Chapter 2

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INTRODUCTION

As utilities face the 1990s, the experiences of the 1970s have made them much more wary of the financial risk of guessing wrong and over-committing to large central station coal and nuclear plants. At the same time, there is growing concern by utilities about the possibility of being unable to meet demand, particularly in view of increased uncertainty about future demand growth. In addition, the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), have made the role of non utility power producers increasingly important to the future of U.S. electricity supply. As discussed in chapter 1, one of the strategies being pursued by utilities to operate in this new environment is through increased utilization of smaller scale power production by a variety of both conventional and nontraditional energy conversion technologies.

if electricity demand grows at an average annual rate below 2.5 percent through the 1990s (current estimates range from 1 to 5 percent), the need for new generating capacity is likely to be relatively modest. Responses that include life extension and rehabilitation, increased power purchases, and construction of realizable amounts of conventional generation are likely to suffice. But if demand growth should accelerate, these options may not be enough, and the availability of an array of generating technologies that provide a utility with greater flexibility for meeting load requirements may be desirable.

NEW GENERATING TECHNOLOGIES FOR THE 1990s

A number of developing technologies for electric power generation are beginning to show considerable promise as future electricity supply options. Some of these technologies, such as atmospheric fluidized-bed combustion (AFBC) and integrated coal gasificatiordcombined-cycle (IGCQ conversion, and fuel cells, could pave the way for clean and more efficient power generation using domestic coal resources.

In box 2A, the renewable and nonrenewable technologies considered in this assessment are listed and briefly discussed. Table 2-1 shows those technologies grouped according to the sizes and applications in which they would most likely appear if deployed during the 1990s. Also shown in the table are the principal conventional alternatives against which these technologies are most likely to compete. Applications are divided between those in which electrical power output is controlled by the utility (dispatchable) and those where it is not (nondispatchable). Dispatchable applications are further broken down into base, intermediate, and peaking duty cycles. Nondispatchable applications are divided between those with and without storage capabilities.

Many of these technologies **offer modular design features that eventually could allow utilities to add generating capability in small increments with short lead-times and less concentration of financial capital. Other attractive features common to some but not all of these technologies include fewer siting and regulatory barriers, reduced environmental impact, and increased fuel flexibility and diversity.** 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, most developing technologies will not be in a position to contribute more**

[1]For purposes of this report we define renewable technologies as those that do not use conventional fossil and nuclear fuels, i.e., solar thermal-electric, photovoltaics, wind turbines, and geothermal. All others we refer to as nonrenewable technologies.

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Table 2-1 .—Selected Alternative Generating and Storage Technologies: Typical Sizes and Applications in the 1990s

Typical configurations in the 1990s

Installation size (MW)	Dispatchable applications: Base load (60-700/0 CF)	Dispatchable applications: Intermediate load (30-400/0 CF)	Dispatchable applications: Peaking load (&150/o)	Nondispatchable applications[b]: Intermittent (w/o storage)	Nondispatchable applications[b]: Others (not utility controlled)
Greater than 250 MWe	Coal gasification/ combined-cycle	Coal gasification/ combined-cycle	n.a.		
	.... Conventional coal				
51-250 MWe	Geothermal Atmospheric fiuidized-bed combustor	Atmosphere fluidized-bed combustor Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (maxi CAES) Solar thermal (w/storage)	Solar thermal Wind	Atmospheric fluidized-bed combustor Solar thermal (w/storage)
	.... Combined-cycle plants	.... Combined-cycle plants	.... Combustion turbine	....	....
1-50 MWE	Geothermal Atmospheric fluidized-bed combustor Fuel ceils	Fuel cells Compressed air storage (maxi CAES) Solar thermal (w/storage)	Compressed air storage (mini CAES) Battery storage Fuel cells Solar thermal (w/storage)	Solar thermal Wind Photovoltaics	Atmospheric fluidized-bed combustor Geothermal Fuel cells Solar thermal (w/storage) Battery storage Compressed air storage (mini CAES) Geothermal
	....	....	.... Combustion turbine	....	.... Combustion turbine
Less than 1 MWe				Solar thermal Wind Photovoltaics	Fuel cells Battery storage

NOTES: For each unit size and application, new technologies are shown above the dotted line and conventional technologies are shown below the dotted line
CF = capacity factor and n.a. = not applicable.
[a]Dispatchable technologies may not be utility-owned.
[b]Note that nondispatchable technologies may serve base, intermediate, or peaking loads

SOURCE. Office of Technology Assessment

than a few percent of total U.S. electric generating capacity in the 1990s, and therefore, will not be of much help in meeting accelerated demand, should it occur.[2]

Cost and Performance

The current cost and performance characteristics (including the uncertainty in both cost and performance) of most new technologies are not generally competitive with conventional alternatives. s Cost reductions, performance improvements, and resolution of uncertainties will all occur as these technologies mature. The rate at which this maturity occurs depends on: 1) sustained progress in research, development, and demonstration to reduce cost, improve performance, and reduce uncertainty in both cost and performance; and 2) continued active demonstration of the technologies, particularly in utility applications to develop the commercial operating experience necessary before utility decision-makers will consider a new technology seriously. Utility and nonutility interest in these technologies is also affected by a wide range of other factors relating to environmental benefits, siting requirements, and public acceptance.

Lead-Times

Common to the deployment of all electric generating technologies is the need for planning, design, licensing, permitting, other preconstruction activities, and finally construction itself. These steps with some technologies, for early units at

‘Here and elsewhere in this report, a contribution to U.S. electricity supply is considered “significant” when it amounts to more than 5 to 10 percent of total generating capacity, or the equivalent in terms of electricity storage or reduced demand.

[3]In particular, with conventional generating capacity in smaller unit sizes such as conventional combustion turbines, advanced combined cycle plants, slow-speed diesels, and participation in conventional cogeneration projects.

a minimum, may take long periods of time—up to 10 years or more. This means that if those technologies still undergoing development are to be commercially deployed in the 1990s, there may be as little as 5 or 6 years in which to complete development and establish in the minds of investors that their costs, performance, and other attributes fall within acceptable ranges.

Specific Generating Technologies

The relative importance of efforts to improve cost and performance versus the need to shorten lead-times in order to attain commercial status varies by technology. This distinction, i n particular, makes it convenient to divide the technologies considered here into two basic groups:

1. The first consists of technologies envisioned primarily for direct electric utility applications, and includes IGCC plants; large (> 100 MW) AFBC; large (>100 MW) compressed air energy storage (CAES) facilities; large (>50 MW) geothermal plants; utility-owned fuel cell powerplants; and solar thermal central receivers.
2. The second group consists of technologies that are characterized as suitable either for utility or nonutility applications, and includes small (<100 MW) AFBCs in nonutility cogeneration applications; fuel cells small (< 100 MW) CAES; small (<50 MW) geothermal plants; batteries; wind; and direct solar power generating technologies such as photovoltaics and parabolic dish solar thermal.

In both groups, the goal of research, development, and demonstration is to improve cost and performance characteristics to a point where the technologies are commercially competitive. For the first group of technologies, however, the likelihood of long lead-times for early commercial units is the primary constraint to extensive use in the 1990s. Technologies in the second group are likely to have shorter lead-times and are often smaller in generating capacity. For most of them to make a significant contribution in the 199os, however, their research, development, and demonstration will have to be stepped-up in order to reduce cost to levels acceptable to utility decision makers and nonutility investors, and resolve cost and performance uncertainties.

It is important to note that the distinction between these two groups of technologies is not rigid. Technologies in the first group also could benefit from accelerated research and development while those in the second group could be held back by long lead-times.

In addition, many of the technologies in the second group are small enough to qualify as small power producers employed in nonutility power generating projects operating under the provisions of PURPA. **The existence of a wide variety of markets and interested investors outside the electric utilities increases the likelihood that at least some of these technologies will be deployed.**

Because of its modular nature and positive environmental features, the IGCC has the potential for deployment lead-times of no more than 5 to 6 years. Early commercial units, however, may require longer times—up to 10 years—because of regulatory delays, construction problems, and operational difficulties associated with any new, complex technology; and it may take a number of commercial plants before the short lead-time potential of the IGCC is realized. In addition, despite the success of the Cool Water demonstration project, a 100 MWe IGCC plant that has increased electric utility confidence in the technology, more operating experience is likely to be required before there will be major commitment to the IGCC by a cautious electric utility industry. Therefore, **unless strong steps are taken to work closely with regulators and to assure quality construction for these initial plants, there may be insufficient time remaining after utilities finally make a large commitment to the** IGCC **for the technology to make a significant contribution before** 2000. As has been shown in the Cool Water project, though, such steps are possible, and they may be facilitated if initial commercial units are in the 200 to 300 MWe range rather than the current design target of 500 MWe.

The first large (about 150 MW), "grass-roots" (i.e., not retrofits of existing facilities) AFBC installations for generating electricity also may be subject to long lead-times. Moreover, a large AFBC demonstration unit probably will not even be operating until 1989. It now appears unlikely that the operation of that unit will be sufficient to justify large numbers of orders within the first few years of the 1990s. The AFBC, however, also has the potential for needing lead-times on the order of only 5 years. Further, favorable experience with smaller AFBC cogeneration units and AFBC retrofit units which will be in service by 1990 may provide the commercial experience needed to accelerate deployment of the larger units.

Foremost among new technologies offering the potential of significant deployment in the 1990s are small (below 100 MWe) AFBC plants in cogeneration applications and larger (100 to 200 MWe) AFBC **retrofits to existing coal-fired powerplants.** By 1990, plants of both types will be operating. Over a dozen commercial cogeneration plants using AFBC have been started by non utilities, and two large utility retrofit projects are underway. These first plants appear capable of producing electricity at lower costs than their solid-fuel burning competitors (including the IGCC and large, electric-only, grass-roots AFBCs) in the 1990s. The prospects are good that additional orders—perhaps mostly from nonutilities—will be forthcoming and that large numbers of these AFBC units could be operating by the end of the century.

While the prospects for wind turbines are clouded by the anticipated termination of the Renewable Energy Tax Credits (RTC) and other potential tax changes, the outlook nevertheless appears promising. By the end of 1984, an estimated 650 MWe were in place in wind farms in the United States, mostly in California (550 MWe). Over the early 1980s, capital costs have dropped rapidly and performance improved swiftly, **Improvements are expected to continue, and the cost of electric power from wind turbines, even unsubsidized ones, in high-wind parts of the country may soon be considerably lower than power from many of their competitors.** The rate of improvement will be heavily influenced by future trends in the avoided costs or "buy-back rates" offered by utilities to nonutility electricity producers. Should these costs be low or uncertain, technological development and application will be slowed. Conversely, high avoided costs, stimulated perhaps by rising oil and gas prices or shrinking reserve margins of generating capacity, might considerably accelerate their contribution.

Although geothermal development has been substantial compared to other technologies, most of this development has occurred at The Geysers in California, an unusual high-quality dry steam resource (one of only seven known in the world) that can be tapped with mature technology. All other geothermal resources in the United States require less developed technology to generate power. Two developing geothermal technologies, though, are currently being demonstrated on a small scale and show promise for commercial applications in the West. Current evidence indicates that these technologies—dual flash and binary systems—are very close to being commercial, and that cost and performance will be competitive. Small binary units (about 10 MWe) are already being deployed commercially. These developments, coupled with the fact that the technologies can be put in place with lead-times of 5 years or less, suggest that they could produce considerable electric power in the West by the end of the century. As is the case with wind power, **the growth rate of geothermal power will be sensitive to Federal and Mate tax policy.**

Initial commercial application of fuel cells should appear in the early 1990s, primarily fired with natural gas. The large and potentially varied market (it includes both gas and electric utilities as well as cogenerators), the very short lead-times, factory fabrication of components, and a variety of operational and environmental benefits all suggest that when cost and performance of fuel cell powerplants become acceptable, deployment could proceed rapidly. **The principal obstacle to fuel cells making a significant contribution seems to be insufficient initial demand to justify their mass production.** For such demand to appear in the 1990s, extensive commercial demonstration in the late 1980s will probably be necessary,

The development rate of photovoltaics (PV) has been considerable in recent years, but the technical challenge of developing a PV module

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that is efficient, long-lasting, and inexpensive remains. While technical progress and deployment of photovoltaics in the United States are likely to be slowed by termination of the RTC or by other changes in Federal or State tax law, or by declining avoided costs, industry activity is likely to remain intense. Aided by interim markets of specialized applications and consumer electronics, PVS could develop to the point where competitive grid-connected applications at least begin to appear in the 1990s. In the 1990s, overseas markets may dominate the industry's attention, stimulating and supporting improvements in cost and performance, and encouraging mass production to further reduce costs. However, European and Japanese vendors, assisted by their respective governments, have been more successful than U.S. vendors in developing these markets, Foreign competition is likely to be a major concern for U.S. vendors over the next decade.

Of the solar thermal technologies, solar parabolic dish technologies offer the most promise over the next 10 to 15 years; although with current uncertainty in cost and performance, solar troughs may be competitive as well. Characteristics of some solar dish and trough designs indicate that they could be rapidly put in place in areas such as the Southwest. The cost of power generation using these designs in such regions could be very close to those of conventional alternatives. Some demonstration and subsidized commercial units already are operating. **Full commercial application, however, will require further demonstrations of the technologies over extended periods of time; such demonstrations must be started no later than 1990 if the technologies are to be considered seriously by investors in the 1990s.** The likelihood of such demonstrations appears now to depend on the availability of some kind of subsidy. In particular, **development of the technology to date has depended heavily on the RTC.**

Other solar thermal technologies, including central receivers and solar ponds, while showing long-term promise, are unlikely to be competitive with other electric generating alternatives or have sufficient commercial demonstration experience to yield any significant contribution through the 1990s. The central receiver, however, is of continuing interest to a some Southwestern utilities in the long term because it offers a favorable combination of advantages including the potential for repowering applications, high efficiency, and storage capabilities.

Along with new generating technologies, this assessment examined two electric energy storage technologies—compressed air energy storage (CAES) and batteries–that show long-term promise in electric utility applications.

Because of potentially long lead-times, CAES appears to have only limited prospects in the 1990s. The large-scale (>100 MW) version of this technology (called maxi-CAES) currently has an estimated lead-time of 5 to 8 years; of this, licensing and permitting and other preconstruction activities is expected to take 2 to *4* years. Moreover, while commercial installations are operating in Europe, no plant yet exists in the United States. Despite strong evidence that this technology offers an economic storage option, CAES is unlikely to be the target of much investment until a demonstration plant is built. No plans for a demonstration plant currently exist. Further, while a demonstration project should prove the technology, the peculiar underground siting problems and unfamiliarity with the CAES concept may still limit early application.

A smaller alternative–mini-CAES (<100 MW) –promises to have a much shorter lead-time due to modularity of the above-ground facilities and short (30-month) construction lead-times. Here too, however, unless a demonstration plant is started in the next few years, extensive deployment before the end of the century is improbable.

Resolution of a variety of cost and performance uncertainties remains before extensive use of advanced battery storage systems can be anticipated. If the technical problems can be resolved in a timely fashion and demonstration programs are successful, however, rapid deployment in electric utility applications could occur, due to the short lead-times and cost reductions associated with mass production. Of the candidates, lead-acid and zinc-halogen batteries appear to show the most promise.

Table 2-2 summarizes the most promising areas of research and development identified by OTA for the technologies analyzed in this assessment. Atention to these research and development opportunities could accelerate commercial their development through the 1990s. Table 2-3 summarizes the major electric power generating projects utilizing these technologies installed or under construction as of May 1985.

CONVENTIONAL ALTERNATIVES IN THE 1990s

The contribution of developing technologies over the next *two* decades depends in part on the relative cost and performance of conventional generating options as well as a variety of options for extending the lives or otherwise improving the performance of existing generating facilities.

New Capacity

To the extent that new generating capacity is needed at all over the next two decades, conventional pulverized coal plants, combustion turbines, and advanced combined-cycle plants will continue to be the principal benchmark against which utilities and others will compare developing generating technologies. Utilities are very interested, however, in smaller unit sizes of even these technologies. Also, if nuclear power is to become a realizable choice again for utilities, it is likely to involve smaller, standardized units.

If hydroelectric opportunities are available, they are likely to be exploited in both run-of-river and pumped storage applications; few new hydroelectric opportunities, though, are likely through the 1990s. Similarly, refuse steam plants, biomass technologies (e. g., wood waste-fired power generation), slow-speed diesels, and vapor-dominated geothermal plants all use mature technologies so that where opportunities exist, they are likely to be chosen over newer technologies.

In addition, enhancements to conventional plants such as limestone injection in coal boilers, coal-water fuel mixtures, and others will all be reviewed carefully along with new generating technologies as utilities plan for new capacity. The availability of such enhancements could significantly affect the relative attractiveness of new technologies in the 1990s.

Plant Betterment

By 1995, the U.S. fossil steam capacity will have aged to the point where over a quarter of the coal and nearly half of the oil and gas steam units nationwide will be over 30 **years old.** In the past, the benefits of new technology *often* outweighed the benefits of extending the useful lives of existing generating facilities, rehabilitating such facilities to improve performance or upgrade capacity, or even repowering such plants with alternative fuels. Ail of these so-called plant betterment options are receiving renewed interest by utilities because plants "reaching their 30th birthday" over the next decade have attractive unit sizes (100 MW or larger) and performance (heat rates close to 10,000 Btu/kWh). For that reason, **rehabilitating or simply extending the lives of such units, frequently at much lower anticipated capital costs than that of new capacity, are often very attractive options for many utilities.** Prospects are particularly bright if units are located at sites close to load centers and the rehabilitation does not trigger application of New Source Performance Standards, i.e., more stringent air pollution controls.

In many instances, plant betterment can also improve efficiency up to 5 to 10 percent and/or upgrade capacity. Additional benefits from such projects include possible improvements in fuel flexibility or reduced emissions of existing generating units at modest cost relative to that of new capacity. Finally, an initial market for some new technologies such as the AFBC are in repowering applications, e.g., where an existing pulverized coal plant is retrofitted with an AFBC boiler.

Load Management

Load management refers to manipulation of customer demand by economic and/or techni-

Table 2-2.—Areas of Principal Research Opportunities: Developing Technolgies for the 1990s

Wind:
1. Development of aerodynamic prediction codes
2. Development of structural dynamic codes
3. Fatigue research
4. Wind-farm wake effects
5. Development of acoustic prediction codes

Solar thermal electric:

General:
1. Low cost, reliable tracking hardware

Solar ponds:
1. Physics and chemistry
2. Design and performance analysis
3. Construction techniques
4. Operation and maintenance

Central receivers:
1. Physics and chemistry
2. Development and long-term testing of cheap and durable scaled-up molten-salt subsystems (including receiver, pumps, valves, and pipes)

Parabolic dishes:
1. Durable engines
2. Cheap, high-quality, durable reflective materials (polymers)
3. Long-life Stirling and Brayton heat engines

Parabolic troughs:
1. Inexpensive, long-lived, high-temperature thermal-storage media
2. Cheap, leak-resistant, well-insulated receiver-tubes
3. Cheap, high-quality, durable reflective materials (polymers)

Photovo/talcs:
1. Highly efficient, long-lived, mass-produced cells; especially those suitable for use with concentrators
2. Cheap semiconductor-grade silicon
3. Cheap, durable, and reliable modules and module subcomponents (especially the optics and cell mounts for concentrator modules)
4. Reliable, inexpensive and durable “balance of systems, ” especially tracking systems and power conditioners

Fluidlzed-bed combustors:

Circulating-bed AFBCS:
1. Cheap, durable, and reliable equipment for separating solids from gas streat
2. Erosion- and corrosion-resistant materials and designs

Bubbling-bed AFBCs:
1. Adequate sulfur capture by limestone sorbent
2. Effective fuel-feed systems
3. Erosion- and corrosion-resistant materiais and designs

Integrated gasificatlon/combined.cycie:
1. Cheap, durable, reliable, and efficient combustion turbines and combined-cycle systems
2. Erosion- and corrosion-resistant materials
3. Gasifiers capable of effectively converting a variety of fuels
4. Design-specific research requirements:
   a. Moving-bed gasifiers: full utilization of fines and hydrocarbon liquids
   b. Fluidized-bed gasifiers: full carbon conversion
   c. Entrained flow gasifiers: raw gas cooling without excessive corrosion or ash entrainment

Energy storage:

Batteries:
1. Cheap, highly active, and long-lived (especially corrosion-resistant) catalysts
2. Corrosion-resistant structural materials
3. Low-cost and long-lasting electrolytes

Compressed-air energy storage:
1. Corrosion-resistant equipment (especially turbine blades and underground equipment)
2. Durable, reliable, and inexpensive recuperator (recuperator discharges heat from combustion turbine gases to incoming compressed air)
3. Lower cost of existing underground storage sites
4. Improved recovery of compression heat
5. Geologic response to air cycling in reservoir

Load management technologies:

Meters:
1. Mass-produced, inexpensive, durable, reliable solid-state devices capable of operating in adverse environments
2. Meter capable of sustaining operation during power outages

Communications systems:
1. Inexpensive, reliable, and durable residential receivers or transponders

Logic systems:
1. Development of appropriate software

Fuel cells:
1. Lower cost and more efficient catalysts
2. Less corrosive and temperature-sensitive structural materials
3. Higher power densities via:
   a. Improved coolig systems
   b. Improved oxygen flows
   c. Improved cell geometry
4. More stable electrolytes
5. Longer stack life

Geothermal:
1. Inexpensive, durable, and reliable down-hole pumps
2. Detailed resource assessment
3. Inexpensive, durable, and reliable well casing materials

Dual flash:
1. Cheap, durable, and reliable equipment for removing noncondensable gases and/or entrained solids from brines
2. Reliable operation in highly saline environments

Binary:
1. Inexpensive, durable working fluids
2. Equipment durability and reliability in highly saline environments

SOURCE: Office of Technology Assessment.

Table 2-3.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985

Technology	Capacity	Location	Primary sources of funds	Status
Wind turbines[a]	550+ MWe (gross)[b]	California wind farms	Nonutility	Installed
	100+ MWe (gross)[c]	U.S. wind farms outside of California	Nonutility	Installed
	? MWe[d]	All US. wind farms	Nonutility	Under construction (1986)
Solar thermal electric:				
Central receiver	10 MWe (net)[e]	Daggett, CA	Utility, nonutility, and Government	Installed
	0.75 MWe	Albuquerque, NM	Utility, nonutility, and Government	Installed
Parabolic trough	14 MWe (net)	Daggett, CA	Nonutility	Installed
	30 MWe (net)	Daggett, CA	Nonutility	Under construction (1986)
Parabolic dish	0.025 MWe (net)[f]	Palm Springs, CA	Government	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Installed
	2 × 0.025 MWe (net)[f]	Various locations	Nonutility	Under construction
	3.6 MWe	Warner Springs, CA	Nonutility	Installed
Solar pond	None			
Photovoltaics:				
Flat plate	1 MWe (de, gross)	Sacramento	Utility and Government	Installed
	1 MWe (de, gross)	Sacramento, CA	Utility and Government	Under construction (1985)
	1 MWe (de, gross)	Hesperia, CA	Nonutility	Installed
	6.5 MWe (de, gross)	Carrisa Plains, CA	Nonutility	Installed
	0.75 MWe (de, gross)	Carrisa Plains, CA	Nonutility	Under construction
Concentrator	4.5 MWe (de, gross)	Borrego Springs, CA	Nonutility	Installed
	1,5 MWe (de, gross)	Davis, CA	Nonutility	Installed
	3.5 MWe (de, gross)	Barstow, CA	Nonutility	Installed
Geothermal:				
Dual flash	10 MWe	Brawley, CA	Utility/nonutility	fnstalled
	10 MWe	Salton Sea, CA	Utility/nonutility	Installed
	47 MWe (net)	Heber, CA	Nonutility	Under construction (1985)
	32 MWe (net)	Salton Sea, CA	Nonutility	Under construction (1985)
Binary:				
Small	2 x 3.5 MWe	Mammoth, CA	Nonutility	Installed
	3 x 0.3 MWe	Hammersly Canyon, OR	Nonutility	Installed
	3 x 0.4 MWe	Hammersly Canyon, OR	Nonutility	Installed[h]
	10 MWe	East Mesa, CA	Nonutility	Installed
	1 x 0.75 MWe (gross)	Wabuska, NV	Nonutility	Installed
	3 x 0.35 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	3 x 0.45 MWe (gross)	Lakeview, OR	Nonutility	Installed[h]
	4 x 1.25 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
	3 x 0.85 MWe (gross)	Sulfurville, UT	Nonutility	Under construction (1985)[i]
Large	45 MWe (net)	Heber, CA	Utility, nonutility, and Government	Installed
Fuel cells:				
Large	None			
Small[j]	38 x 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Installed
Small[j]	5 x 0.04 MWe (net)	Various locations	Utility, nonutility, and Government	Under construction
Fluidized.bed combustors:				
Large grass roots	160 MWe	Paducah, KY	Utility[k] and Government	Under construction (1989)
Large retrofit	100 MWe	Nucla, CO	Utility[k]	Under construction (1987)
	125 MWe	Burnsville, MN	Utility[k]	Under construction (1986)
	125 MWe	Brookesville, FL	Nonutility	Under construction (1986)
Small cogeneration	30 MWe	Colton, CA	Nonutility	Under construction (1985)
	25 MWe	Fort Wayne, IN	Nonutility	Under construction (1986)
	15 MWe	lone, CA	Nonutility	Under construction (1987)
	67 MWe	Chester, PA	Nonutility	Under construction (1986)

[a] Includes small- and medium-sized wind turbines.
[b] Approximately 550 MWe were operating i, California at the end of 1984. It is not known how much additional capacity was installed by May 1985.
[c] Approximately 100 MWe were operating outside of California at the end of 1984. It is not known how much additional Capacity had been installed outside California by May 1985.
[d] It is not known how much capacity was under construction on May 1, 1985,
[e] This facility, the Solar One Pilot plant, is not a commercial-scale plant and differs in other important ways from the type of system which might be deployed commercially in the 1990s.
[f] This installation consists of only one electricity producing module; a commercial installation probably would consist of hundreds Of modules
[g] Only 10 percent of the modules were operating at the time because of problems with the power conversion systems,
[h] Installed but not operating, pending contractual negotiations with utilities.
[i] The equipment modules have been delivered to the site; site preparation, however, has nOt started.
[j] These units are not commercial-sc~e units,
[k] Including the Electric Power Research Institute.

Table 2.3.—Developing Technologies: Major Electric Plants Installed or Under Construction by May 1, 1985—Continued

Technology	Capacity	Location	Primary sources of funds	Status
	90 MWe[l]	Decatur, IL	Nonutility	Under construction (1986)
	50 MWe[m]	Cedar Rapids, IA	Nonutility	Under construction (1987)
	3.5 MWe	Pekin, IL	Nonutility and Government	Installed
	28 MWe	Pontiac, MI	Nonutility	Under construction (1986)
	2.8 MWe	Washington, DC	Nonutility and Government	Installed
	24 MWe	Enfield, ME	Nonutility	Under construction (1986)
	20 MWe	Chinese Station, CA	Nonutility	Under construction (1986)
IGCC[n]	100 MWe	Daggett, CA	Utility, nonutility, and Government	Installed
Batteries:				
Lead acid[o]	0.5 MWe	Newark, NJ	Utility and Government	Installed
Zinc chloride	None[p]			
CAES:				
Mini	None			
Maxi	None			

[l]This is the total capacity which may be generated from the four AFBC boilers which will be installed.
[m]This is the total capacity which may be generated from the two AFBC boilers which will be installed.
[n]While this installation, the Cool Water unit, uses commercial-scale components, the installation itself is not a commercial-scale installation.
[o]While this installation at the Battery Energy Storage Test Facility uses a commercial-scale battery module, the installation itself is not a commercial-scale installation
[p]A 0.5-MWe zinc chloride commercial-scale battery module was, however, operating at the Battery Energy Storage Test facility until early 1985.

SOURCE' Office of Technology Assessment

cal means. It is done for the mutual benefit of both utility and customer, usually as a means to provide maximum productivity of the utility's generation and distribution capacity. While load management is not a permanent substitute for new capacity, it can enable a given capacity to satisfy a greater customer base, and operate at maximum efficiency. It is now employed by some utilities and being seriously considered by many others to improve their load factor—the ratio of average to peak load. Since base load generating equipment is generally more thermally efficient than peak load equipment, one of the principal goals of load management is to encourage a shift of demand to off-peak periods. The other is to defer the need for costly new generating capacity by inhibiting demand during peak periods. This assessment focuses on technology-based direct load control technologies employing advanced meters and utility-owned or controlled load control systems. A potentially important feature of load management is that it can help reduce future demand growth uncertainty if the saturation and use of load management devices can be more accurately predicted. If such predictions are not possible, however, then increased load management may actually increase demand uncertainty.

Based on the results of current load management programs and ongoing experiments, load management technologies are expected to be able to be deployed at costs below those associated with many conventional generating alternatives. In many instances, however, these costs cannot be reached without substantial utility demand to encourage manufacturers to realize volume production economies.

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. Commitments to initiate load management systems will also depend on the nature of a utility's demand patterns and capacity mix, the attitudes of utility decision makers, and on public utility commission actions. The degree of public utility commission support, in particular, is likely to be very important over the next decade.

IMPACT OF DISPERSED GENERATING TECHNOLOGIES ON SYSTEM OPERATION

As the participation in U.S. electric power systems of non utility owned and operated dispersed generating sources (DSGs) increases, 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. A number of nontechnical problems remain, though, which could inhibit the growth of DSGs.

Nonutility Interconnection Standards

More utilities are developing guidelines for interconnection of DSGs with the grid. A number of national "model" guidelines are being developed by standard-setting committees for the Institute of Electrical and Electronic Engineers, the National Electric Code, the U.S. Department of Energy, and the Electric Power Research Institute, although none has yet released final versions and widespread utility endorsement is still uncertain. As a result, **DSG owners are likely to face different and sometimes conflicting interconnection equipment standards well into the 1990s. These differences may hamper both the use of DSGs as well as the standardized manufacture of interconnection equipment.**

Interconnection Costs

The costs of interconnection have declined dramatically in recent years, particularly for smaller DSGs. Typical costs range from $600/kW for 5 kW units to less than $100/kW for 500 kW or larger units. The interconnection costs for multimegawatt DSGs are only a small fraction of the total cost of the facility. While future technological advances in microprocessor controls and less costly nonmetallic construction could bring costs down even further, the major cost decrease is expected to come from volume production of equipment. As mentioned above, though, this volume production may be delayed until national model interconnection guidelines are agreed on for interconnection equipment.

REGIONAL DIFFERENCES

A particularly important factor affecting the relative advantages of new electric generating storage, and load management technologies is the region in which a utility or prospective nonutility power producer is located. U.S. regions differ markedly in industrial base, demographic trends, and other factors affecting electricity demand; the age and composition (particularly fuel use) of existing generating facilities; the nature and magnitude of available indigenous energy resources; regulatory environment; transmission infrastructure and prospects for bulk power transfers; and other factors affecting the selection of electric power technologies.

Existing Generation Mix

The regional mix of existing generating facilities is likely to profoundly affect the relative attractiveness of new generating capacity. While most electric utility systems with substantial oil and gas capacity are expected to decrease use of these fuels over the next decade, **reliance on these fuels is expected to be strong enough in some areas, i.e., New England, the Gulf and Mid-Atlantic States, the Southeast, and the West, that the economics of competing technologies will remain particularly sensitive to the price and availability of oil and gas.** This will apply even more strongly in the few States such as Florida where, due to expectations of high demand growth and continued decreases in (or stabilization of) oil prices, utility systems are actually forecasting increased use of oil.

in California oil- and gas-fired generation, while declining, is projected to remain above 33 percent of the total electricity generation in the State through the end of the century (oil alone will be IS percent). Similarly, if present trends continue in Texas, oil and gas is projected to account for 35 percent of total generation and about so percent of total capacity over the same time period. In both States, high avoided cost rates resulting from continued reliance on oil and gas enhances the attractiveness of cogeneration, in particular, while the favorable tax climate in California enhances the attractiveness of renewable power generation projects initiated under PURPA. **In some States where oil and gas are the dominant fuels, especially California, Louisiana, and Texas, cogeneration may constitute a significant fraction of total installed capacity by the end of the century.** Some utilities in Texas, for example, are already planning for cogeneration contributions of as much as 30 percent.

The age of existing power generating facilities varies widely among U.S. regions. As a result, the prospects for life extension and plant rehabilitation vary as well. For example, Texas, the Southeast, and the States west of the Rockies will have the highest percentage increases in plants that would be logical candidates for such options between now and 1995, i.e., those generating units that will have been in operation more than 30 years. in terms of total installed capacity, the opportunities for life extension will be greatest in the Mid-Atlantic, Southeast, Gulf, and Western States. Site-specific economics will determine actual implementation levels.

Interregional Bulk Power Transactions

It appears that existing interutility and interregional transmission capabilities are being nearly fully utilized in the United States. Hence, the prospects for large increases in bulk power purchases among utilities using existing transmission capabilities will be limited. **Some regions,** however, such as portions of the West and Midwest, **are continuing to expand generation and transmission facilities in anticipation of serving the bulk power markets.** In addition, major transmission projects are underway in New York, New England, the upper Midwest, and the Pacific Northwest to allow these regions to purchase lower cost hydroelectric power generated in Canada from existing and proposed facilities.

Load Management

OTA has found that the prospects for increased load management in future utility resource planning vary by region. Perhaps more importantly, they also vary significantly by utility within reliability council regions. Moreover, utilities' objectives for pursuing load management vary as well. For example, utilities with very high current or anticipated reserve margins (many in the Midwest), are interested in load management to better use existing base load capacity, i.e., to stimulate increased demand in off-peak periods. Other utilities with very low current or anticipated reserve margins are pursuing load management primarily to reduce peak demand and defer the need for new capacity additions. Municipal utilities and rural cooperatives, which accounted for most of the points controlled by load management in 1983, are expected to continue to provide a strong load management market in all regions through the 1990s.

Reliability Criteria

An important indicator of a region's need for new generating capacity is reflected in measures of projected power system reliability. Such measures include the reserve margin—i. e., amount of installed capacity available in excess of the peak load, traditionally expressed as a percentage of the total installed capacity. Reserve margins, as well as other reliability measures, are sensitive to demand predictions, scheduled capacity additions and retirements, and other factors such as scheduled maintenance and adjustments for forced outages or firm power purchases and sales from other utilities.

The anticipated reserve margins over the next several decades vary considerably by region. Under medium demand growth (2.5 percent average annual growth through 1995), reserve margins are expected to dip as low as 15 percent (in the upper Midwest in the early 1990s) and peak as high as 47 percent (in the West in the mid-1980s). Under higher demand growth, power pools in all regions may fall below acceptable reliability levels in the early 1990s. Under low demand growth (less than 2 percent), reliability levels are likely to be adequate in all regions through the early 1990s.

Renewable Resources

Increased use of solar, wind, and geothermal resources in U.S. electric power generation will vary regionally due to both the relative cost of alternative generation and the availability of high-quality renewable resources. For example, while wind regimes are promising for wind turbines in many areas across the country, they are currently being deve!Gped mostly in California where high utility avoided cost and a favorable tax climate have encouraged their development in nonutility power production applications under PURPA. In addition, a State-sponsored wind resource assessment program has spurred development. A similar situation exists for photovoltaics and geothermal power, although geothermal development is much more regionally limited to the West. Solar thermal power generation, for the next several decades at least, may be viable only in the Southwest and perhaps the Southeast where solar insolation characteristics may be sufficient to make projects competitive and where land availability is not a major constraint on development.

UTILITY AND NONUTILITY INVESTMENT DECISIONS

Prior to the 1970s, maintaining power system reliability was treated as a prescribed constraint and utilities had little difficulty earning their regulated rate of return on investment while achieving steady reductions in the cost of electricity by building larger, less capital-intensive powerplants, Hence, utility decision making objectives of maintaining service reliability, maximizing corporate financial health, and minimizing rates could generally be pursued simultaneously.

Because of the complex and uncertain investment decision environment that has evolved since the 1970s, utilities have begun to consider offering varying levels of service reliability and to more sharply weigh trade-offs between stockholders' and ratepayers' interests in making new plant investment decisions. **In many instances, utilities are avoiding making large-scale plant commitments and, indeed, are considering the host of options cited earlier that can defer the need for such commitments.**

Utility Investment

of particular interest to many utilities are the potential benefits of increased planning flexibility and financial performance offered by small-scale, short lead-time generating plants. For example, OTA **modeling studies indicate that with uncertain demand growth, the cash flow benefits of such plants can be considerable.** This is true, in some cases, even when the capital cost per kilowatt of the smaller plants is as much as 10 percent more than for large plants. In addition, the corresponding revenue requirement under a small plant scenario can be lower over a 30-year period.

Electric utility efforts to exploit these financial benefits and nonutility interest in exploiting potentially attractive investment opportunities under PURPA have already stimulated considerable interest from both types of investors in smaller scale generating technologies. **Other benefits are important as well, including less environmental impact, less "rate shock" to consumers by adding generating units to the rate base in smaller increments, increased fuel diversity, and reduced transmission requirements if generating units can be sited closer to load centers.**

Most of the generating technologies considered in this assessment offer the small-scale modular features attractive to many utilities as a means of coping with financial and demand uncertainties. This is likely to make the long-term prospects of these technologies very bright, **Despite this long-term promise, however, in most regions for the next 10 to 15 years most of the new generating technologies are not likely to be competitive with other often more cost-effective strategic options cited earlier–life extension and** rehabilitation of existing generating facilities, increased purchases of power from other systems, and intensified conservation and load management efforts.

Nonutility Investment

Nonutility interest is likely to continue to be limited for the most part to more mature technologies that can be implemented in cogeneration applications or can qualify for favorable tax treatment, e.g., combustion turbines, wind, and more recently AFBC.

Investors in nonutility power projects seek to maximize the risk-adjusted return on their invested capital. Depending on the type of investor, other considerations are important as well including tax status, timing of the investment, cash flow patterns, and maintenance of a balanced portfolio of investments with varying risk. In order to finance a new nonutility project, the major risks (technology, resource, energy price, and political) must either by mitigated or incorporated in contingency plans. Common risk reduction techniques used to date include vendor guarantees (or having the equipment vendor take an equity position in the prospective venture) or take-or-pay contracts with utilities.

CURRENT AND FUTURE STATE OF ALTERNATIVE TECHNOLOGY INDUSTRY

Many of the new generating technologies considered in this assessment are being developed by a much wider range of firms than has traditionally dealt with the electric utility industry. Moreover, many firms involved in deploying some new technologies, to the extent that they are being deployed, are small independent firms, less than 3 years old. For example, the wind industry's equipment sales have for the most part been to third-party financed wind parks selling power to utilities under PURPA; many of these parks have been developed by the wind manufacturers themselves. Other developers are large aerospace, petroleum, or other companies that have also not traditionally dealt with electric utilities, and many of them are only beginning to develop working business relationships with them.

Most of the technologies considered in this assessment are in a transition phase of their development, i.e., between pilot- and commercial-scale demonstrations or early commercial units. Some of these technologies are progressing through this transition aided by the existence of auxiliary markets (in many cases foreign) other than the grid-connected power generation market. For example, small-scale AFBC technology has matured in the industrial marketplace, primarily in process heat applications. Similarly, while the PV technology that will ultimately begin to penetrate grid-connected power generation markets is not yet clear, the various candidates (flat plate, amorphous silicon, concentrators, etc.) are maturing in other markets such as consumer electronics or remote power applications.

As most of these technologies mature and the relationships of vendors and manufacturers with utilities and nonutility power producers develop, the nature of negotiated agreements between the parties initiating commercial demonstrations or early commercial units may dictate the pace of commercial deployment of the technologies. In particular, **the allocation of risks in the form of performance or price guarantees or other mechanisms will be especially important for the electric utility market.** For example, an equipment manufacturer's agreement to hold an equity position in early commercial projects might be viewed by many utilities as an adequate performance guarantee.

One of the problems facing increased deployment of some new generating technologies in the

1990s, as mentioned earlier, was that of potential delays in lead-times of early commercial projects. While the features of smaller scale and modular design for many of these technologies offer ultimate promise for very short lead-times, **experience to date indicates that the rate of deployment of some new generating technologies is being lowered because lead-times being experienced by early commercial projects have been longer than anticipated, partially due to the time needed to complete regulatory reviews.** As regulatory agencies become more familiar with the technologies, the time to complete such reviews should decrease, although this is by no means guaranteed as evidenced by the history of other generating technologies.

The pressures of competition from foreign vendors, many of whom are heavily 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, and the pending changes in favorable tax treatment throw into doubt the continued commitment of U.S. firms who are currently developing these technologies. For some technologies, such as wind turbines, solar thermal-electric technologies, and photovoltaics (at least those focusing on concentrator technologies), the survival of some domestic firms may be at stake. Many domestic firms may not be able to compete in world markets over the next decade. However, in some cases foreign markets are considered to be interim markets for technologies as they mature to the point where they can compete in the U.S. grid-connected power generation market.

FEDERAL POLICY OPTIONS

Accelerated demand growth, coupled with current problems in building conventional, central station powerplants, could lead to serious difficulty in meeting new demand in the 1990s. **As a result it may be prudent to ensure the availability of an array of new generating technologies.** Then, the buyers in the market for generating technologies will have a broader range of technologies from which to choose. To ensure this **availability** will probably require a sustained Federal involvement in the commercialization of new electric power generating, storage, and load management technologies. The most logical goals for the Federal initiatives are:

- reduce capital cost and performance uncertainty,
- encourage utility involvement in developing technologies,
- encourage nonutility role in commercializing developing technologies, and
- resolve concerns regarding impact of decentralized generating sources (and load management) on power system operation.

The first three are primary goals while the fourth is less critical although still important. The relative importance of these goals as well as the efforts to achieve them are at the center of the debate over future U.S. electricity policy. A range of possible initiatives is summarized in table 2-4 along with the Federal actions that would most likely be required to implement them.

Research, Development, and Demonstration

Perhaps foremost among the options necessary to accelerate technology development is a sustained Federal presence in research, development, and demonstration of new electric generating and load management technologies. While **most of these technologies are no longer in the basic research phase, development hurdles are still formidable and the importance of research, development, and demonstration remains high; if these hurdles are overcome the result could be a quick change in competitive position for many of these technologies.** For example, proof of satisfactory reliability during a commercial utility-scale demonstration of AFBC could substantially accelerate its deployment among electric utilities. As noted, the technology already is beginning to be deployed very quickly in smaller scale commercial cogeneration applications.

Table 2-4.—Policy Goals and Options

Reduce capital cost, improve performance, 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 and/or preferential avoided energy cost calculations under PURPA
4. Standardize interconnection requirements

Encourage increased utility involvement in developing technologies:
1. Increase utility and public utility commission support of research, development, and demonstration activities
2. Promote involvement of utility subsidiaries 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 critical milestone in utility or nonutility power producer acceptance of new technology is completion of a successful commercial demonstration program. The utility decisionmaking caution cited earlier confers added importance to advanced commercial demonstration projects, While there is considerable debate in the industry over what constitutes an adequate demonstration, two basic categories are often 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 nonlaboratory 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. Generally, activities in the first category are necessary for demonstrating commercial viability and activities in the second category are necessary for accelerating commercializat ion.

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 of equal importance. Among the most successful demonstration ventures have been and are likely to continue to be cooperative ventures between industry (manufacturers and either utilities or nonutility power producers) and the Federal Government, with significant capital investments from all participants in the venture.** The current AFBC, IGCC, and geothermal demonstrations are good examples. In particular, **for larger scale technologies in utility applications, cooperative industry-government demonstration efforts, managed by the utilities, have a good track record.** For accelerated deployment, similar projects would be required for fuel cells, CAES, advanced battery technologies, and central receiver solar thermal powerplants.

The relationship between utilities and public utility commissions in early commercial applications of new generating and load management technologies is an important factor that will affect the deployment of these technologies in the 1990s. In particular, increased research, development, and demonstration activity will require utilities and utility commissions to agree on appropriate mechanisms for supporting such activities. Direct support alone from the rate base for research activities (e.g., as the allowance for contributions to the Electric Power Research institute) may be desirable and important, but they are not sufficient to assure extensive deployment of these technologies by the 1990s. **Much larger commitments that involve large capital investments such as 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 a 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 it, particularly if other utilities could benefit substantially from the outcome if successful and 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.

Other Policy Actions

In addition to maintaining a continued presence in research, development, and demonstration and implementing environmental policy affecting power generation, **several other Federal policy decisions affecting electric utilities could influence the rate of commercial development of new generating technologies over the next several years. These include removal of the Powerplant and Industrial Fuel Use Act (PIFUA) restrictions on the use of natural gas, and making PURPA Section 210 benefits available to electric utilities.** These steps could increase the rate of deployment of developing generating technologies, but their other effects will have to be carefully reviewed before and during implementation.

A more liberal power generation exemptions policy under PIFUA or an outright repeal of the Act could, in addition to providing more short-term fuel flexibility for many utilities, be an important step toward accelerated deployment of "clean coal" technologies such as the IGCC which can use natural gas as an interim fuel. Some new technologies such as CAES and several solar thermal technologies use natural gas as an auxiliary fuel and would require exemption from PIFUA.

Permitting utilities to participate more fully in the PURPA Section 210 benefits of receiving avoided cost in small power production is likely to result in increased deployment of small modular power generating technologies, particularly cogeneration. For example, utilities are currently limited to less than 50 percent participation in PURPA qualifying cogeneration facilities. In addition, with full utility participation in PURPA, ratepayers likely would share more directly in any cost savings resulting from these kinds of generating technologies. Allowance of full PURPA benefits for utilities, however, could cause avoided costs to be set by the cost of power from the cogeneration unit or alternative generation technology. Such avoided costs would likely be lower than if they were determined by conventional generating technologies as now is the case. Lower avoided costs would reduce the number of cogeneration and alternative technology power projects started by nonutility investors. Expanded utility involvement, though, may more than compensate for this decrease.

In relaxing the PURPA limitation potential problems require attention, including ensuring that utilities do not show preference for utility-initiated projects in such areas as access to transmission or capacity payments. Moreover, project accounting for PURPA-qualifying projects would probably need to be segregated from utility operations and non-PU RPA qualifying projects in order to prevent cross-subsidization which would make utility-initiated projects appear more profitable at the ratepayers' expense. These concerns can be allayed through carefully drafted legislation or regulations, or through careful State review of utility ownership schemes.

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, such proposals, if enacted, would almost certainly have an impact on new generation technologies. The experiences of PURPA and the Southwest Bulk Power Transaction Deregulation Experiment 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 generating units.

Renewable Energy Tax Credits

Along with direct support for research and development and joint venture demonstration projects, an important component of the Federal program for new generating technology commercialization has been favorable tax treatment through such mechanisms as the Renewable Energy Tax Credits (RTCs), the Investment Tax Credit (ITC), and ACRS depreciation allowances. **The RTC, in particular, coupled with recovery of full utility avoided costs (under PURPA) by nonutility power producers have been crucial in the initial commercial development and deployment of wind and solar power generating technologies. With declining direct Federal support for renewable technology development, the RTC has supported development of advanced and innovative designs as well as commercial deployment of mature designs. Without continued favorable tax treatment, deployment of solar, wind and geothermal technologies is likely to be slowed significantly—certainly in nonutility applications.** Without existing tax incentives, many of the mostly small firms involved in development projects will lose access to existing sources of capital. Even large, adequately capitalized firms may lose their distribution networks, making industry growth more difficult.

With favorable tax treatment, some new technologies, such as geothermal and wind, have become important sources of new and replacement generating capacity in the West and Southwest. However, they must compete with more mature, modular technologies, e.g., conventional cogeneration technologies. And these modular technologies will continue to account for an important share of the new generating capacity, in the form of both utility and nonutility owned (and perhaps joint) ventures.

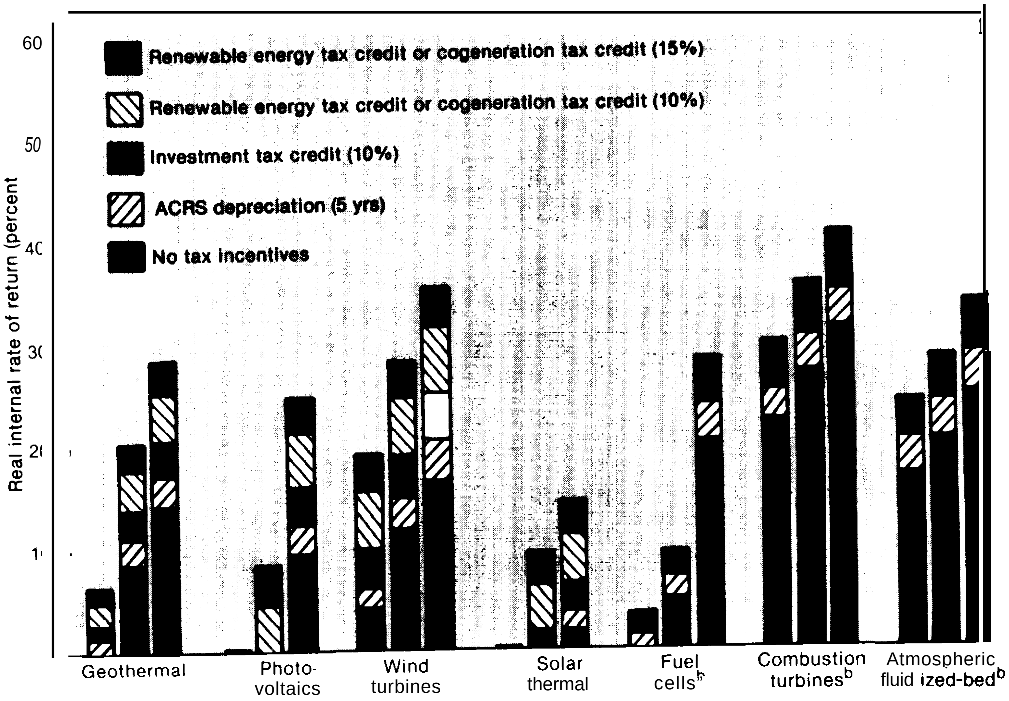
Figure 2-1 shows the cumulative effect of tax benefits, including accelerated depreciation allowances (ACRS), ITCS, and RTCs on the real internal rate of return for technologies considered in this assessment under the condition of nonutility ownership. (IGCC is not included in this figure since it is unlikely to be developed in nonutility power projects.) **The figure shows that the RTC may be crucial to the commercial survival of the renewable technologies with the possible exception of wind which may be mature enough to survive without these credits. The number of firms involved in wind technology development, however, would probably decrease markedly without these credits.**

The role of the RTC in accelerating commercial development seems to have changed. The original Federal policy was to provide direct research support to develop the technology and the RTC to accelerate commercial deployment. **With decreased Federal research and development support, the RTC appears to be supporting research and development in the field; this might partially explain the wide variation in performance of wind projects in recent years.**

A frequently proposed alternative to the RTC, in order to ensure performance of projects claiming a credit, is a Production Tax Credit (PTC) which provides benefits only with electricity production. OTA analysis of the PTC shows that geothermal and wind technologies benefit most from a PTC. **others such as CAES and the direct solar technologies are aided only by a very large PTC. Similarly, tax benefits tied to production discourages producers from testing innovative designs since, if the design does not perform as expected, no benefits will be realized.** Another potential problem with the PTC is that monitoring electricity production may be difficult, particularly in applications that are not grid connected.

Other actions cited earlier for stimulating development in new technology within electric utilities may be more effective than tax preferences. For example, the decrease in the levelized per kilowatt-hour busbar cost for the renewable technologies considered in this 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.

Figure 2-1.—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.