerating commercial development seems to have changed from its original design, at least for the technologies considered in this assessment. The original Federal policy was to provide direct research support to develop the technology and the RTC to accelerate commercial deployment, With decreased Federal R&D support, the RTC appears

[8] The Energy Tax Act ot' 1978; the long-term "suppofl of an infant industry" motivation for the renewable energy credit was quite different from the sister tax credit for conservation which was motivated by the short-term objective tor encouraging energy conservation.

[9] Also see P. Blair, testimony presented in hearings held by Subcommittee on Energy and Agricultural Taxation, Committee on Finance, U.S. Senate, June 21, 1985,

**Figure 10-1.—Tax Incentives for New Electric Generating Technologies: Cumulative Effect on Real Internal Rate of Return[a]**




[a]Reported for each technology with "worst case," "most likely," and "best case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8.
[b]In cogeneration applications.

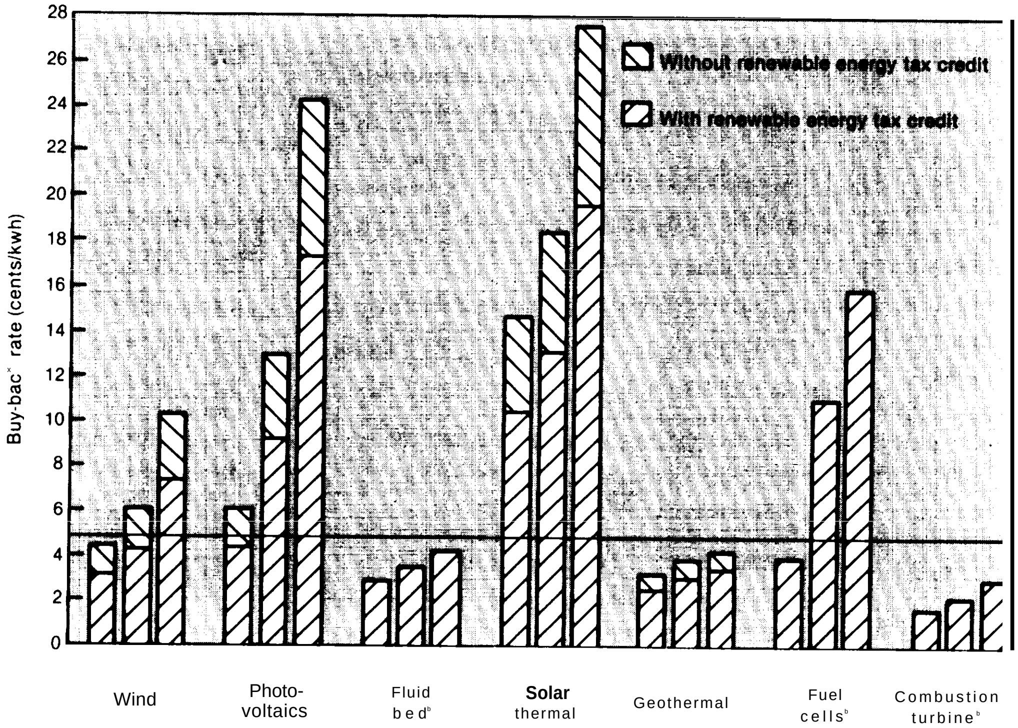
SOURCE: Office of Technology Assessment, U.S. Congress.

to be supporting research and development in the field as well as commercial development. At the same time, there are instances where the RTC has prompted installation of inferior technology that has little possibility of commercial success.

These instances have brought about criticism of the RTCs, particularly for wind, that has resulted in proposals for an alternative PTC that would award the credit based on energy generated rather than the initial investment. These critics have argued that support of innovative designs is not the intent of the credits. Indeed, a PTC would discourage investment primarily oriented toward exploiting tax benefits. Moreover, it would ensure that whatever investments are made would be done so for energy production purposes. A PTC, however, may be difficult to monitor, particularly in non-grid-connected applications. In addition, while PTCs may ensure better performance, it may slow technology development and commercialization since investors would be less likely to test innovative designs. Another implication of the PTC, compared with the RTC, is that it favors technologies in base load cycle applications (with higher capacity factors) such as geothermal and penalizes those in intermediate and peaking applications such as wind or solar. The trade-offs between PTCs and RTCS are illustrated in table 10-2.

The evidence supporting the relative effectiveness of tax incentives for stimulating investment in the electric utility industry itself is not as compelling as the nonutility case. For example, the decrease in the levelized per kilowatt-hour busbar cost for the renewable technologies considered in OTA's assessment, with a 15 percent tax credit over and above the existing tax benefits currently afforded to utilities, is less than 10 percent for all cases. The relative lower effectiveness is mostly explained by utility accounting practices

Figure 10-2.—Breakeven Utility Buy-Back Rates[a]




[a]Reported for each technology with "best case," "most likely," and "worst case" estimates of cost and performance for the reference years defined in ch. 4; basic economics assumptions are given in ch. 8, chart shows buy-back rates necessary to generate a 15% real rate of return on investment.
[b]In cogeneration applications.

which spread the benefits of the tax credit over the life of the facility rather than offering a substantial front-end incentive. For electric utilities, other actions than tax preferences (discussed later) may be more effective in stimulating development of new technology.

Since the early 1970s, the Federal policy for encouraging the development of a renewable energy industry centered on an active R&D program to develop the technology (particularly active during the decade of the 1970s) coupled with the tax credits (since the early 1980s) to spur commercial applications. This analysis shows that with declining direct support from Federal RD&D programs, the pace of renewable technology development would slow considerably without the RTC. Indeed, without the credits, only the most mature renewable technologies at the best resource locations would likely be deployed through the 1990s. Even with the tax credits, the application of the renewable technologies considered here will be highly regionally dependent in the 1990s (see chapter 7). In regions where the wind, solar, and geothermal resources are of high quality, though, the renewable could be important contributors to both new and replacement generating capacity.

Many industry observers argue that a gradual phasing out of the RTC rather than their currently scheduled termination at the end of 1985 would give the renewable power industry a better chance to develop technology to the point where it might compete effectively in the 1990s. in particular, a 3-year phase-out of the credit for wind and geothermal could benefit those technologies considerably and increase deployment in the

## Table 10-2.—Alternative Tax Incentives: Cumulative Effect on Real Internal Rate of Return

| | Real internal rate of return (percent) | | | | | | |
|---|---|---|---|---|---|---|---|
| Tax incentive | Geothermal | Photo-voltaics | Wind turbines | Solar thermal | Fuel cells | Combustion turbine | Atmospheric fluidized-bed |
| ***"Worst case" cost and performance:*** | | | | | | | |
| No tax incentives[a] | 0.1% | 0.0% | 4.1% | 0.0% | 0.0% | 22.3% | 16.9% |
| Current tax incentives[b] | 4.9 | 0.0 | 19.1 | 0.0 | 3.4 | 30.0 | 24.3 |
| Investment Tax Credit (10%)[c] | 2.7 | 0.0 | 9.9 | 0.0 | 3.4 | 30.0 | 24.3 |
| Production Tax Credit:[d] | | | | | | | |
| $0.01/kWh | 6.3 | 0.0 | 14.9 | 0.0 | 7.7 | 39.1 | 29.8 |
| $0.02/kWh | 6.7 | 0.0 | 16.8 | 0.1 | 8.6 | 40.5 | 31.7 |
| $0.03/kWh | 6.8 | 0.0 | 17.9 | 0.1 | 9.1 | 40.5 | 32.6 |
| $0.05/kWh | 7.0 | 0.0 | 19.0 | 0.2 | 9.5 | 40.5 | 33.7 |
| Renewable Tax Credit:[e] | | | | | | | |
| 10% without 5 year ACRS | 2.8 | 0.0 | 11.6 | 0.0 | 3.6 | 32.0 | 24.6 |
| 10% with 5 year ACRS | 4.9 | 0.0 | 15.5 | 0.0 | 6.6 | 36.1 | 29.6 |
| 15% without 5 year ACRS | 3.8 | 0.0 | 14.5 | 0.0 | 5.1 | 35.3 | 27.3 |
| 15% with 5 year ACRS | 6.3 | 0.0 | 19.1 | 0.0 | 8.9 | 39.7 | 32.9 |
| ACRS depreciation:[f] | | | | | | | |
| 5 years | 1.2 | 0.0 | 5.9 | 0.0 | 1.3 | 25.2 | 20.2 |
| 10 years | 1.1 | 0.0 | 5.1 | 0.0 | 1.2 | 23.2 | 18.6 |
| ***"Most likely" cost and performance:*** | | | | | | | |
| No tax incentives[a] | 8.9% | 0.0% | 11.7% | 0.0% | 5.0% | 27.2% | 20.4% |
| Current tax incentives[b] | 17.8 | 8.4 | 28.4 | 9.5 | 9.5 | 35.8 | 28.6 |
| Investment Tax Credit (10%)[c] | 13.9 | 0.0 | 18.9 | 1.8 | 9.5 | 35.8 | 28.6 |
| Production Tax Credit:[d] | | | | | | | |
| $0.01/kWh | 19.2 | 5.2 | 24.6 | 6.1 | 14.1 | 46.2 | 34.9 |
| $0.02/kWh | 20.4 | 6.7 | 26.8 | 7.5 | 15.3 | 47.0 | 37.0 |
| $0.03/kWh | 20.8 | 7.5 | 27.8 | 8.2 | 15.9 | 47.0 | 37.9 |
| $0.05/kWh | 21.2 | 8.4 | 28.8 | 9.1 | 16.3 | 47.0 | 38.8 |
| Renewable Tax Credit:[e] | | | | | | | |
| 10% without 5 year ACRS | 13.9 | 1.5 | 19.7 | 2.1 | 9.5 | 38.1 | 29.1 |
| 10% with 5 year ACRS | 17.8 | 4.3 | 24.7 | 6.2 | 13.3 | 42.3 | 34.4 |
| 15% without 5 year ACRS | 15.8 | 4.3 | 22.7 | 4.0 | 11.3 | 41.7 | 32.2 |
| 15% with 5 year ACRS | 20.4 | 8.4 | 28.4 | 9.5 | 15.8 | 46.2 | 37.9 |
| ACRS depreciation:[f] | | | | | | | |
| 5 years | 11.2 | 0.0 | 14.7 | 0.0 | 7.0 | 30.5 | 24.1 |
| 10 years | 10.3 | 0.0 | 13.2 | 0.0 | 6.4 | 28.2 | 22.3 |
| ***"Best case" cost and performance:*** | | | | | | | |
| No tax incentives[a] | 14.2% | 9.4% | 16.6% | 1.7% | 20.3% | 31.5% | 24.8 |
| Current tax incentives[b] | 25.5 | 24.8 | 35.5 | 14.4 | 28.4 | 40.7 | 33.9 |
| Investment Tax Credit (10%)[c] | 20.7 | 16.0 | 25.2 | 6.6 | 28.4 | 40.7 | 33.9 |
| Production Tax Credit:[d] | | | | | | | |
| $0.01/kWh | 27.0 | 20.6 | 31.9 | 10.2 | 36.4 | 52.5 | 41.0 |
| $0.02/kWh | 28.4 | 22.6 | 34.2 | 11.8 | 38.1 | 52.5 | 43.2 |
| $0.03/kWh | 29.1 | 23.7 | 35.2 | 12.7 | 38.6 | 52.5 | 44.3 |
| $0.05/kWh | 29.4 | 24.7 | 36.4 | 13.8 | 38.6 | 52.5 | 44.7 |
| Renewable Tax Credit:[e] | | | | | | | |
| 10% without 5 year ACRS | 20.8 | 16.0 | 25.6 | 6.7 | 28.9 | 43.3 | 34.7 |
| 10% with 5 year ACRS | 25.5 | 21.3 | 31.6 | 11.2 | 34.2 | 47.6 | 40.2 |
| 15% without 5 year ACRS | 23.3 | 18.7 | 28.9 | 8.7 | 32.0 | 47.1 | 38.1 |
| 15% with 5 year ACRS | 28.6 | 24.8 | 35.5 | 14.4 | 37.7 | 51.6 | 43.9 |
| ACRS depreciation:[f] | | | | | | | |
| 5 years | 17.1 | 12.3 | 20.5 | 3.7 | 24.0 | 35.0 | 28.9 |
| 10 years | 15.8 | 11.1 | 18.6 | 3.3 | 22.1 | 32.4 | 26.7 |

[a]Includes Sum of Years Digits depreciation, no Investment Tax Credit (ITC), and no Renewable Tax Credit (RTC).
[b]Includes 5 year ACRS depreciation, 10% ITC, and RTC where applicable.
[c]Includes 5 year ACRS and 10% ITC.
[d]The Production Tax Credit (PTC) is calculated by applying the cents/kWh credit amount to expected yearly electricity production. The credit is applied annually until the cumulative tax credit equals the 15% RTC. The 10% ITC and the 5 year ACRS schedule are also used in computing the PTC.
[e]Includes 10% ITC.
[f]Does not include 10% ITC.

SOURCE: Office of Technology Assessment.

1990s. For solar thermal and photovoltaics, however, a 5-year or more extension or gradual phase-out would more likely be required.

### Option B2: Improve nonuti[ity access to transmission capacity

Some non utility power producers argue that if proposed nonutility generating projects were included more explicitly in utility resource planning considerations, such projects might be better aligned with proposed transmission expansion and reconfiguration plans. Coordination of nonutility generation with utility-owned generation must be balanced against utility concerns about control of generating sources for dispatching and maintenance of system reliability.

Nonutility generating sources might also be more prevalent if power from projects located in one utility service territory could be sent to another utility service territory where, for example, avoided cost payments were higher. Such "wheeling" of power, however, requires transmission capacity to be committed to the project in the former service territory. At low penetration levels of nonutility generating sources wheeling is not likely to be a serious problem. Some State utility commissions have already made wheeling mandatory. At higher levels of penetration, however, utilities might be forced to reconfigure or upgrade existing transmission capabilities to accommodate wheeling and the question of allocation of costs for upgrades becomes an issue.

If the objective is to increase non utility power projects employing new electric generating technologies, revisions to PURPA to modify the wheeling provisions originally enacted might be an effective way to encourage development of such projects. Such modifications could give these producers access to utility markets beyond the service territory in which the project is sited without negotiating complicated individualized wheeling agreements with the local utility. Such modifications might also extend to obligations on the part of the utility in which a project is sited to negotiate with prospective non utility producers on the issue of transmission access.

Modifications to PURPA to broaden the wheeling provisions, however, would have to be carefully constructed since the implications of such modifications vary greatly from region to region as well as from utility to utility within regions. Utility concerns about efficiency and control over the transmission and distribution system must be carefully addressed in any proposed modifications.

Finally, streamlining of Federal licensing and permitting procedures where such procedures apply to transmission projects—i,e., on Federal lands–could reduce the time it takes for PURPA-qualifying facilities to gain access to transmission capacity.

### Option B3: Develop clearly defined and/or preferential avoided energy cost calculations under PURPA

In chapter 8 the avoided energy (and capacity) cost that utilities pay to non utility producers for generated power was identified as one of the key factors affecting the profitability of nonutility power projects. Investors in nonutility power projects seek secure, long-term energy credit and capacity payment agreements with utilities to ensure a stable revenue stream for the project. In States encouraging non utility projects, e.g., California, standard agreements have evolved that are levelized pricing contracts or fixed price schedules negotiated for the duration of the proposed projects. Such standard contracts have greatly increased nonutility generating activity in these States and could provide a model for other States.

In other States, public utility commissions have mandated minimum avoided cost rates—e. g., New York and Iowa have minimum rate of 6 and 6.5 cents/kWh, respectively, for small power producers which are generally above the prevailing avoided cost of the utilities. Attempts to remove such rates through the courts have to date been unsuccessful, although some appeals are still pending. If the courts interpret the primary purpose of PURPA's avoided cost provisions as encouraging small power production, then adoption of such mandatory rates could serve to accelerate small power production substantially in States where these rates exist. If, on the other hand, the courts rule that implementation of PURPA's avoided cost provisions' must consider immediate rate savings for a utility's customers, the future of such rates is less clear since public utility commissions will be obligated to strike a balance between customer savings and incentives for small power producers. The outcome is of considerable importance to the rate of commercial deployment of new generating technologies. Legislative action to co-opt the courts' decisions in this area could serve to reduce uncertainty, and in the process, accelerate deployment of new generating technologies that would qualify for mandatory rates where they exist.

### Option B4: Standardize interconnection requirements

**As the penetration of nonutility** owned and operated dispersed generating sources (DSGs) increases in U.S. electric power systems, the implications for system operation, performance, and reliability are receiving increased attention by the industry. For the most part, however, the technical aspects of interconnection and integration with the grid are fairly well understood and most utilities feel that the technical problems can be resolved with little difficulty. State-of-the-art power conditioners are expected to alleviate utility concerns about the quality of interconnection subsystems.

Prior to 1983, most interconnection configurations were custom-fitted and no standardized guidelines existed. Since 1983, however, the number of applications from DSGS has increased and, as a result, more utilities are developing such guidelines. These individual utility guidelines vary widely, but a number of national "model" guidelines are being developed by standard-setting committees (discussed in chapter 6), although none has yet released final versions. Indeed, these groups are expected to continue to revise draft standards. Even if a consensus standard does emerge, however, widespread utility endorsement is still uncertain. As a result, DSG customers are likely to face different and sometimes conflicting interconnection equipment standards well into the 1990s. This lack of standardization may hamper both the use of DSGs as well as the manufacture of standardized interconnection equipment. Development of a set of national standards for interconnection that could be flexibly interpreted for individual utility circumstances could accelerate deployment of non utility power projects in many regions.

## GOAL C: ENCOURAGE INCREASED UTILITY INVOLVEMENT IN DEVELOPING TECHNOLOGIES

Electric utilities on average currently spend less than 1 percent of gross revenues on R&D, considerably less than most other capital-intensive industries. Traditionally, the response to this concern is that equipment manufacturers and vendors are carrying the principal burden of R&D for the power industry. But, with the decline in new equipment orders in recent years, manufacturers are less likely to commit R&D to new products for which strong markets are not assured. As a result, if R&D activity in new generating technologies is to continue, at least a portion of the burden may fall on the utilities themselves. With environmental and other pressures on utilities to consider new technologies, how public utility commissions treat cost of RD&D and of early commercial applications is a pivotal issue. The following are alternative strategies aimed at improving this regulatory environment.

### Option CI: Increase utility and public utility commission support of RD&D activities

**increased** RD&D activity in new generating technologies will require utilities and utility commissions to agree on appropriate mechanisms for supporting such activities. Direct support from the rate base for research activities, such as the allowance for contributions to the Electric Power Research Institute while desirable and important,

38-743 0 - 85 - 11

is not now at a level that would cause significant deployment of these technologies by the **1990s. Allowance** of or even encouragement of a higher percentage of annual revenues to support RD&D activities could be an important step in accelerating commercial applications of new technologies.

Even larger RD&D commitments, however, that involve large capital investments for major demonstration facilities may only be justified by a sharing of the risk between ratepayers, stockholders and, if other utilities would benefit substantially, taxpayers. One mechanism for supporting such projects is to finance a portion of proposed project with an equity contribution from the utility and the rest through a "ratepayer loan" granted by the public utility commission. The public utility commission might argue that a candidate demonstration project is too risky for the ratepayer to be subsidizing, particularly if other utilities could benefit substantially from the outcome, but are not contributing to the demonstration, i.e., sharing in the risk. In such cases, there could be a Federal role. For example, the ratepayer contribution to the demonstration could be underwritten by a Federal loan guarantee, thus transferring at least a portion of the investment risk from the ratepayer to the taxpayer.

Finally, since high interest rates and high capital costs have discouraged utilities from making investments in new generating capacity, a wide variety of regulatory changes have been suggested that would make it easier to resume construction programs. These include:

1. rate base treatment of utility assets that take inflation into account—sometimes called "trending" the rate base; l"
2. allowance of some or all construction work in progress (CWIP) to be included in the rate base; and
3. adoption of real rates of return on equity commensurate with the actual investment risk.

[10] Trended rate base proposals are discussed in U.S. Congress, Office of Technology Assessment, *Nuclear Power in an Age of Uncertainty* (Washington, DC: U.S. Government Printing Office, February 1984), OTA-E-216.

These options are all aimed at evening out rate increases (prevention of so called "rate shock") and providing more financial stability for utilities. They would, however, reduce the attractiveness of smaller, modular generating technologies relative to larger units since the options transfer some of the investment risk from the stockholder to the ratepayer. While all capital projects—large or small—wou ld benefit by this risk transfer in terms of lower capital costs, the larger the project the greater the net savings to the utility. Whether this is sufficient to outweigh the benefits of smaller units in a period of uncertain demand growth would depend on the particular utility and its longer term outlook.

### Option C2: Promote involvement of utility subsidiaries **in new technology development**

Some electric utilities are using (and many are considering) the use of regulated or unregulated affiliated interests (corporate subsidiaries or other holding company structures) to initiate new technology projects where they have identified a project as an attractive investment opportunity but riskier than more traditional utility investments, i.e., the utility's allowed rate of return is not commensurate with the project's perceived financial risk. In practice, this usually amounts to a situation where the public utility commission agrees to permit a project to proceed but does not give assurances that the entire final project cost will be permitted to enter the rate base.

Using an unregulated affiliated interest to carry out new technology projects allows utilities to finance such projects with sources from the capital markets since higher rates of return can be offered to attract capital. It is also one example of how utilities are diversifying into other lines of business. As discussed in chapter 3, electric utility diversification activities are already widespread and growing. Most of these activities (74 percent according to a recent Edison Electric institute survey) involve fuel exploration and development, real estate, energy conservation services, fuel transportation, district heating and cogeneration, and appliance sales. A small percentage (6 percent) do, however, involve alternative technology projects. Generally diversification has led to:

1. A higher return for investors, increase in price-earnings ratio and, as a result, an improved standing in the financial community and a lowering in the cost of capital. Diversified utilities have consistently outperformed nondiversified utilities in the stock market.
2. More efficient use of company assets including labor, customer base, computational facilities, and services.
3. Diversification, protection, and stable pricing of fuel supplies through diversification into fuel acquisition activities and alternative technology projects.
4. An ability to take advantage of favorable tax benefits not afforded to-regulated public utilities.

The problems of potential cross-subsidization of unregulated projects from regulated interests has to be monitored closely by public utility commissions as they allow utilities to become involved in diversification activities.

### Option C3: Resolve siting and permitting questions for developing technologies

To date, the rate of deployment of some new generating technologies in both utility and nonutility applications is being lowered because lead-times being experienced by early commercial projects have been longer than anticipated, partially due to the time required for regulatory review. As regulatory agencies become more familiar with the technologies and their environmental impacts become clearer, the time to complete such reviews could decrease, although as noted earlier this is by no means guaranteed. Action to educate regulators and all others who would ultimately be affected by eventual deployment of the technology in the course of demonstrations might reduce the lead-times of early commercial units. For example, close coordination with State and Federal regulatory agencies as well as public utility commissions during demonstration projects should be a major feature of these projects. Finally, as noted for non utility projects discussed earlier, streamlining of Federal licensing and permitting procedures where such procedures apply to transmission projects could reduce lead-times considerably.

### Option C4: Other legislative initiatives: PIFUA, PURPA, and deregulation

In addition to maintaining a continued presence in research, development, and demonstration as well as implementing environmental policy affecting power generation, e.g., administration of the Clean Air Act, several possible Federal policy decisions affecting electric utilities could influence the rate of commercial development of new generating technologies over the next 10 to 15 years. These include removal of the Powerplant and Industrial Fuel Use Act (PIFUA) restrictions on the use of natural gas, extension of complete PURPA Section 210 benefits to electric utilities, and increased steps toward deregulation of power generation and bulk power transfers. All of these actions could increase the rate of deployment of developing generating technologies, but their other effects have to be carefully reviewed before and during implementation.

If increased availability of natural gas should occur, a repeal of PIFUA or, at a minimum, a more liberal policy on granting exemptions in power generation applications could, in addition to providing more short-term fuel flexibility for many utilities, be a step toward accelerated deployment of "clean coal" technologies such as the IGCC since they can use natural gas as an interim fuel. In addition, some technologies such as CAES and some solar thermal electric units use natural gas as a supplementary fuel and may or may not fall within the applicable size limits established by PIFUA automatically exempting such installations from the Act.[11] Where exemptions are required, their acquisition introduces delays or even the possibility that approval might be denied.

Permitting utilities to participate more fully in the PURPA Section 210 benefits of receiving avoided cost in small power production would most likely result in increased deployment of

[11] Changes in PIFUA would also affect non utility producers, as discussed in ch. 9.

small modular power generating technologies, particularly cogeneration.[12] For example, utilities are currently limited to less than sO percent participation in PURPA qualifying cogeneration facilities. In addition, ratepayers would likely see more of the cost savings resuking from cogeneration if utilities were allowed full PURPA benefits. Currently, ratepayers see only the difference, if any, between the avoided cost and the rate negotiated between the cogenerator and the utility. The owner of the qualifying facility retains the rest of the excess over the cost of generating the power. Similar benefits would accrue to the ratepayer by utility participation in PURPA for other types of generating technologies to the extent that costs of power production fall below avoided costs.

In relaxing this limitation, potential problems requiring attention include ensuring that utilities do not show undue preference for utility-initiated projects in such areas as access to transmission or capacity payments. Moreover, project accounting would probably need to be more segregated from utility operations than non-PURPA qualifying projects in order to ensure that cross-subsidization does not occur that would make utility-initiated projects appear more profitable at the expense of the ratepayer. These concerns can be allayed through carefully drafted legislation or regulatiorls, or through careful State review of utility ownership schemes.

It should be noted, though, that granting of full PURPA benefits to utilities would be viewed with disfavor by most nonutility owners. In particular, allowance of such benefits likely would cause avoided costs to be determined by the cogeneration unit or alternative generation technology itself rather than the fuel and/or capital costs of a conventional plant that would be avoided by a utility as is currently the case. Unless prospective nonutility owners could produce power still cheaper than these newly defined avoided costs, they obviously would not enter into any projects. This would clearly reduce the number of cogeneration and alternative technology power projects started by nonutility investors. This drop-off, however, might be more than compensated by expanded utility involvement. It is also possible that potential cogeneration and alternative technology sites may go unfulfilled if utilities were allowed full PURPA benefits, since many of these site owners—industrial firms and large buildi rigs-may not want utility control over facilities on their site. Here, too, careful establishment of regulations or contracts could protect all parties of interest.

Finally, as perhaps a logical next step to PURPA, a number of proposals for deregulation of the electric power business have been proposed in recent years, ranging from deregulation of bulk power transfers among utilities, to deregulation of generation, to complete deregulation of the industry. While OTA has not examined the implications of alternative deregulation proposals on the rate of commercial development of new generating technologies, such proposals would almost certainly have an impact. The experiences of PURPA and the FERC Bulk Power Market Experiments will be important barometers for assessing the future prospects and desirability of deregulating U.S. electric power generation. It is important to note that allowance of full PURPA benefits for utilities would be a significant step toward deregulation of electric power generation, at least for smaller generation units.

[12] For a more complete discussion, see U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration* (Washington, DC: U.S. Government Printing Office, February 1983), OTA-E-1 92, pp. 20ff.

[13] This experiment deregulates wholesale bulk power transactions among four utilities in the Southwest; see "Opinion and Order Finding Experimental Rate To Be Just and Reasonable and Accepting Rate for Filing, " Federal Energy Regulatory Commission, Opinion No. 203, December 1983.

# GOAL D: RESOLVE CONCERNS REGARDING IMPACT OF DECENTRALIZED GENERATING SOURCES ON POWER SYSTEM OPERATION

In recent years, utilities that interconnect with non utility power producers operating DSGs are concerned about the potential impact of increased penetration of DSGs on overall power quality available in the utility grid as well as proper metering, effect on system dispatching and control, short-term transmission and distribution operations, and long-term capacity planning.

As utilities gain experience with DSGs on their own systems, these concerns are being resolved. However, many utilities are only beginning to gain this experience; the following options are aimed at addressing such concerns.

### Option Dl: Increase research on impacts at varying levels of penetration

While most of the problems associated with incorporating DSGs into the utility grid appear to have technical solutions, the cost and complexity of these solutions may vary considerably across utility systems. In particular, one concern is the potential impact on power quality of high levels of penetration of DSGs on individual distribution feeders. Other issues include protective equipment performance, appropriate safety procedures, system control at the distribution level, and impact on system generation dispatching procedures. Most research to date indicates that at low levels of DSG penetration–up to 5 percent of total installed capacity—there are no ill effects on system operations as measured by indicators such as the area control error (see chapter 6). Beyond a 5 percent penetration, however, there is less agreement among researchers. Research on the conditions under which DSGs would significantly affect system operation over a wide range of utility circumstances would improve utility engineers' ability to assemble appropriate and cost-effective interconnection configurations and control procedures for mitigating potential impacts. Such research could help resolve concerns and serve as a basis for implementing appropriate technology and procedures to accommodate increased penetration of DSGs.

### Option D2: Improve procedures for incorporating nonutility generation and load management in economic dispatch strategies and system planning

**Many** of the problems associated with incorporating DSGs into the utility grid stem from modifications to the grid necessary to accommodate electric generation at the distribution level. Management of "two-way" power flows at the distribution level has added a new level of complexity. Some utilities have developed strategies for incorporating DSGs into economic dispatch strategies but control mechanisms for coordinating a large number of DSGs are generally not available. As the number of DSGs on a utility system increases, the complexity of this coordination becomes more difficult and the need to automate such procedures becomes more important.

Similarly, some recent research sponsored by the Electric Power Research Institute[14] indicates that conventional utility planning models may overstate the reliability benefits of load control. Developing load management systems.[15] attempt to better integrate load management into hourly scheduling of resources in energy control centers. As a result, these new systems also provide better control over load management resources and, hence, more reliability benefits.

[14] Electric Power Research Institute (EPRI), *Effect of Load Management on Reliability* (Palo Alto, CA: EPRI, July 1984), EPRI EA-3575.

[15] Such as B. F. Hastings, "The Detroit Edison Second Generation Load Management System," *Proceedings of the Institute of Electrical and Electronics Engineers (IEEE) Summer Power Meeting,* Paper No. 84-SM-559-1, July 15-20, 1984.

38-743 O - 85 - 12