Renewable Energy Technology Evolution Rationales

INTERNAL WORKING DRAFT

October 5, 1990

Office of Conservation And Renewable Energy

U.S. Department of Energy

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On September 16, 1991, the Solar Energy Research Institute was designated a national laboratory, and its name was changed to the National Renewable Energy Laboratory.

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Preface

This report was developed by a team of national laboratory researchers, contractors and Department of Energy (DOE) technology program staff over the period March through October 1990 as part of the National Energy Strategy process. The purpose of the report was to provide consistent, explanatory and in-depth documentation of how renewable technologies can be expected to evolve over time. An early draft of the document was printed by the Solar Energy Research Institute in late August 1990, under the title *Renewable Energy Technology Evolution Rationales.* The contents were reviewed and revised and the *Internal Working Draft - October 5, 1990* (with the same title) was released by the Office of Conservation and Renewable Energy in early October 1990.

This published version is a reprinting of this October 5, 1990, *Internal Working Draft* with no changes, revisions, or updating of data. Some improvements for reader convenience such as clearer charts/graphs and corrections in figure titles were made. Researchers were not asked to provide updated or content-corrected material for this publication. The purpose of publishing this report at this time is to provide a wider distribution of the important information in the report and to more fully document the information that was available and used in the National Energy Strategy process.

The list of authors and reviewers who were actively involved in the development of the document is long and it would be very difficult to credit all those who worked on or contributed to the project. Therefore, we have not provided a list of contributing authors. However, we heartily thank those many researchers, contractors and program specialists who contributed their considerable time and efforts to this assignment.

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Section 1

SUMMARY OF THE TECHNOLOGY EVOLUTION RATIONALES

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(DRAFT)

SUMMARY OF THE TECHNOLOGY EVOLUTION RATIONALES

General

The National Energy Strategy (NES) process has highlighted the need for in-depth documentation of how individual renewable energy technologies are expected to evolve over time. For most technologies the expectation is that they will move toward lower cost and higher performance in the future. NES analyses have focused on two scenarios for this evolution. The first assumes that current levels of Federal support for R&D will continue into the foreseeable future. The second assumes that funding for R&D will increase, at least in the near- to mid-term. This document provides detailed justifications for the technology evolution projections for both funding scenarios.

The Technology Evolution Rationales are closely tied to the document entitled Renewable Energy Technology Characterizations, prepared by Science Applications International Corporation (SAIC) with substantial program and laboratory input. That report encompasses a great amount of detail and covers over 30 renewable and storage technologies. It includes cost and performance estimates for the 1990-2030 period by component and for the 10 federal regions. These estimates are provided for the Base Case assumptions about policy and R&D funding. The SAIC Technology Characterizationsare suggested readings for those who desire greater regional or component detail than is provided in this document.

Technologies Chosen

To move ahead with development quickly, 13 key technologies have been chosen for this initial rationale document. These technologies include the following 6 electric generating technologies, 2 transportation biomass fuel technologies, and 5 solar for buildings technologies:

Electricity	Biomass Fuels	Solar for Buildings
Biomass Electric	Ethanol	Active Water Heating
Geothermal-Hydrothermal	Methanol	Active Water and Space Heating
Hydropower		Passive Space Heating
Photovoltaic		Active Solar Cooling
Solar Thermal		Daylighting
Wind		

Technology Summaries

The purpose of this summary is to consolidate the key points of the individual Technology Evolution Rationales and to focus on the approach and logic of the individual technology sections. An effort was made to simplify complex stories and use a "bulletized" format that keeps words to a minimum.

Biomass Electric

General-Resource and Markets

- Biomass resources, including wood and municipal wastes, offer an abundant, renewable fuel source for electric generation.

- Only 3 quads of wood and waste are currently used for electric/energy generation out of an estimated 15 quads available by the year 2000.

- Energy crops offer the potential to increase significantly the amount of economic biomass.

- Industrial cogeneration markets offer significant opportunity for biomass along with the utility and independent producer markets.

Base Case Cost/Performance Curve:

- Conventional steam-electric power generation technologies are technically mature and can compete in markets where the cost of biomass (usually waste) is competitive with fossil fuels.

- The cost of a wood-fired, steam-electric plant in the 50 MW size range is about $1,600/kW with the resulting levelized cost of about 6 cents/kWh in 1989 constant dollars (if $2.00/MMBtu wood can be obtained).

- While minor improvements are possible, especially in the ability to burn wet or bulky biomass, the Base Case forecast indicates no significant improvement until after 2010 when biomass/gas turbine systems may become available.

Intensified R&D Cost Performance Curve:

- Integrated biomass gasification and gas turbines may offer an opportunity for cost/performance improvements over conventional steam technologies for an intensified R&D approach. However, this technology has not been thoroughly investigated to-date.

- With an integrated gasifier/steam-injected gas turbine (STIG), efficiencies can approach 33%, and economies of scale can benefit small industrial users (5 MW range) as well as utility-sized plants (50-100 MW).

- Biomass liquefaction can provide fuels for existing oil- or gas-fired, combined-cycle plants.

- Research gains are needed in the following areas to move the biomass turbine technology to commercialization:
  - Gasification and particulate removal
  - System demonstration on a reasonable scale
  - Systems analysis to select best combinations
  - Proving biocrude liquids as turbine fuels
- Research to achieve biomass energy crop goals of $2.00/MMBtu is required for these fuels to become competitive with fossil fuels.

Projected Cost/Performance Curve:

Figure 1 shows the Base Case and intensified R&D projected costs of electricity.

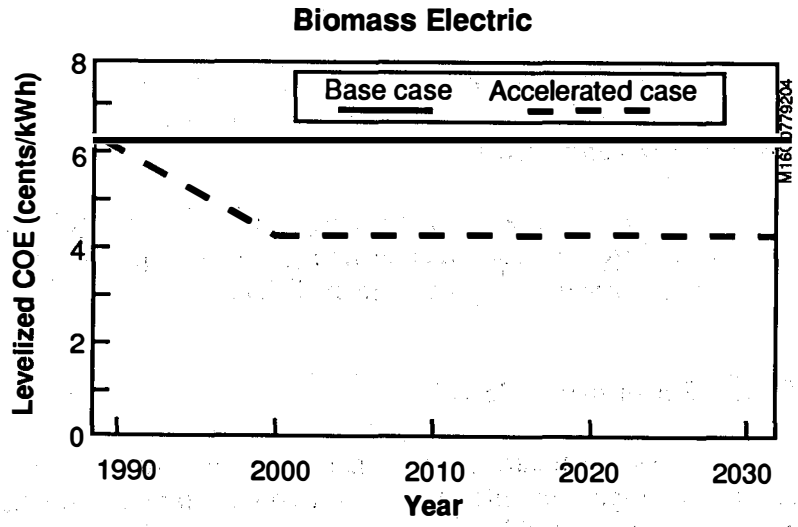

Figure 1. Biomass Electric Projected Levelized Cost of Electricity

<u>Geothermal-Hydropower</u>

General - Resource and Markets:

- Geothermal-hydrothermal technology uses either dry-steam, high-temperature liquids or lower temperature liquids that are tapped by drilling into accessible thermal reservoirs deep in the earth.
- The hydrothermal resource is primarily located in the western United States, with resource amounts available or economically recoverable still remaining fairly uncertain. Resources

identified by the U.S. Geological Survey (USGS) are in the 25 GW range, with unidentified resource estimates ranging from 100 to 300 GW.

- Geothermal-hydrothermal competes successfully in the utility baseload supply arena and currently provides about 6% of the electricity supply for the state of California.

Base Case Cost/Performance Curve:

- Geothermal-hydrothermal technology for dry steam and high-quality liquids is available and competitive today.

- The conversion technologies are relatively mature and have operated with high availability. The drilling technologies have progressed from their initial beginnings with oil and gas techniques to the current state of improved technology necessary for working the much more difficult geothermal resource.

- The greatest outstanding questions and impediments to development come from identification, management, and life of the thermal reservoir.

- Some unanswered questions still remain regarding conversion technologies and materials.

- The Base Case assumes continued research into and improvements in the following three areas:

  - Reservoir technology knowledge and practices (locating and managing reservoirs, well siting, injection techniques, etc.)

  - Drilling techniques (lost circulation control, rock penetration mechanics, and wellbore instrumentation)

  - Conversion improvements (more efficient cycles, new materials for handling fluids, and advancements in brine chemistry)

Intensified R&D Cost/Performance Curve:

- The major components of the intensified R&D Case would include the following:

  - Enhance exploration methodology or upgrade resource base reserves to 45 GW. By increasing reserves, the amount of economically recoverable geothermal energy can be increased.

  - Advance high-angle and core-drilling systems to further reduce hole-making costs.

  - Further reduce risks of exploration and reservoir management, thereby reducing the overall project risk.

Projected Cost/Performance Curves:

Figure 2 illustrates the Base Case and intensified R&D projected costs of electricity.

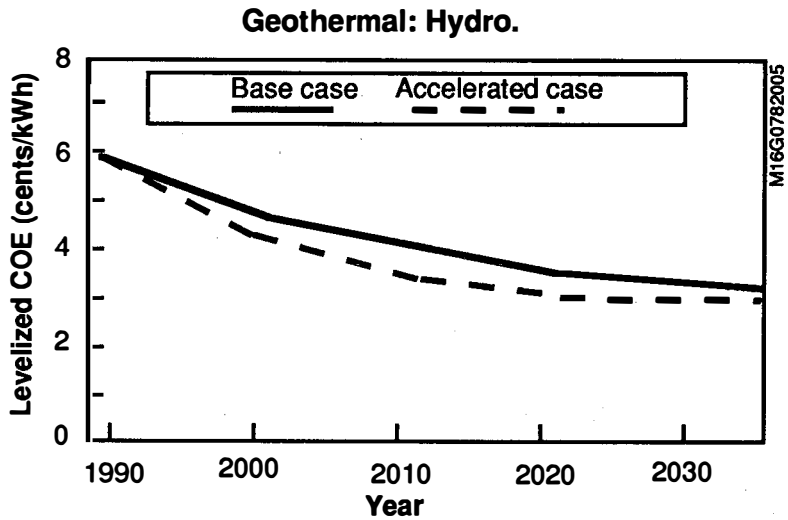

Figure 2. Geothermal-Hydrothermal Projected Levelized Cost of Electricity

Hydropower

General - Resource and Markets:

In the National Energy Strategy process, key issues concerning hydropower can be related to the following:

- **Potential** - How much capacity is available and at what type of site?
- **Cost** - What are the costs for expanded development?
- **Impediments** - What are the impacts of institutional and regulatory impediments?
- **Intensified R&D** - What are the impacts of intensified R&D?

To address these issues, a DOE-led team, including staff of the federal Power Marketing Areas, was established. This team began by identifying the amount of additional undeveloped hydro potential in the United States. The following highlights the preliminary estimate indicating:

- 61,200 MW of additional undeveloped potential
  - 32,700 MW at new dam sites
  - 18,500 MW at existing dam sites

10,000 MW by upgrading efficiency at existing plants

The resource assessment team is currently refining the resource potentials to include the costs by type of development.

In August 1990, DOE issued a report titled "Review of Impediments in Hydroelectric Licensing and Development in Support of the National Energy Strategy." This report addresses the institutional and regulatory impediments associated with licensing and includes recommendations for corrective action.

Base Case Cost/Performance:

The DOE team will be addressing the issue of cost, which historically has varied from site-to-site:

- Upgrades or refurbishment at existing sites can be less than $100/kW (less than 1 cent/kWh).

- Costs for new dams and facilities have been closer to $2,000/kW (4 to 6 cents/kWh).

Generally, costs have not been the inhibiting factor with hydropower. Environmental questions and the complex regulatory requirements have been the largest hindrance to expanded hydro development.

Intensified R&D Cost/Performance:

Under an intensified and accelerated R&D scenario, potentially developable hydro resources increase as the introduction of new technology makes new resources viable. Presently, there are 2 identified technologies:

- **Free-flow turbines** for use in fast-flowing rivers - added potential of about 12,500 MW.

- **Ultra-low-head and small-scale** sites - added potential of about 5,000 MW.

The accelerated R&D scenario also focusses on environmental and dam safety issues. Other general areas of research are important also:

- **Methodology for analysis of the cumulative environmental effects** would aid developments both in relicensing existing plants and in adding additional capacity.

- **Improved environmental performance,** such as dissolved oxygen or fish passage, would work to relieve environmental constraints.

- **Other research** to reduce capital costs, reduce O&M costs, increase efficiency, and improve safety is needed.

Photovoltaics

General - Research and Markets:

- Photovoltaic (PV) technology converts sunlight directly to direct current electricity.
- The total PV solar resource in the United States is large -- to provide 10% of the United States with PV electricity would use only 0.03% of the land area.
- The current markets for PV are consumer products and remote power supplies. Longer term markets are expected to be in the supply of bulk power for intermediate/peaking applications.

Base Case Cost/Performance Curve:

- Historically, PV has experienced significant cost reduction driven primarily by the rapidly falling cost of modules and cells.
- The Base Case cost/performance curve indicates current costs of about 30 cents/kWh dropping to the 4-5 cent range by 2030. The factors behind these projected cost reductions are:
  - Development of alternative, lower cost or higher efficiency designs (e.g., thin films and concentrators)
  - Ongoing module efficiency improvements
  - Development of new, lower cost manufacturing processes
  - Economies from large-scale manufacturing
- The credibility of these projections is enhanced by several factors:
  - Progress already achieved in the laboratory suggests continued cost reductions in commercial modules will be possible
  - Cutting the cost of thin-film PV modules in half is virtually assured as soon as they are manufactured on a reasonable scale.
  - The multiple pathways and technologies (e.g., thin films, concentrators, etc.) for approaching the cost goals increase the probability of getting there should one technology pathway run into difficulties.
  - In the long term, PV manufacturing costs will approach the cost of the material feedstocks, and will be dominated by such inexpensive materials as glass.

Intensified R&D Cost/Performance Curve:

- The first principal of accelerating PV development is to continue to enhance a balanced R&D program. Such a program consists of several aspects:
  - A core research and development program
  - Manufacturing research and development
  - Demonstration programs

Figure 3 illustrates the Base Case and intensified R&D projected costs of electricity.

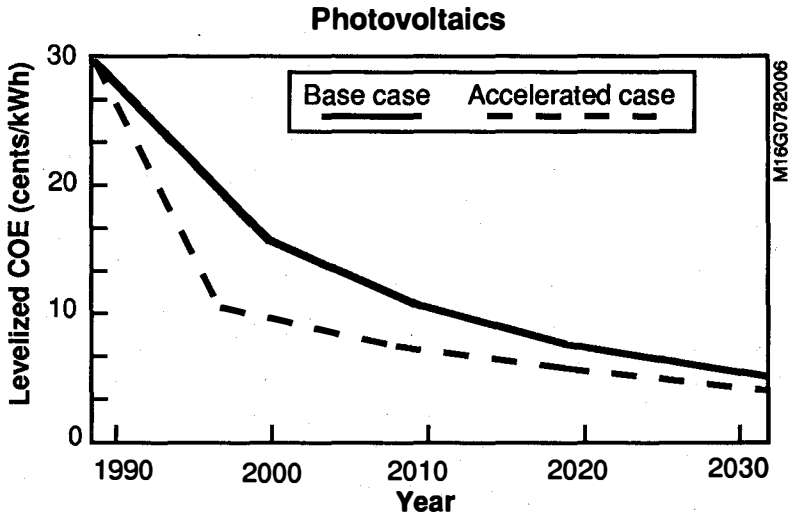

Figure 3. Photovoltaic Projected Levelized Cost of Electricity

Solar Thermal Electric

General - Resource and Markets:

- The solar thermal electric technologies convert sunlight to thermal energy and then to electricity. The three primary concepts used are (1) parabolic troughs, (2) central receivers and (3) parabolic dishes.
- The resource for solar thermal technologies is direct solar insolation, which is most prevalent in the Southwest or in other semi-arid regions of the world.
- The domestic utility market holds the major long-term opportunity for large-scale solar thermal systems.

Base Case Cost/Performance Curve:

- All three solar thermal technologies have been tested in industrial settings, and the trough technology is competitive for new supply in California.

- LUZ has installed and is operating 274 MW of parabolic trough capacity that use natural gas as a supplemental fuel. LUZ is planning to add 320 MW more of parabolic trough capacity by 1994 and 80 MW more per year until 2000.

- For the mid-term (around 2000) parabolic dish has lower cost than troughs; for long-term (2000-2007), central receiver systems promise lower costs than do trough hybrid systems.

- Key areas of expected technical advances include:

  - Lower cost collectors using stretched membrane concepts

  - Advanced receivers at lower cost

  - High efficiency Stirling engines for dish systems

  - Storage systems that eliminate supplemental fuel firing and increase capacity factors

Figure 4 illustrates the Base Case and intensified R&D projected costs of electricity.

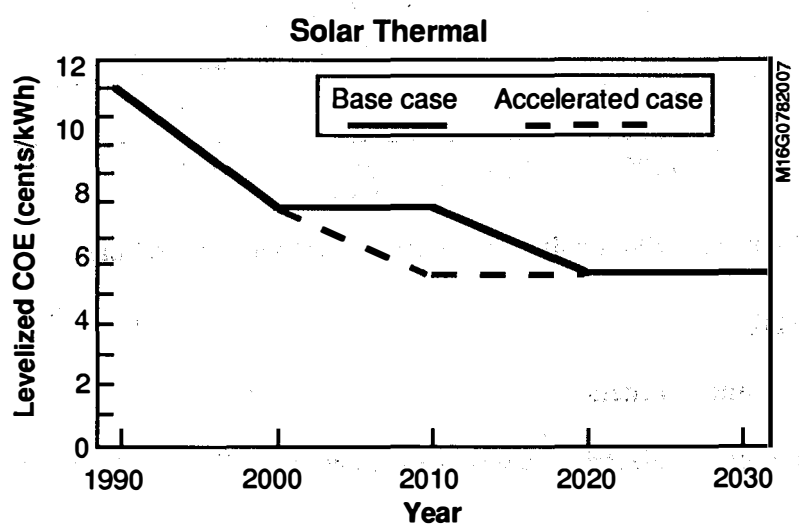

Figure 4. Solar Thermal Electric Projected Levelized Cost of Electricity

Intensified R&D Cost/Performance Curve:

- Federal cost sharing in the conversion of solar (10 MW) to nitrate salt and the construction of an advanced central receiver plant (30-100 MW) would reduce risk and advance the installation of economic 100-200 MW plants by about 10 years.

- Federal support of fabricating and testing dish/engine manufactured prototypes (20-50 units) using membrane dishes would advance the commercialization of this technology at least 5 years over the Base Case.

- For the mid-term (1997-2000) parabolic dish and central receiver systems promise lower costs than do trough hybrid systems.

Wind

General - Resource and Markets:

- Wind is a nondepletable resource that can provide significant quantities of energy to the nation.

- Good wind resources (approximately 13 mph annual average and higher) are available in most regions of the country.

- Utility supply markets are the most promising, with the better wind class sites being economic in the near- to mid-term and 13 mph sites becoming competitive in the longer term.

Base Case Cost/Performance Curve:

- From 1980 to 1990, the wind industry has reduced costs and improved performance by two to threefold.

- Commercially available wind turbines are the basis for estimates of cost and performance characteristics that are representative of 1990.

- These near-term advanced turbine designs are expected to take advantage of advanced structure and design codes; improve siting techniques; advanced airfoils, hubs and drive trains; taller towers; and advanced electronic and control systems.

- Long-term advances are expected in wind forecasting and characterization (atmospheric fluid dynamics), advanced rotors and controls (aerodynamics), structures and electrical systems and controls.

Intensified R&D Cost/Performance Curve:

- The intensified R&D Case would allow the advanced turbine designs to be completed by 1995 with a better opportunity for U.S. industry to meet the near-term market needs.

- The wind program would also address industry-related needs by working closely with industry in three areas:

- Research and testing to address and improve current operating difficulties
- Applications support for potential wind users
- Design advanced turbines by 1995 that can compete with conventional generation at 5 cents/kWh

Figure 5 illustrates the Base Case and intensified R&D costs of electricity.

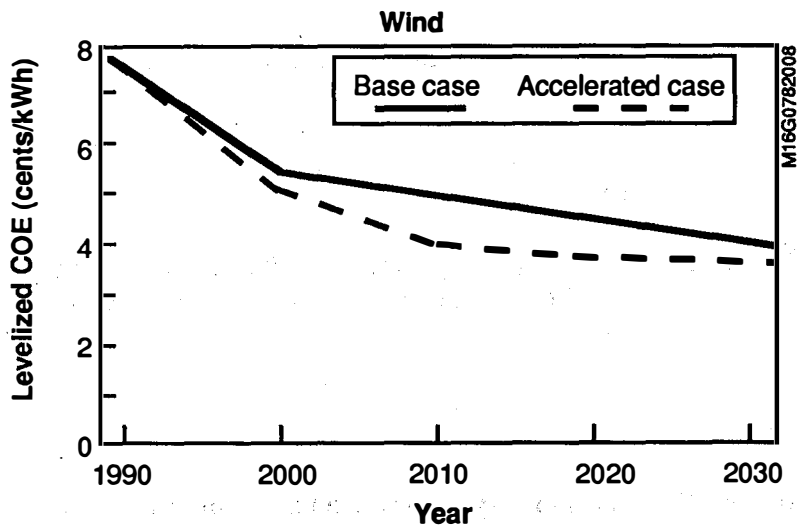

Figure 5. Wind Projected Levelized Cost of Electricity

Ethanol

General - Resource and Markets:

- Biomass is a renewable resource that can be converted into significant quantities of fuel ethanol to lower our nation's dependence on imported oil for transportation energy needs.
- Ethanol can also be beneficial in reducing urban air pollution, lessening the buildup of CO_2 and revitalizing the farm economy.
- While sugar and corn feedstocks can technically be used to produce ethanol, these have proved costly. The long-term potential of low-cost, cellulosic biomass holds promise in producing quantities of ethanol that can beneficially impact conventional supplies and the environment.
- Two major components of woody materials, cellulose and xylose, can be converted to sugar and then to ethanol. Lignin, the third component, can provide energy for the conversion process, or it can be converted to a beneficial additive.

- The major market for ethanol is in the transportation sector where ethanol can be directly blended with gasoline to form gasohol. It can also be transformed to an oxygenated fuel additive or burned directly as a replacement for automobile fuel.

Base Case Cost/Performance Curve:

- Fuel ethanol produced in the United States from corn totals approximately 850 million gallons annually. While technically viable, the use of corn requires a tax subsidy to be competitive.

- Cellulosic biomass hold greater potential than corn for large amounts of ethanol supply, but is naturally resistant to breakdown. Advances in "enzyme catalyzed processes" promise the most economical approach.

- Progress since 1980 indicates costs for production of ethanol from biomass have dropped from $3.60/gallon to the current $1.35/gallon.

- Under Base Case funding, and with expected limitations in industry-sponsored research, the introduction of technology for the production of ethanol from cellulosic biomass without subsidy will likely not occur until at least 2010.

Intensified R&D Cost/Performance Curve:

- To make ethanol from cellulosic biomass competitive with gasoline, substantial research progress must be accomplished on the following elements:

  - Research on Process Steps: Improve xylose and cellulose yields to over 90%, advance simultaneous production of sugars and ethanol, and improve use of lignins.

  - Integrated Process Testing: Improve performance of the overall process

  - Process Development Unit: Develop a larger scale plan to replicate equipment that would be used commercially

  - Engineering Development Unit: Develop a semi-commercial plant with government cost sharing

  - Supporting Research and Development: Study and analyze integrated production processes

  - Integration of Low Cost Feedstocks: Identify opportunities for less-plentiful, low-cost feedstocks

- The development of low-cost energy crops, a key component of ethanol development, is discussed under methanol.

Figure 6 illustrates the Base Case and intensified R&D projected costs transportation fuels.

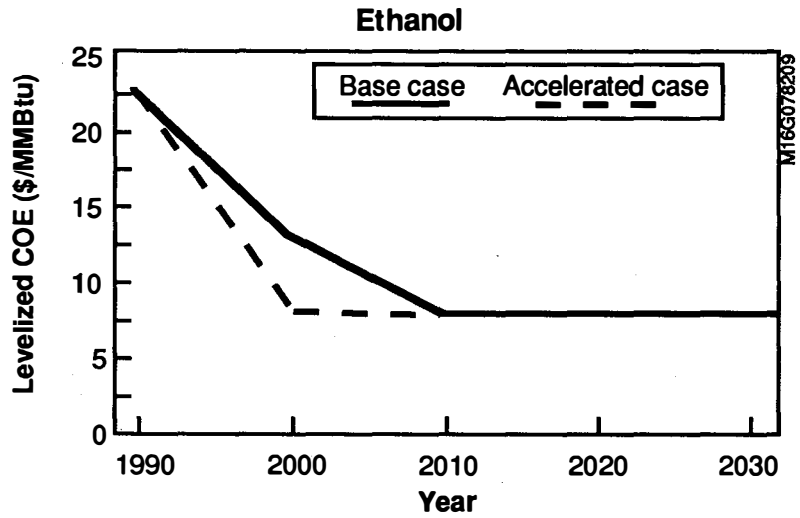

Figure 6. Ethanol Fuel Projected Cost of Fuel

Methanol

General - Resource and Markets

- The new growth market for methanol is projected to be the transportation fuel market, either as a direct substitute for gasoline or indirectly as an additive.

- Methanol fuel would use the same resource base as biomass electric and biomass ethanol, which are predominately wood and waste materials making up an estimated potential of 15 quads after the year 2000.

- Biomass energy crops offer a large potential for increasing the supply of biomass material, either in the form of wood or herbaceous energy crops.

Base Case Cost/Performance Curves:

Methanol

- The use of methanol from biomass is judged to be a nearer term option than the use of ethanol from biomass because its thermal chemistry is more conventional and the hardware is more developed.

- Limited R&D under the Base Case is assumed to focus on a demonstration plant to optimize gas composition and prove equipment reliability.

Energy Crops

- Advancements in the production of energy crops under Base Case assumptions are expected to be genetic improvements in selected number of species, improved harvesting, improved storage and handling equipment, and progress in analyzing economic and environmental issues.

Intensified R&D Cost/Performance Curve:

Methanol

- Process demonstrations, feedstock cost reductions, hot-gas cleanup, and single-pass methanol conversion show the greatest potential for cost reductions.

Energy Crops

- The intensified approach would increase the numbers of species of energy crops that would increase the geographic coverage to more marginal lands.

Active Solar Heating and Cooling

General - Research and Markets

- Active solar technologies convert sunlight to thermal energy which can be used to heat water, provide space heating, or as a source for heat activated cooling and dehumidification equipment.

- Solar energy represents a large resource, with geographical variations on the order of a factor of 2 within the continental U.S. The most favorable regions are located in the Southwest.

- The residential water heating market represents the best near-term opportunity for active solar technologies, although combined space and water heating applications, and cooling applications show promise.

Base Case Cost/Performance Curves

- Modest cost reductions (in constant dollars) have been realized for active solar technologies over the last decade. Since the mid 1970's collector performance gains of 35% have been realized in commercial products.

- Commercially available systems are the basis for the 1990 estimates of cost and performance.

- Advances in the near-mid term are based on improvements in control strategies and system integration for active solar water heating and combined water heating and space heating

systems. In addition, cost reductions due the lower cost distribution and storage components are anticipated. For active solar cooling systems, improvements in the thermal coefficient of performance (COP) of desiccant dehumidifiers, coupled with similar improvements cited above for water and space heating systems is anticipated.

- Long-term advances include substantial reductions in solar collector costs due to the use of lower-cost, light-weight materials. In addition, further advancements in desiccant dehumidifier COP (double that of current technology) are anticipated.

Intensified R&D Cost/Performance Curves:

- The intensified R&D case would result in an acceleration of the time-frame for attainment of the cost-of-energy estimates as shown in Figure 7.

- The increased federal funding would be directed at an expanded materials research effort, system studies to optimize solar collection, storage, and distribution , and joint efforts with industry to improve reliability and accelerate technology transfer.

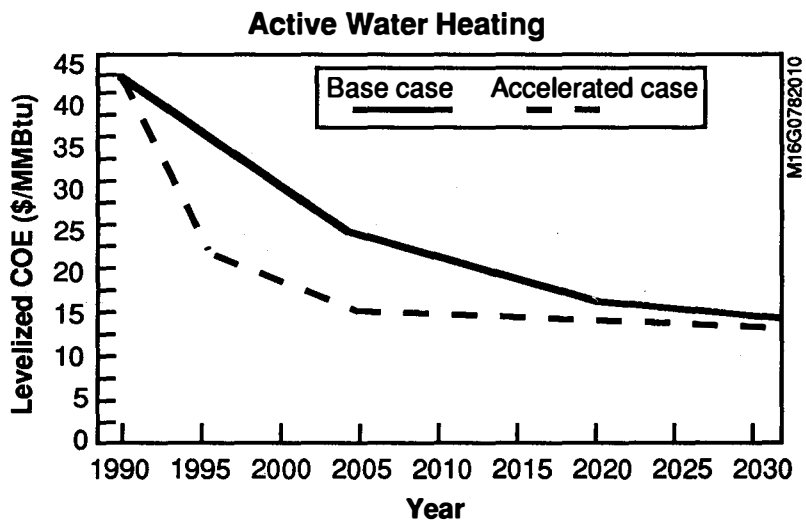

Figure 7. Active Water Heating Projected Cost of Energy

Passive Solar Heating

General - Resource and Markets

- Passive solar heating systems capture and convert sunlight to useful thermal energy by using properly oriented windows (for collection) and interior materials such as walls and floors for thermal storage. They rely primarily on natural convection and radiation for heat distribution.

- The solar resource for passive solar heating is large, with the greatest availability in the southwest and the least in the northeast and coastal regions of the pacific northwest.

- Passive solar heating technology is primarily incorporated into new in residential buildings today.

Base Case/Performance Curve:

- Passive solar systems can vary widely in cost depending on building architecture. Typical systems range from no additional costs to a few percent of a building's construction costs.

- A moderate energy contribution, direct gain passive solar heating system is the basis for the estimates of cost and performance that are representative of 1990.

- Anticipated improvements in the near-mid-term include reduced storage costs (additional storage in the form of masonry is generally required for moderate to higher energy contribution systems) due to the introduction of low-cost, high heat capacity materials such as phase change material (pcm) impregnated wallboard.

- In the long-term, the use of high thermal resistance, high transmittance glazings will increase energy contributions and reduce delivered energy costs.

Intensified R&D Cost/Performance Curve:

- The increase in federal funding would support additional research on thermal energy storage and advanced glazings. It would enable full scale testing in buildings in cooperation with the buildings industry. It would also enable the development of the necessary design information to increase utilization by homebuilders and the design community.

- The intensified R&D case would allow earlier introduction of pcm/wallboard and advanced glazings in the marketplace.

Figure 8 illustrates the Base Case and Intensified R&D costs of energy.

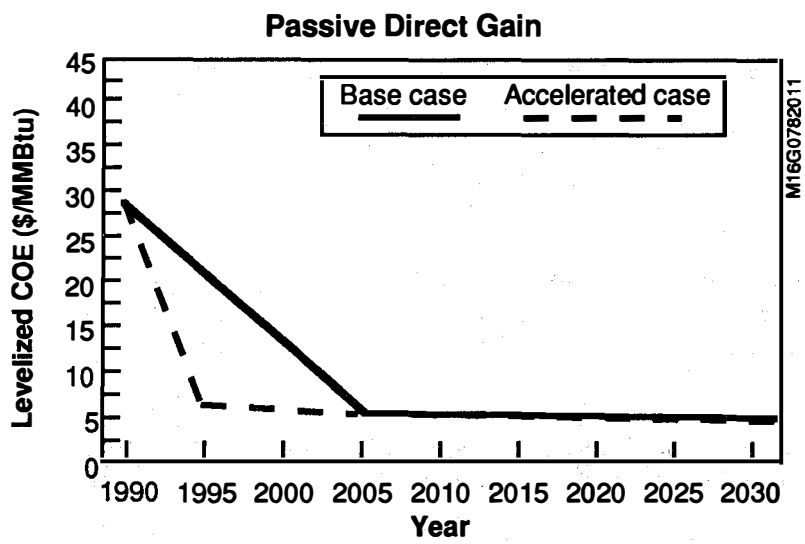

Figure 8. Passive Direct Gain Levelized Cost of Energy

Daylighting

General - Resource and Markets:

- Daylighting technologies make use of building architectural elements to increase the availability of natural light in building interiors. By properly integrating electric lighting with daylighting sensor controls, the amount of electric lighting required can be considerably reduced.

- Daylight refers to the visible portion of the solar spectrum and is widely available throughout the year; even in the cloudiest regions of the U.S. Adequate resource exists under overcast sky conditions to meet a substantial portion of building lighting requirements.

- The greatest market for daylighting technologies is in the nonresidential buildings market.

Base Case Cost/Performance Curve:

- Daylighting technologies currently available use conventional glazings in view windows, skylights, and roof monitors. Architectural features such as light shelves are also used to direct more light into a building's perimeter.

- The basis for the near-mid term cost estimates are for a prototype electrochromic window that can modulate the intensity of sunlight in response to comfort or energy requirements. This enables adequate light transmission while controlling heat gains and losses. Energy savings are achieved by reducing electric energy requirements for lighting based on daylight availability. No such product is currently on the market, therefore no 1990 data point is shown in Figure 9.

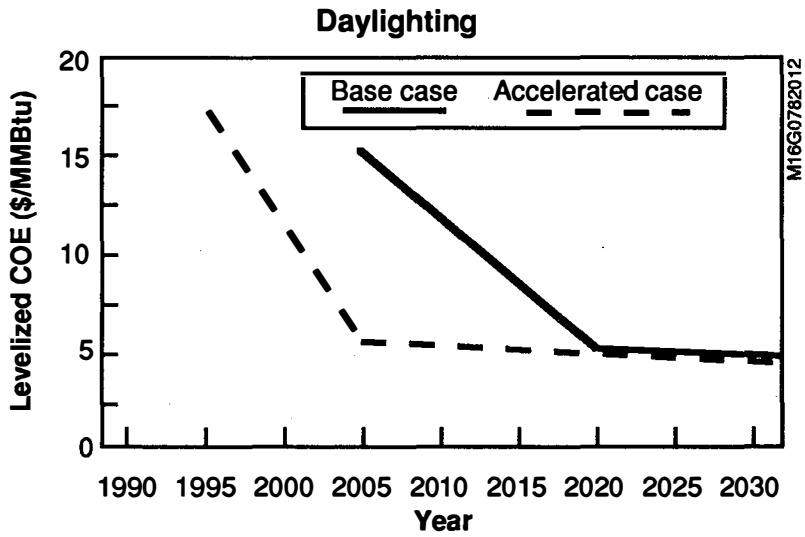

Figure 9. Daylighting Levelized Cost of Energy

- The long-term advances are based on the mass production of electrochromic windows with improved optical transmittance range.

Intensified R&D Cost/Performance Curve:

- The intensified R&D Case would allow introduction of competitive electrochromic windows within the next 15 years, and enhance U.S. prospects for maintaining leadership in this technology.

- The increased federal funds would be used to broaden materials research efforts on electrochromic materials, and the development and testing of large prototypes.

Section 2

TECHNOLOGY EVOLUTION RATIONALE FOR BIOMASS ELECTRIC TECHNOLOGY

October 5, 1990

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BIOMASS SYSTEMS ELECTRIC TECHNOLOGY RATIONALE

1.0. INTRODUCTION

1.1 Technology Description

Biomass resources including wood, energy crops, and municipal wastes, offer an abundant, renewable fuel source for electric generation. Like fossil fuels, biomass is burned to provide heat to a working fluid, such as steam. The working fluid provides power to drive electric generators. An important environmental feature of the biomass technology is the recycling of carbon in the feedstock growth process. Unlike the burning of fossil fuels, biomass combustion recycles the carbon fixed by photosynthesis in the growth phase.

At present, all biomass electric systems are of the conventional, steam-driven type. Biomass is burned to provide heat for a boiler. The steam which is generated under pressure in the boiler is subsequently fed to a steam turbine to provide shaft power for electric generation. A conceptual process flowsheet is shown in Figure 1. Similar technology is used to produce electric power from fossil and petroleum fuels. Advanced technologies such as fluidized bed combustors are also allowing other feedstocks, including wet wastes, to be used at high efficiencies in steam generation systems. In addition, a number of newer concepts such as biomass gasification, liquid-fueled gas turbines, and steam injected gas turbines are potential future technologies that will be discussed later in this document.

1.2 Technology Application/Users

The electricity produced from biomass is dispatchable rather than intermittent in nature and is thus available to utilities on a demand basis. Some 8 Gigawatts (GW) of biomass energy based generating capacity exists in the United States today, primarily owned and operated by industrial entities.[1] Perhaps because of the smaller scale and cogeneration opportunities of many biomass operations, utilities have not been major developers of biomass-based plants. To date, utilities

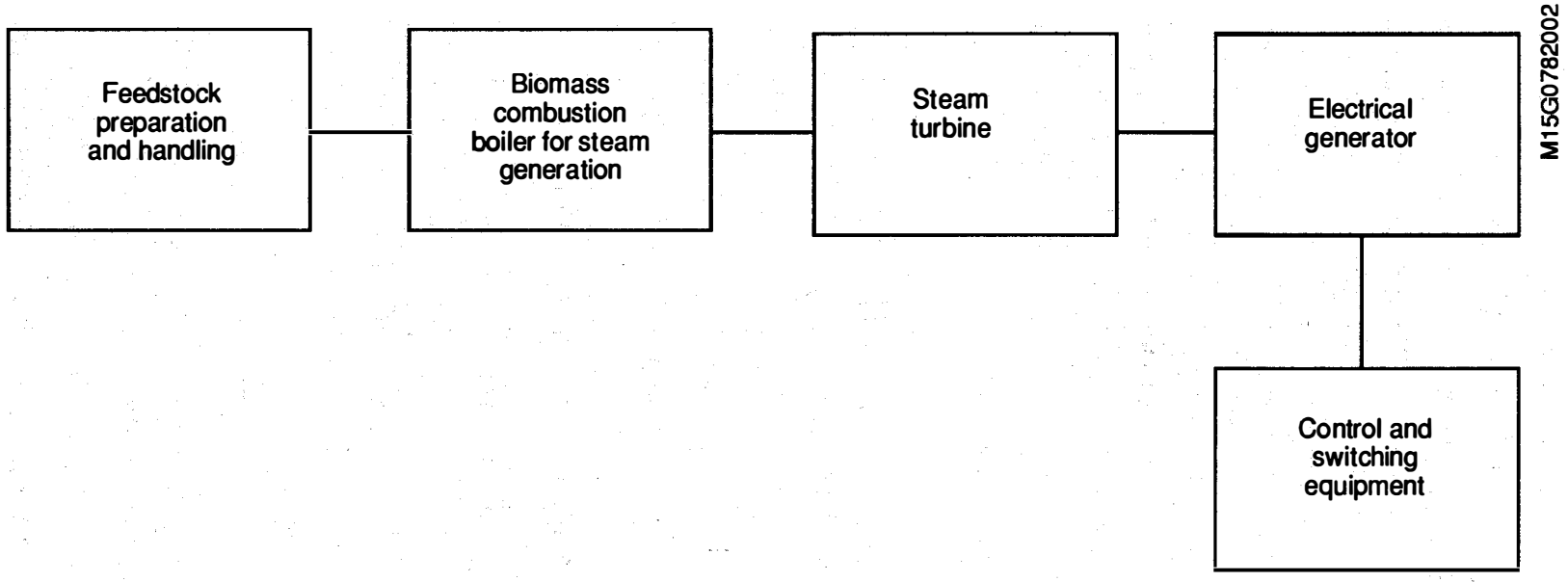

Figure 1. Conventional Biomass/Steam Systems Conceptual Process Flow Sheet

have been involved in only a handful of dedicated wood-fired plants in the 40 to 50 megawatt (MW) size range, and in some firing of municipal solid waste (MSW) in conventional fossil plants. In 1989, almost 8000 MW of nonutility-owned, grid-connected, biomass-based generation capacity was operating. Of this, more than 70% was in cogeneration systems. Wood-fired systems accounted for 77% of the total capacity followed by MSW (11%), agricultural waste (7%), landfill gas (4%), and digesters (1%). A significant amount of remote, nongrid-connected, wood-fired capacity also exists in the wood products industry. The present biomass generation capacities by state and by feedstock are shown in Figures 2 and 3.

Since 1987, the increase in MSW-fired facilities has been particularly rapid, growing by 70% to over 1600 MW in 1989. There are currently about 160 waste-to-energy facilities in the United States. Most of these are mass-burn facilities where MSW is combusted as received without any separation. Increases in the numbers of MSW facilities will face considerable public scrutiny. Waste managers seeking to build new facilities or desiring to expand existing ones encounter concerns with emission controls, solids disposal, and the problem known as NIMBY--"not in my backyard." Public opposition directed at landfills, waste-to-energy facilities, and resource recovery facilities is difficult to overcome. The opportunities for MSW will therefore depend highly on public acceptance and resolution of concerns about emissions and solids disposal. However, the high tipping fees for waste disposal which may be available in the future may provide significant financial incentive for industry.

In the future, if assured supplies of low-cost (about $2.00/MilBtu) biomass can be provided to utilities or independent producers, additional biomass-fueled generating capacity is likely to be installed in locations near the supplies. Reductions in transmission and distribution investments, achieved by placing power plants closer to the outlying loads of utility systems, are likely to be a significant incentive. Also,

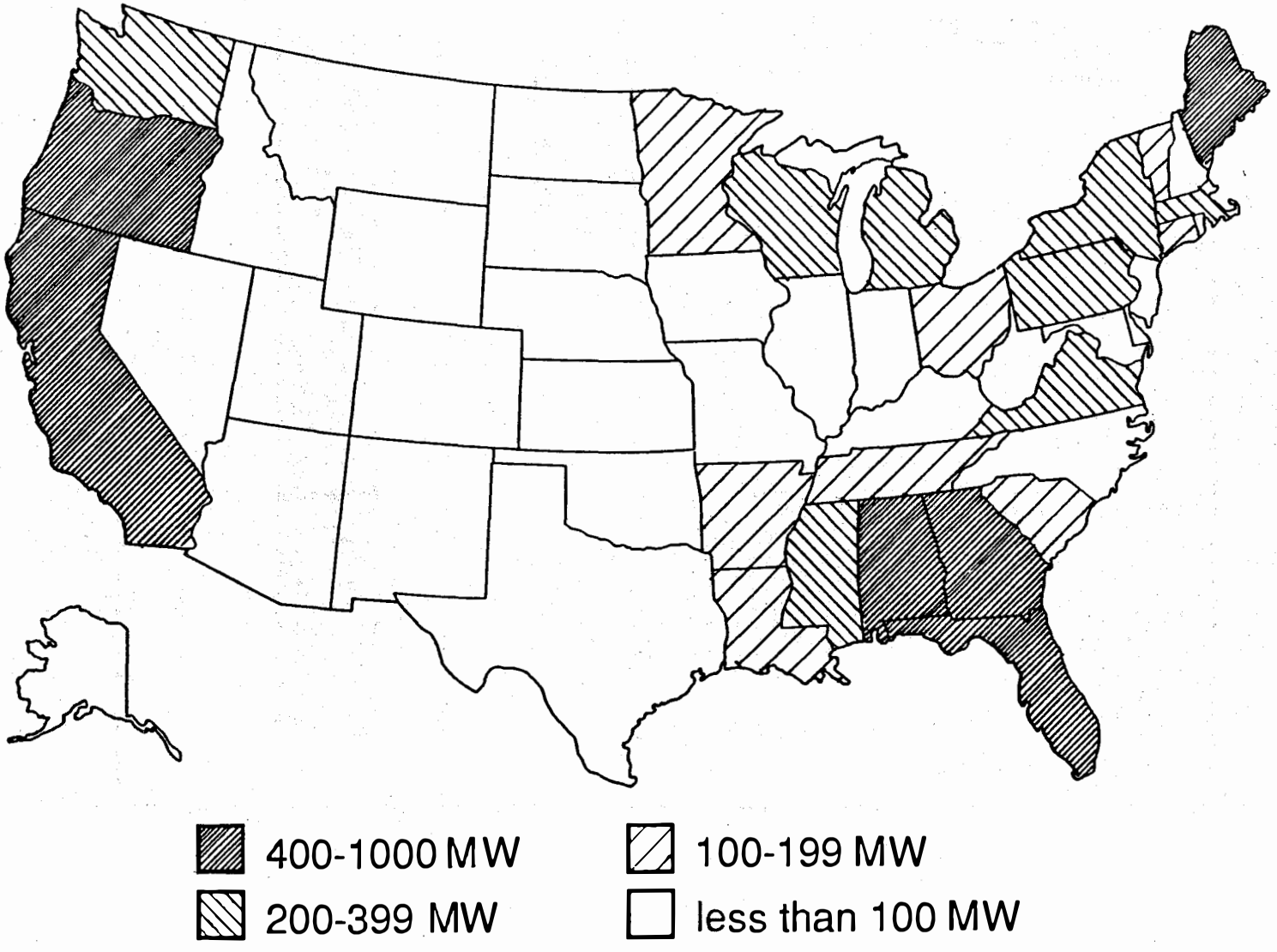

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Figure 2. Biomass Electric Generation Capacity by State—1989

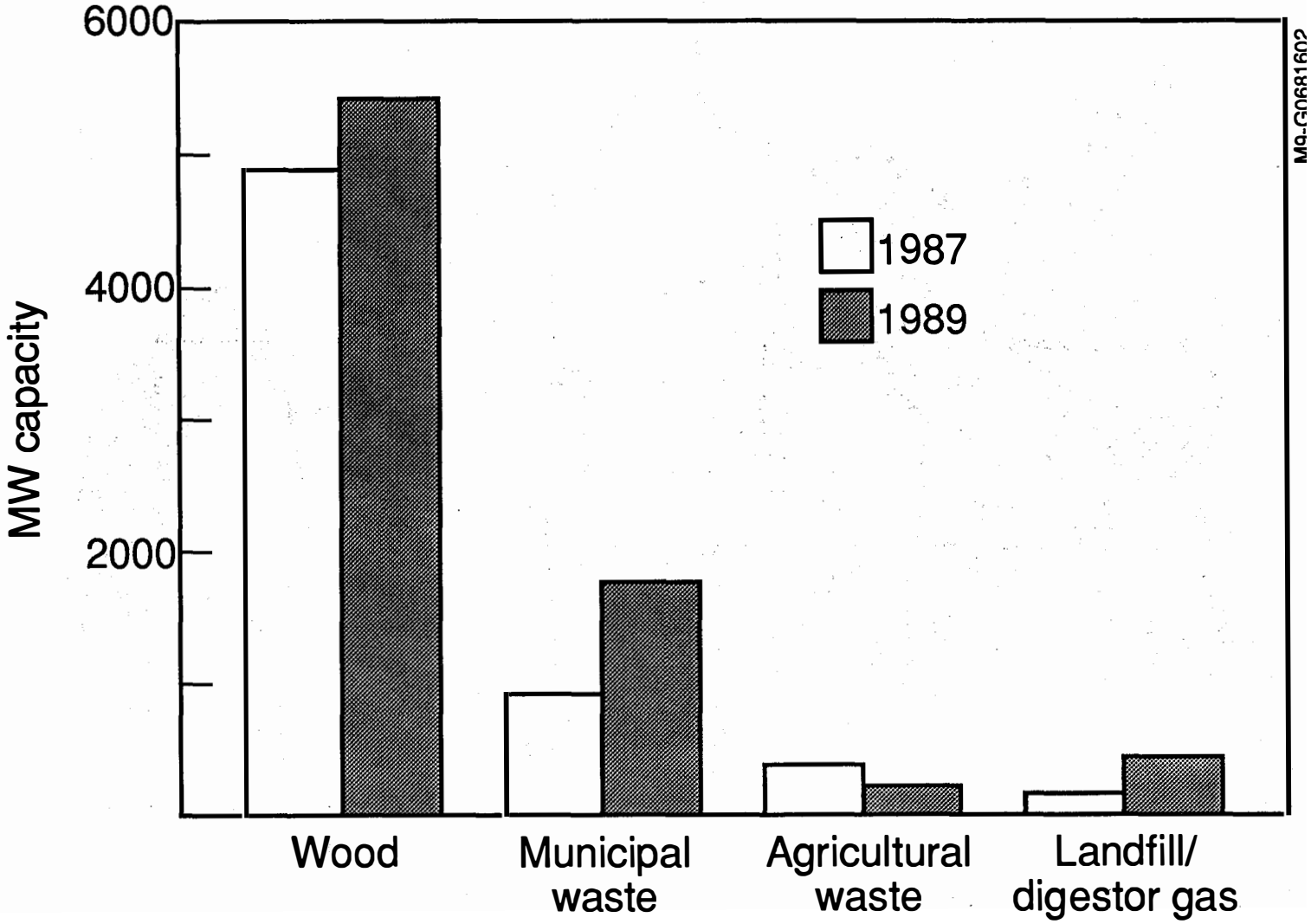

Figure 3. Biomass Electric Capacity by Feedstock

utilities having problems securing approval of economic sites in urban areas may look to wood-fired plants as one alternative. New England, in particular, has potential wood supplies available and, as a region, may need base-load or mid-range capacity in the next decade or two.

In the future, the combination of industrial and utility interest is expected to continue. Regardless of which sector actually develops the capacity, the electricity which is produced will still largely be grid-connected. Thus, biomass-derived electricity will have its major impact on the utility sector with respect to providing capacity for a variety of uses.

1.3 Resource Availability

The unavailability of low-cost fuel has been the principal limiting factor in the use of wood or other biomass in power generation. Nearly all current operations are fueled by waste or by-product materials. The cost of collecting biomass materials for power plant use ranges from $1.00 to $3.00/MilBtu, or as much or more than the total delivered cost of coal. Few biomass power plants have been built that rely solely on purchased materials; the economics are generally attractaive where waste or by-product material is available on a reliable basis at no cost (or possibly a credit if disposal is otherwise required).

As shown in Table I, biomass is an abundant resource. At present, less than three quads of biomass are used annually, indicating that

Table 1. Potential Energy Available from Biomass in Year 2000 (Quads)

Resource	Estimated Recoverable	Theoretical Maximum
Wood and Wood Wastes	10.4*	25.0
Municipal Solid Wastes		
Combustion	1.8*	2.0
Landfill Methane	0.2*	1.0
Herbaceous Biomass and Agricultural Residues	1.0*	15.0
Aquatic Biomass	0.8	7.7
Industrial Solid Wastes	0.2	2.1
Sewage Methane	0.1	0.2
Manure Methane	0.05	0.9
Miscellaneous Wastes	0.05	1.0
Total	**14.6**	**54.9**

*Appropriate for biomass electric generation

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significant resources will be available for electric generation. Currently, wood and wood wastes from conventional forests are the primary biomass resource. As the demand for energy grows, fast-growing trees and energy crops can provide additional feedstocks. The location of biomass resources are summarized in Figure 4. A more detailed description of the potential for growing more biomass is presented in more detail in the transportation (methanol) technology rationale.

In addition to woody biomass crops, municipal solid wastes are an important resource for electric generation. Annually, more than 200 million tons of refuse are generated in the United States. Although this represents an ever-increasing environmental problem, it can provide a unique opportunity for energy production.

In 1976 when the Resource Conservation and Recovery Act (RCRA) was enacted, an estimated 30,000 landfills were in operation. By 1984, the number of landfills had decreased to 9284, and the current estimate is 6034. Of these 6034 operating landfills, the U.S. Environmental Protection Agency (EPA) projects that 2000 will close within 5 years resulting in an annual loss of 56 million tons of capacity. The declining landfills will provide additional opportunities for municipal waste-fired electric generation.

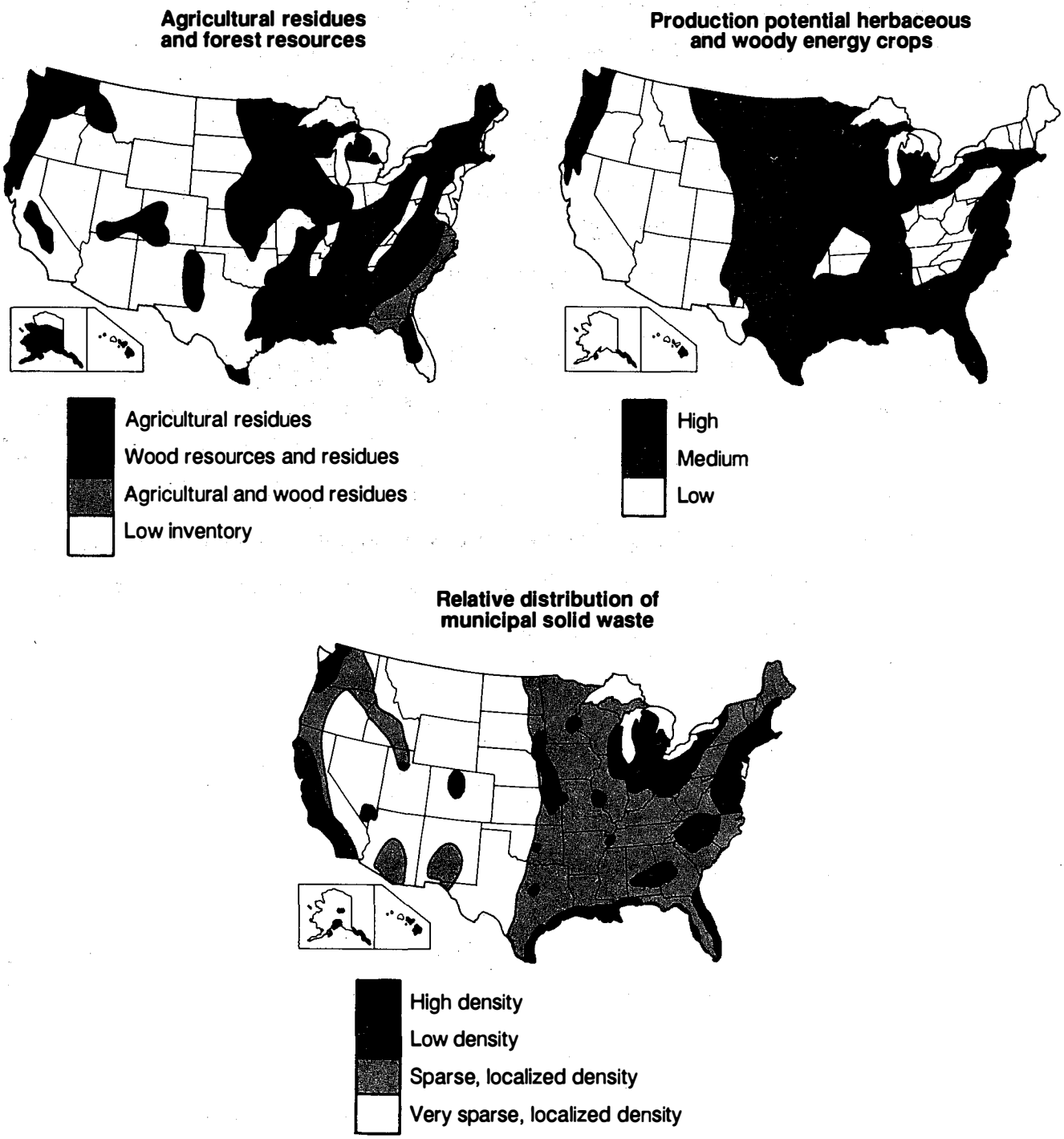

Figure 4. Location of Biomass Feedstocks

1.4 Market Acceptance and Experience

Conventional (steam) electric power generation is commercial technology today, and is accepted in cases where the cost of fuel is competitive with that of fossil fuels. The future commercial acceptance of biomass powered gas turbine systems should be excellent since industry and the utilities are already familiar with turbine generator systems powered by natural gas. In addition, the trend in power generation is away from large facilities that are increasingly perceived as being too risky financially, toward modular units that can be built quickly and for which standardized designs are feasible. Turbine systems at about 50 MW meet this need.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

The major growth market for electricity from biomass will be providing grid electricity. Therefore, production and costs of production are defined in terms of electricity produced. Key figures of merit which will impact on this technology ae listed below.

Key Figures of Merit:

- Cost of electricity ($/Kwh) - The cost of electricity summarizes the total cost of electric production, expressed as dollars per kilowatt hour of electricity generated. Included in this value are capital recovery, operating and maintenance costs, fuel costs, and feed costs. The capital recovery includes return on investment.

- Capacity (MW) - Plant capacity is defined in terms of the amount of electricity generated, and is expressed in terms of MW or KW.

- Capital Investment ($/Kw) - Plant capital cost is defined in terms of fixed capital investment per unit of electricity generated.

- Capital Recovery ($/Kwh) - The capital recovery component of the cost of electricity is defined in terms of dollars per kilowatt hour of electricity recovered. Dollars are calculated based on a yearly percent recovery of fixed capital investment and working capital. Electricity generation is on an annual basis.

- Operating and Maintenance Costs ($/kWh) - Operating and maintenance (O&M) costs are expressed as annual costs in dollars

divided by annual electricity generation.

- Feed Costs($/kWh) - Feed costs are expressed as annual feed cost divided by annual electricity generation. Alternatively, feed costs may be expressed as $/million Btu or $/ton. Feed cost in $/kWh includes process efficiency, while $/MilBtu and $/ton do not.

- Process Heat Input (Btu/kwh) - Process efficiency is expressed in terms of the heat input in Btu required per kilowatt hour of electricity generated. If the heating value of the feed is known then tons of feed per kilowatt hour can also be calculated. Process efficiency can also be expressed as a percent by converting Btu to kilowatt hours. For a steam turbine system, process heat input is equivalent to turbine efficiency. For an integrated system, e.g. gasifier-gas turbine, turbine efficiency must be calculated separately from process heat input, and is based on the heating value of gases exiting the gasifier.

2.2 Historical Technology Trends/ Current Status

Biomass/Steam Electric

Conventional (steam) electric power generation using biomass as a fuel is economic today in situations where the cost of the fuel is competitive with that of fossil fuels. The cost of a commercially available biomass steam-electric power plant is about $1,570/kW for a wood-fired facility[3]. If wood can be obtained at a cost of $2.00/MilBtu, the total cost of power for base-load operation will be about 6.1¢/kWh. If wood or agricultural wastes are available at lower costs, the cost of electricity will be significantly lower. Similarly, if the low-pressure steam from the turbine exhaust can be used (cogeneration), the overall efficiency will be higher and the costs will be lower.

The costs of a conventional, commercially available, wood-fired, steam-electric power plant are approximately as follows, using the SAIC evaluation.

Wood-Fired Plant

Utility-owned, base-load (or high-mid-range) service
50 MW capacity, 70% capacity factor
Heat Rate: 12,000 Btu/kWh

Capital Cost:	$1,570/kW
	2.8¢/kWh levelized (constant 1988 dollars)
O&M Cost:	0.9¢/kWh levelized (constant 1988 dollars)
Fuel Cost:	($2.00/MilBtu)
	2.4¢/kWh levelized (constant 1988 dollars)
Total Generation Cost:	6.1¢/kWh levelized (constant 1988 dollars)

Biomass/Gas Turbine Electric

Biomass powered gas turbines offer potential advantages for future electric generation. With gas turbines, the fuel is burned, and the hot combustion gases directly propel the turbine to provide shaft power. By eliminating the need to produce steam as an intermediate working fluid, higher efficiencies of operation can be obtained.

At present, gas turbines using clean liquid and gaseous fuels such as gas and oil are in operation for electricity generation. Solid fuels such as biomass are not presently

used since those fuels are more difficult to burn cleanly and completely. The combustion gases must be very low in particulates to avoid corrosion and erosion of the turbine blades.

Some attempts have been made to operate turbines on biomass. A 3 MW Allison 501-K turbine coupled with an external, sawdust-fired combustor has undergone trial operation in Red Boiling Springs, Tennessee. The primary emphasis of this work has been to determine the extent of hot gas clean-up required to ensure adequate turbine life. The system has operated successfully at temperatures less than 790°C, but encountered ash deposition in the turbine blades at higher temperatures. At this point, the technical feasibility of this approach is not yet demonstrated.

The problems which were encountered in this work can potentially be avoided by first gasifying the biomass feedstock to form a clean fuel gas. The fuel gas would be burned in a turbine, much like natural gas is used at present. Due to the lower gasifier temperatures and lower gas volumes in the gasifier, the fuel entering the turbine should be cleaner than the hot gases from the external combustor.

3.0 COST PERFORMANCE PROJECTIONS

Because biomass combustion/steam electric generation systems are mature technologies, only incremental improvements in production costs are expected. As a result, the capital costs of steam electric generation are expected to remain at about $1570/kWh. Overall thermal efficiencies in converting the energy of the wood into electricity will remain at about 25% for wood with 50% moisture, requiring about 12000 Btu/kWh. For systems where dry wood is available, higher efficiencies are possible, primarily due to increases in boiler efficiency with lower moisture content feeds. When dryers have to be added, the additional costs of capital and operation frequently offset the increased efficiencies. The largest uncertainty will be fuel costs. In many local situations, conventional wood and wood wastes can be obtained for $2.00 or less per million Btu. While these opportunities may be available in limited numbers in the future, conventional wood resources will not allow rapid growth of this technology. Thus, increase of biomass derived steam/electric systems will be dependent on development of low cost woody energy crops past the year 2000.

More recently, extensive interest has been expressed in the use of biomass powered gas turbines for electric generation.[4-6] These advanced systems would use hot combustion gases rather than steam as a working fluid. Biomass would first be converted to a gaseous fuel using a gasifier. The fuel gas would be burned, and the hot combustion gases would drive the turbine system. These systems offer the potential for higher efficiencies and lower electric generation costs than conventional systems. Alternatively, liquid fuels from biomass could be used to power the gas turbine. Efficiencies can be increased even more by recovering heat from the turbine exhaust, converting the heat to steam, and injecting steam into the turbine. These steam-injected gas turbine (STIG) systems have been the subject of substantial recent analysis. A typical conceptual biomass/gas turbine system is shown in Figure 5.

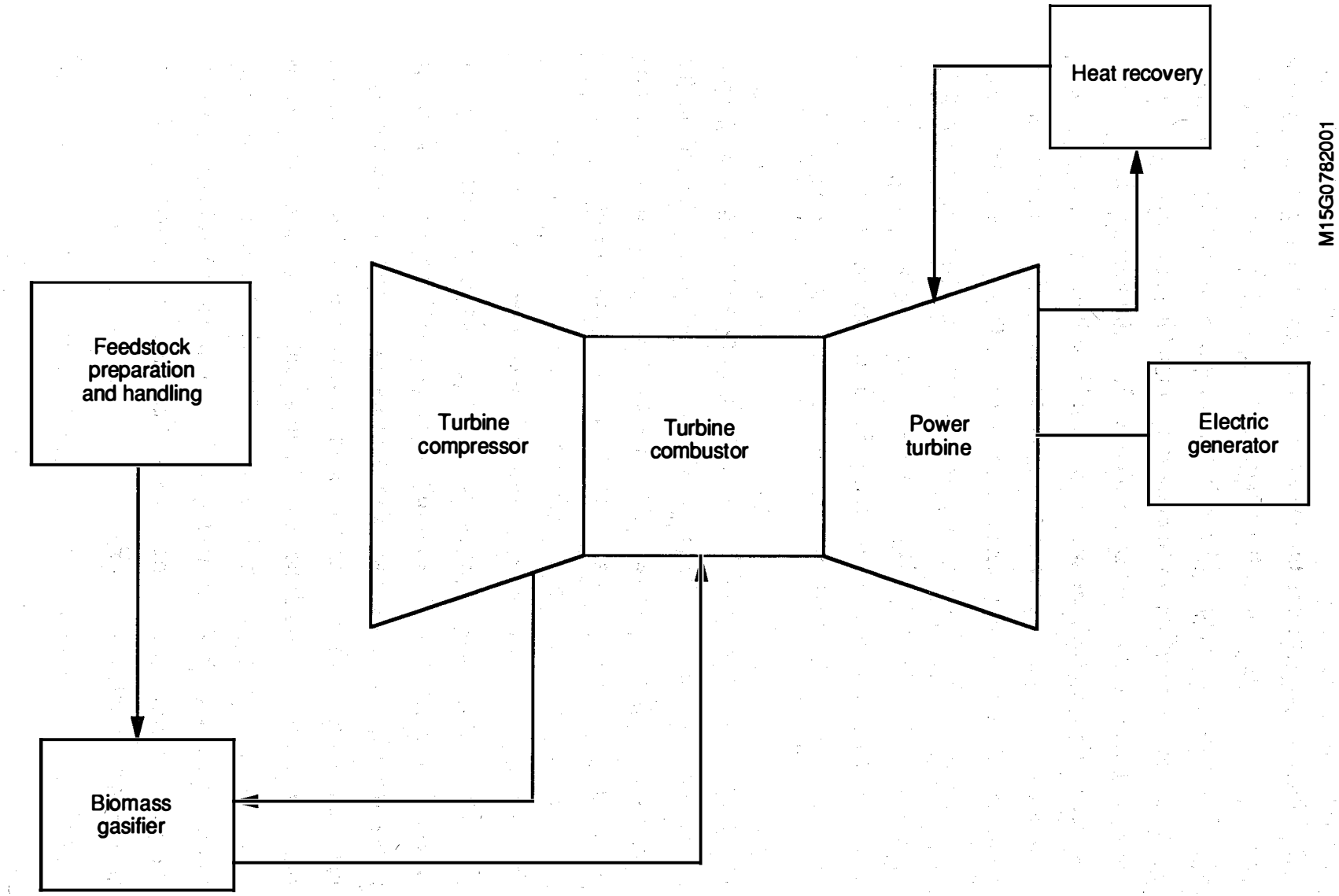

Figure 5. Biomass Gas Turbine System Conceptual Process Flowsheet

While biomass powered gas turbine systems are not presently in use, several recent analyses of this technology have been published. The analyses[4-6] indicate that electricity cost in the range of 4.5¢/kWh is possible. However, these biomass systems are not developed sufficiently to allow commercial implementation. Many different types of biomass gasifier and gas turbine configurations are possible. In most of the systems being proposed, the heat in the turbine exhaust gas is recovered as steam. The steam is subsequently re-injected into the turbine to increase gas volume and efficiency. These steam-injected gas turbines (STIG's) have high efficiencies[4] of approximately 33%. The Btu's required per kWh are reduced to less than 10,000. By comparison, coal-fired STIG turbines are only slightly more efficient at about 35%. In addition to the high efficiency, STIG turbine capital costs are projected to be low at about $1000/kWh of installed capacity, as shown in Figure 6.

In these analyses the costs of the various technology components are reasonably well known. The costs and performance of both the gasifier and the turbine have been shown independently in a variety of applications. The largest uncertainty is the technical feasibility of the system when these two components are combined. The gas from the gasifier must be of high quality to ensure long turbine life. While more research must be performed to resolve this issue, there do not appear to be major problems in reducing the particulates in the gasifier product stream to acceptable levels. The presence of volatile ash eutectics which could result in deposition of glassy material on the blades also appears to be controllable through various methods. As research confirms the technical feasibility of this approach, the goal of reaching 4.5¢/kWh should therefore be attainable. A comparison in conventional steam and gas turbine systems is shown in Table 2. A comparison of contributions to electricity price is shown in Figure 7. The increased efficiency of the turbine increases energy output and lowers feedstock costs, and the lower capital requirements further reduce costs.

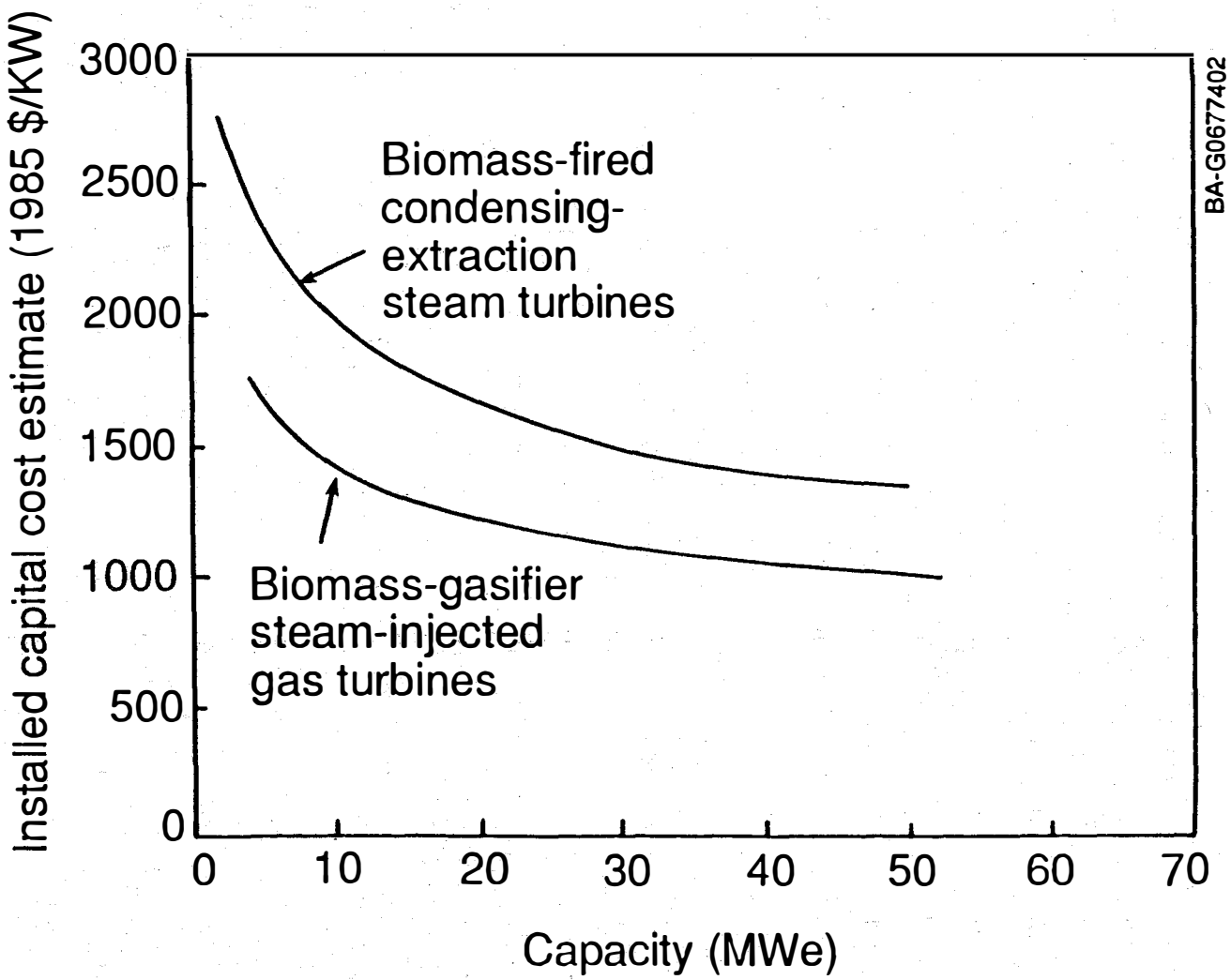

Figure 6. Estimated Unit Installed Capital Costs for Biomass-Fired Electric Generation Systems

Table 2. Comparison of 50 MW Biomass Electric Generation Technologies

	Conventional Biomass/Steam	Biomass/ Gas/Turbine
Efficiency (%)	25	33
Installed Capital Cost ($/kWh)	1570	1000
Electricity Cost (¢/kWh)	6.1	4.5

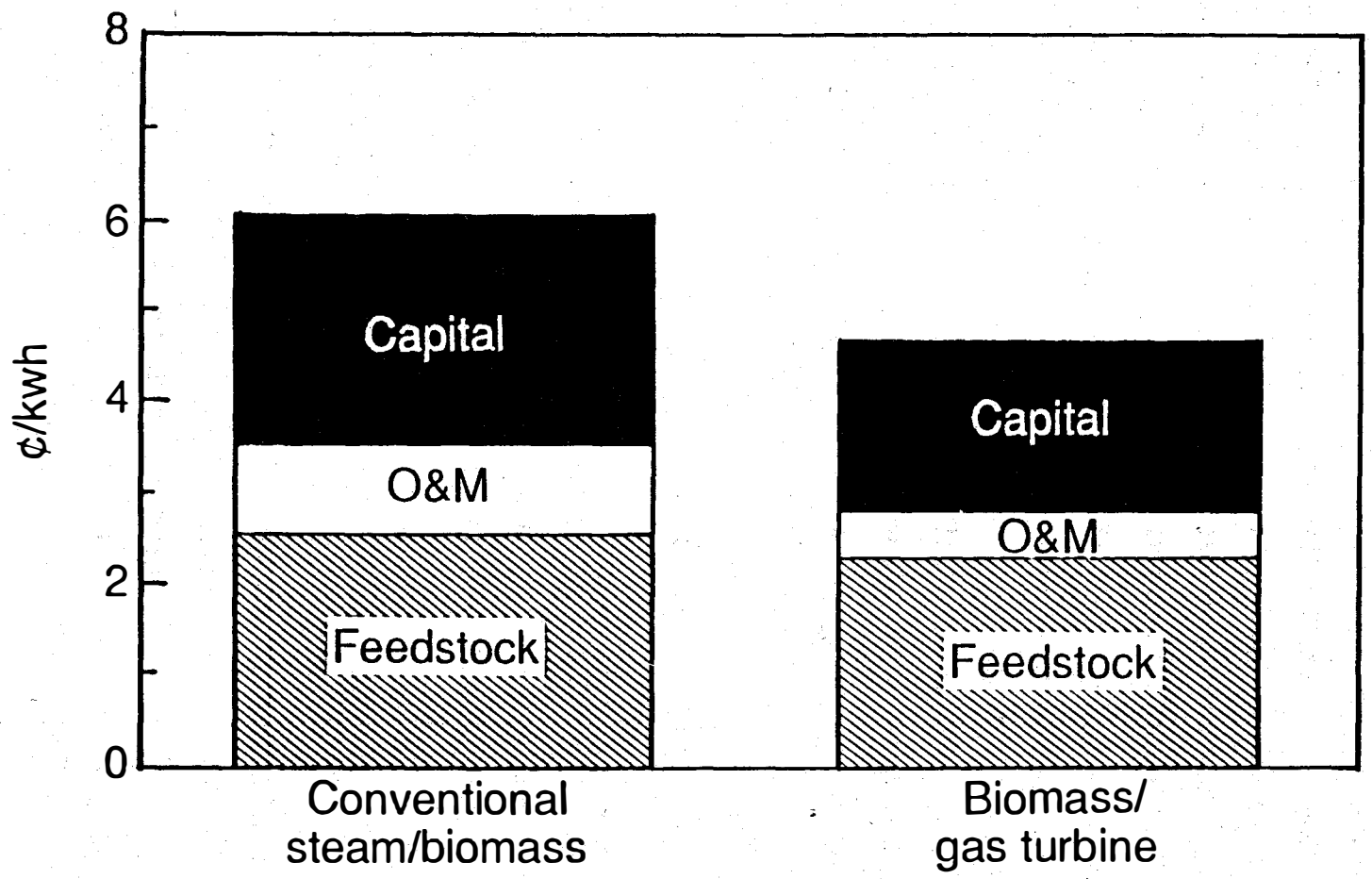

Figure 7. Comparison of Biomass Electric Technologies

3.1 Base Case Funding Scenario

Biomass/Steam Systems

Under base conditions, conventional biomass/steam electric generation is considered to be the primary technology for implementation over the next 10-15 years. Wood will be the primary feedstock for this technology. Wood and wood wastes from conventional sources will be used as long as supplies are available at costs of about $2.00/million Btu. As the costs of short-rotation woody crops are lowered, the use of wood for electric generation will spread to areas where supplies are not presently available. Under the base case, the R&D efforts will have significant impact on the deployment of the conventional steam-electric technology but will have little impact on cost. In both cases, the R&D will make the technology available in areas where it is not presently feasible. However, the biomass/steam electric generating systems are mature technologies, and the costs of generating electricity will remain approximately level at 6.1¢/kWh, as shown in Figure 8.

Biomass/Gas Turbine Systems

Implementation of biomass/gas turbine technologies will require research and development efforts to ensure that the fuel characteristics are compatible with the turbine. At present, this technology presents too great a risk to be considered commercial. A focused research program is needed to resolve remaining technical uses and to demonstrate the feasibility of this technology. To accomplish the research and development of the biomass/gas turbine technology, funding of approximately $50 million over a period of about six years is required. Under the base case, however, the development of this technology is considered to be entirely the role of industry. The base case leaves a very uncertain future for the advanced gas turbine technology. Advances in coal/turbine systems and advances in turbine technology may slowly lead to commercial implementation of biomass/gas turbine

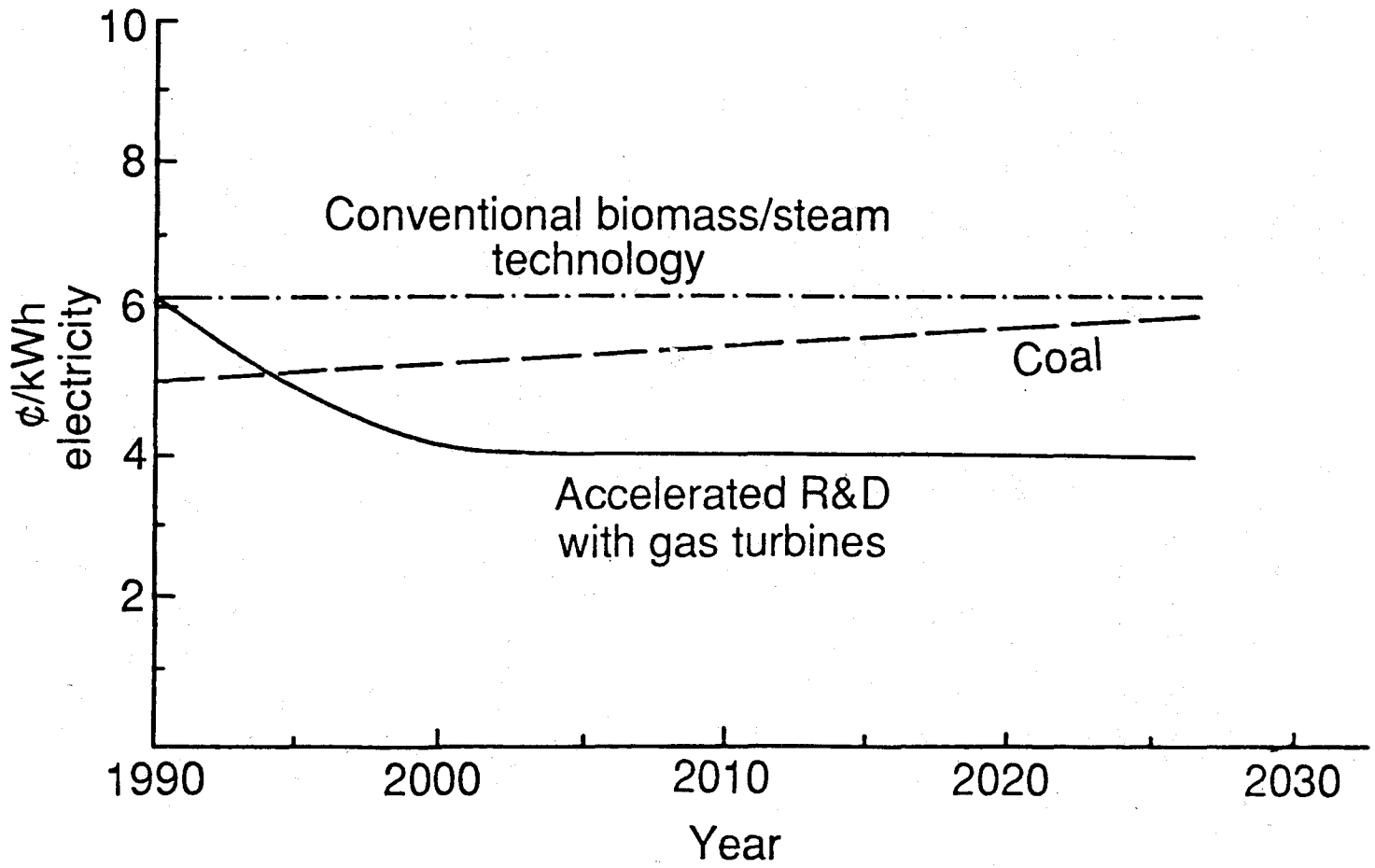

Figure 8.

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systems. Environmental issues may also push the development of this technology. However, the rate of development will be slow and the technology will not be available until approximately 2010. Reduced feedstock costs will contribute to the attractiveness of this technology, but progress toward electricity at 4.5¢/kWh will be slow.

3.2 Accelerated R & D Funding Scenario

Under accelerated R &D, a federal program would lead to much more rapid progress. The research program can be completed in about seven years, making significant impact possible in less than 10 years. With the accelerated R&D case, much of the new biomass electric capacity added past 2000 would be gas turbine rather than steam turbine based. To complete the biomass turbine development program, research in the following areas is needed:

- Gasification and particulate removal from the hot gas stream
- Demonstration of gasifier/turbine systems at a reasonable scale
- Systems analysis
- Use of biocrude liquids as turbine fuels

These elements are discussed in greater detail in Section 4.0.

4.0 RATIONALE FOR TECHNOLOGY IMPROVEMENTS

This discussion focuses biomass powered gas-turbine systems. Feedstock cost reductions are discussed in the biomass-to-methanol section. Conventional biomass-steam systems are not discussed here because of their maturity. Areas of expected improvement for biomass-powered gas-turbine systems include:

Particulate Removal from the Hot Gas Stream

As indicated previously, particulates or vaporized alkali metals can potentially lead to major problems in gas turbine systems. Research is needed to ensure that the hot gases entering the power sections of the turbine meet the stringent quality requirements for this application.

Research and Development Approach

Laboratory research is required to identify the source of turbine blade deposits which were noted in previous biomass combustion/turbine studies to determine whether these problems arose from vaporized alkali metals or from particulates which softened and subsequently deposited on the blades. Research should include testing with laboratory gasifiers and turbine test rigs as well as analytical studies to determine the source of these deposits. The research should also identify methods to remove particulates through temperature control, the use of additives in the feeds, and the use of mechanical systems for removing particulates.

Concepts which offer promise at the lab scale should be tested at one or more of the existing experimental gasifiers (approx. 10 tons/day scale). Initial particulate removal tests need to be conducted to ensure the gasifer product meets turbine requirements. Additional laboratory tests with a closely coupled gas turbine (approx. 300 kW) would verify these results prior to the full scale gasifier (100 ton/day) and turbine (5

MWe) system verification tests.

Progress Expected

By 1995, successful completion of this research program will ensure that the fuel gases from biomass gasifiers meet turbine inlet spectifications. Typically, these spectifications require that total particulate loadings of 100 grains per cubic meter be attained with over 90% being less than 0.5 microns in size. Present cyclones and other filtering devices can meet these rquirements, but it is essential to adapt them specifically to the integrated biomass gasifier system. For instance, the pressure drop in the filtration system must be kept to a minimum to avoid losses in system efficiency. In addition, the subject of ash vaporization must be addressed. The vapors of low-temperature eulectic salts can potentially pass through conventional filtration systems. Research will determine if salts are vaporizing in the system and will define methods to prevent this phenomenon. The ability to clean the hot fuel gas is essential to this technology. The product must meet commercial turbine specifications or the technology will not be implemented.

Systems Analysis

There are many possible combinations of the different types of gasifiers, pyrolyzers, turbines, and exhaust energy recovery systems. Although some of the more obvious combinations are addressed here, an in depth study by carefully selected industrial and academic consultants could help to ensure that the research efforts are properly directed.

Research and Developmental Needs

Technoeconomic studies need to be made to determine how to specifically take advantage of the unique aspects of utilizing fuels generated by gasification and/or

pyrolysis of biomass. This study should be of a continuing nature, starting with the most obviously advantageous systems (e.g., co-generation applications).

The progress and direction of the program needs to be periodically reviewed by industry for its usefulness to industry. This review board would consist of representatives of the turbine industry, utilities companies, and the fledgling biomass conversion industry. The recommendations of this review board would be used to guide the direction of the program.

Progress Expected

By the year 1996, research wil have identified the lowest cost systems for integrated biomass gasifier technologies. Present analyses are based on generic equipment and have a high degree of uncertainty. The analysis will reduce cost uncertainties to ±15% and will identify specific equipment combinations which can be used in systems producing electricity at about 4.5¢/kWh. Ongoing analysis is required through the demonstration phase to ensure the most economic technologies will be available.

Gasifier Demonstration

Gasifiers are divided into two major classes for purposes of this discussion; 1) air-blown low Btu gasifiers and; 2) oxygen-blown or indirectly heated medium Btu gasifiers. This division is based primarily upon the method of supplying heat to the gasifier. Because of the higher reactivity of biomass and biomass char under gasification conditions, biomass gasifiers are typically operated at lower temperatures than coal gasifiers. Operation at lower temperature reduces heating requirements.

In low Btu gasification, air is used to supply the required gasification process energy through combustion of a portion of the biomass. Low-Btu gasifiers are attractive for

turbine use if major modifications are successfully made to the turbine system. The low heating value of the product gas requires that the gasifier be closely coupled with its end use application. This will require extensive modification of the turbine combustor and associated systems. As a result, a turbine development effort may be required to successfully operate with a low Btu, air-blown gasifier.

With medium-Btu gasifiers, the heat for reaction is provided either by partial combustion with purified oxygen or by providing the heat through an indirect heat exchange process. The use of oxygen gasifiers operated at typical gas turbine inlet pressures, 75 to 300 psia, may improve overall process efficiency by reducing gas compression costs. When used in a combined cycle electrical generation system, nearly 50% of the energy in the hot gas stream can be converted to electricity. Indirect gasifiers use the heating value of co-produced char to provide heat for gasification. Typically, these gasifiers have operated at low pressure, but some types may be suitable for pressurized operation. With either type of medium-Btu gasifier, the heating value of the gas reduces the stringent requirement for close coupling the gasifier with the turbine. Although the medium-Btu product costs about $1.00/Mbtu more than the low-energy product, the turbine system will require little or no modification. The medium-Btu option therefore may offer the best opportunity in the near-term.

In either gasification-gas turbine system to produce electricity, biomass gasification is used to produce fuel gas which is fed to the combustion section of a gas turbine. The residual tars should be consumed during the combustion process, but ash contained in entrained char may cause turbine blade pitting and corrosion. If tars are not completely combusted then some type of catalytic hot gas cleanup may be required.

Research and Development Approach

A gasifier/turbine combination of reasonable scale (approx. 5MW) is needed to demonstrate the feasibility of this concept. A 100 ton/day medium Btu gasifier will operate a 5 MWe turbine. Demonstration at this scale will utilize funds appropriated for a DOE gasifier scale-up facility. The facility will serve as a verification case for this technology and will resolve final technical issues at large scale. The issues of hot gas clean up and gasifier operability will be examined. Methods to ensure rapid start-up of the turbine will be tested. In addition, the ability of the gasifier to sustain a constant load on the turbine without major fluctuation will be determined.

Research on wood drying and storage for the system is also needed. Unfortunately, most of the drying methods developed by the forest products industries utilize driers which are heated directly by combustion; this can utilize as much as 20% of the net energy in the biomass. Many of the commercial dryers cannot dry much below 10% moisture content without risking accidental fires in the dryer. There is a need to develop rapid and inexpensive methods to dry biomass fuels using the relatively low temperature heat normally available as waste heat in a power plant or in industrial processes, e.g. using technology developed for the drying of grain in silos, but which has not been applied to wood chip drying. Economical approaches to the storage of dried wood fuels are also needed, e.g. low cost air supported enclosures or plastic tarps. Wood drying and storage improvements should be included in the gasifier scale-up facility

Expected Improvements

By the end of FY 1997, the demonstration of this technology will be complete. The feasibility of the technology will have been shown at the 10 ton/day scale using biomass gasifiers and turbine test rig simulators. The DOE gasifier scale-up facility will be complete (100 tons/day) and a 5 MW gas turbine will have been tested. At this point, the technology will be ready for commercial implementation.

Biomass Liquefaction for Electrical Generation in Combined Cycle Systems

One method used by the utilities to incrementally increase their capacity is to add an oil-fired gas turbine/generation and provide the exhaust heat to an existing steam driven electric plant. Overall energy efficiency of oil to electricity for a combined cycle system of this type approaches 50%. Alternatively, the oil fired turbine/generation could be used on an intermittent basis to provide peak-load electricity to command a premium value, although often at lower overall efficiencies, since in this mode heat is not necessarily recovered in a steam boiler.

Liquid fuels from biomass can therefore be potential fuel source for electric generation using gas turbines without the modifications required for biomass gasifiers.

DOE sponsored research has shown that it is feasible to pyrolyze biomass to produce pyrolysis oil yields of about 60 wt% (dry basis) at atmospheric pressures and at very low cost. This low viscosity oil is noncarcinogenic, highly oxygenated for clean combustion, has low sulfur and ash contents, and good storage properties in the laboratory. The volumetric heating value of this storable oil (as produced with about 20% moisture) is about 50%, 110%, and 450% of that of petroleum, methanol, and wood chips, respectively. DOE studies have shown that even biomass derived oils having much higher viscosities can be very successfully burned in the combustor of an oil-fired gas turbine. The production of this pyrolysis oil can be coupled to a very efficient combined cycle generation of electricity through the use of a combustion turbine exhausting to a boiler to raise steam for use in a steam turbine. The production of the pyrolysis oils has been proven at a scale of 50 lb wood/hr, although using slightly different conditions than would be used in a commercial plant.

The generation of the pyrolysis oils could take place in satellite pyrolysis plants for shipment to a large central power plant for efficient base load generation or for

storage to use in meeting seasonal peak electrical loads.

Research and Development Approach

The existing DOE bench scale pyrolysis system needs modification to verify that the flow sheet to produce oils having a low moisture content is feasible with recycled pyrolysis gas. A larger system is also needed to produce enough pyrolysis oils for long term turbine tests by a turbine manufacturer. This would allow the technologies for the production of electricity to be commercialized in the 1990's time frame. Industrial interest in this process exists, but there has been a reluctance to proceed prior to the generation of scale up data for pyrolysis, in spite of enthusiastic efforts of small business to promote this process. There is potential for significant cost sharing with small business and DOE to reduce the risk of investment for this process.

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Section 3

TECHNOLOGY EVOLUTION RATIONALE FOR GEOTHERMAL TECHNOLOGY

October 5, 1990

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Preface

This document contains the rationale for projections of cost, performance, and market penetration by geothermal electric technology in various cases of the National Energy Strategy (NES). The rationale supplements the earlier document, Renewable Energy Technology Characterizations, September 10, 1990, and other submissions by the Geothermal Division, DOE, in conjunction with NES analysis activities.

Section 1 reviews the nature and extent of geothermal resources, basic components of geothermal energy systems, achievements to date, status of the industry, and market conditions for geothermal development. Section 2 addresses figures of merit for evaluating the economic viability of geothermal electric projects; technology trends affecting cost are also given. Section 3 examines three scenarios of projected change in cost and performance, based on the judgment of DOE and independent experts: a base case in which recent trends in industry and technology improvement continue in a business-as-usual manner; an accelerated R&D case in which the pace and scope of technology improvements by the Federal program are increased; and an augmented case in which hot dry rock technology is developed as a logical follow-on to hydrothermal technology. Finally, Section 4 presents the rationale for achieving the improvements in the near to long terms.

1.0 INTRODUCTION

1.1 Technology Description

Geothermal energy -- the heat of the earth -- originates from the earth's molten interior and the decay of radioactive materials in the crust. In some places, this heat comes to the surface in natural streams of hot water or steam, which have been used since prehistoric times for cooking and bathing. Today, man-made wells convey the heat from subsurface reservoirs to homes, farms, factories, and electric generators.

As shown in Figure 1, there are four types of geothermal energy -- hydrothermal, geopressured, hot dry rock, and magma -- with different physical characteristics. The differences necessitate variations in extraction technologies. All forms of the resource are potentially capable of electric power generation if sufficient heat can be obtained for economic operation. However, the power conversion technologies employed vary according to the form and temperature range of the resource. The heat of the resources having less potential for this purpose -- those with temperatures below approximately 150°C (300°F) -- can be used directly for space heating and cooling, geothermal heat pumps, crop drying, commercial greenhouses, fish hatcheries, thermal enhanced oil recovery, and industrial processes.

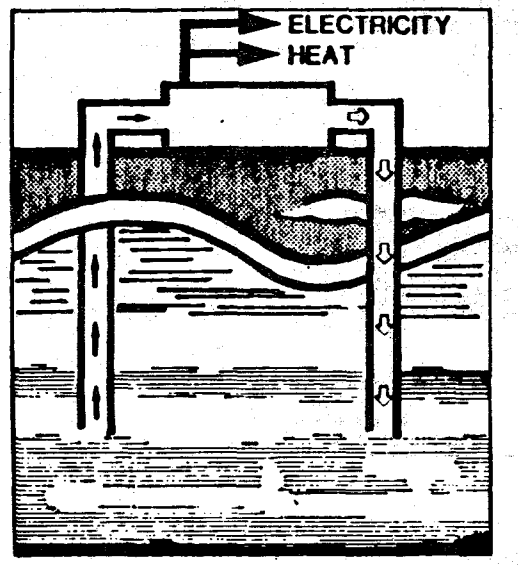
To date, all commercial development of geothermal energy in the United States -- both for power generation and direct use -- employs the hydrothermal resource. For this reason, the discussion herein largely focuses on hydrothermal technology. The advanced technology needed for economically extracting the heat or other forms of energy from geopressured brines and hot dry rock is currently under development by the Geothermal Division. Due to higher priorities, DOE has proposed to defer further research on magma, beginning in FY 1991.

Figure 2 presents the main components of a hydrothermal electric system. The geoscientific, drilling, and conversion technologies that drive these systems are described below.

Energy Extraction

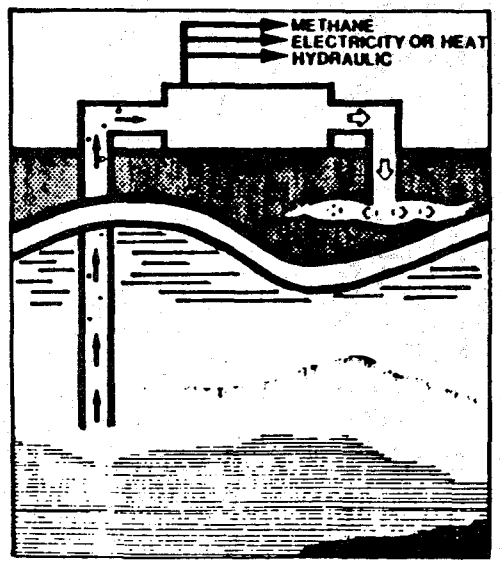
The geosciences -- geology, geophysics, and geochemistry -- are used to locate reservoirs, characterize subsurface conditions and optimize placement of exploratory wells and production/injection wells. In hydrothermal applications, conceptual geological models define the geometry and physical properties of the reservoir; geochemical models analyze changes in reservoir fluids and rocks; and numerical simulation models predict long-term reservoir behavior.

Drilling technology used for geothermal development historically derives from the petroleum industry. Certain critical components, such as drilling muds, were modified to work in high-temperature environments. These measures proved only marginally



HYDROTHERMAL

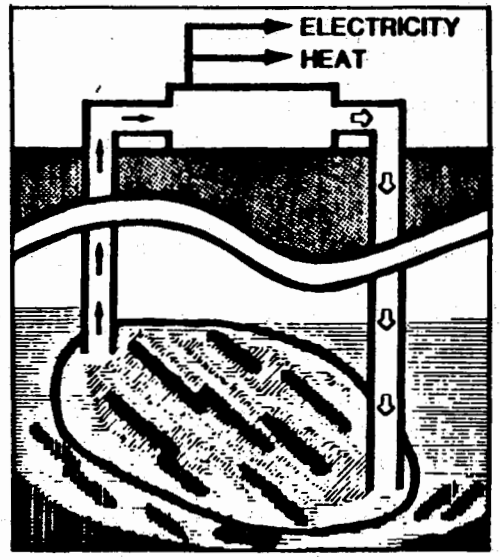
Water and/or steam trapped in fractured or porous rocks; classified as either liquid-dominated (hot water) or vapor-dominated (steam) according to the principal physical state of the fluid.



GEOPRESSURED

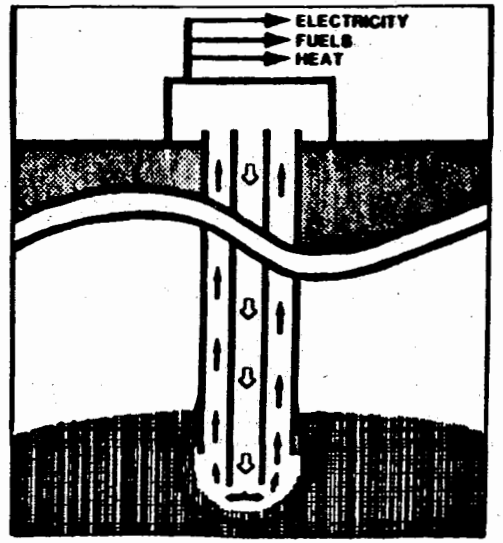
Brines at moderately high temperatures (300-400°F) under higher than hydrostatic pressures containing dissolved methane.

Figure 1. The Four Types of Geothermal Resources



HOT DRY ROCK

Relatively water free, but unusually hot, impermeable rocks at accessible depths. To extract heat, the rock must be fractured, and a man-made, confined fluid circulation system created.



MAGMA

Molten or partially molten rock (>1400°F) at accessible depths in the earth's crust.

Figure 1 continued.

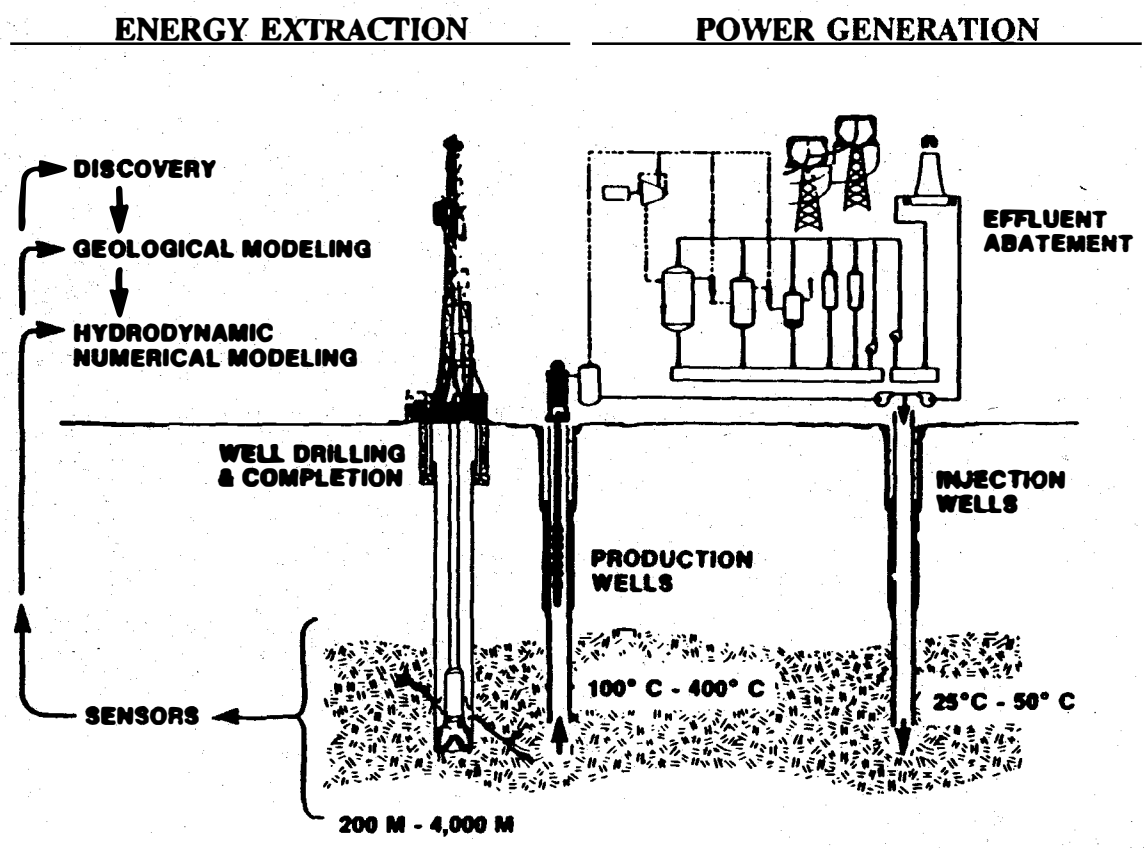


Figure 2. Major Sub-Systems of a Hydrothermal Electric Project

adequate, as materials and equipment have had to be designed to withstand not only increasing temperatures but hard, fractured rock formations and saline, chemically reactive hydrothermal fluids, typically referred to as "brines". As a result, a segment of the drilling industry devoted to geothermal development has evolved. Subsequently, improvements in drill bits, elastomers, and other drilling components for geothermal applications have been adopted as industry-wide standards. However, typical drilling costs for geothermal wells remain 2-4 times the petroleum industry average.

Hydrothermal fluids may be produced from wells by artesian flow (i.e., fluid forced to the surface by ambient pressure differences) or by pumping. In the former case, the fluid may "flash" into two phases, steam and liquid; whereas under pumping, the fluid remains in the liquid phase. The choice between production modes depends on the characteristics of the fluid and the design of the energy conversion system.

Power Generation

The energy contained in all four types of geothermal resources may potentially be used to generate electricity or to provide heat for some direct use of the fluid. Three different energy conversion technologies may be used for generating electricity with hydrothermal resources. The resource traits that influence the choice of a particular technology are the phase in which it occurs (vapor or liquid), its temperature, its pressure, and its chemistry. The three conversion technologies are:

- Dry Steam - Conventional turbine-generators are employed with naturally-occurring dry steam. There is no significant difference between this type of operation and conventional power generation with a medium-pressure steam turbine except that the natural steam typically must be filtered and chemically treated to remove particulates and trace constituents such as hydrogen sulfide. This technology is limited because dry-steam hydrothermal resources are rare. The nation's only commercial steam field is located at The Geysers in northern California.

- Flash Steam - When the temperature of liquid hydrothermal resources is 175°C (350°F) or above, flash-steam technology may be employed; see Figure 3. With this technology, some liquid flashes to steam as its pressure drops during production. The steam is separated from the liquid fraction and used to drive a turbine-generator. Since corrosive noncondensible gases may be liberated in the flashing process and high levels of dissolved solids may be present in the residual liquid, the materials used and the design of the system become critical in eliminating scaling and corrosion problems which could adversely impact economic operation. Today, the economics of most hydrothermal flash plants are improved by using a dual-flash cycle which separates steam at two different pressures. This method produces as much as 20-30% more power than a single-flash system at the same fluid flow rate. The application of flash-

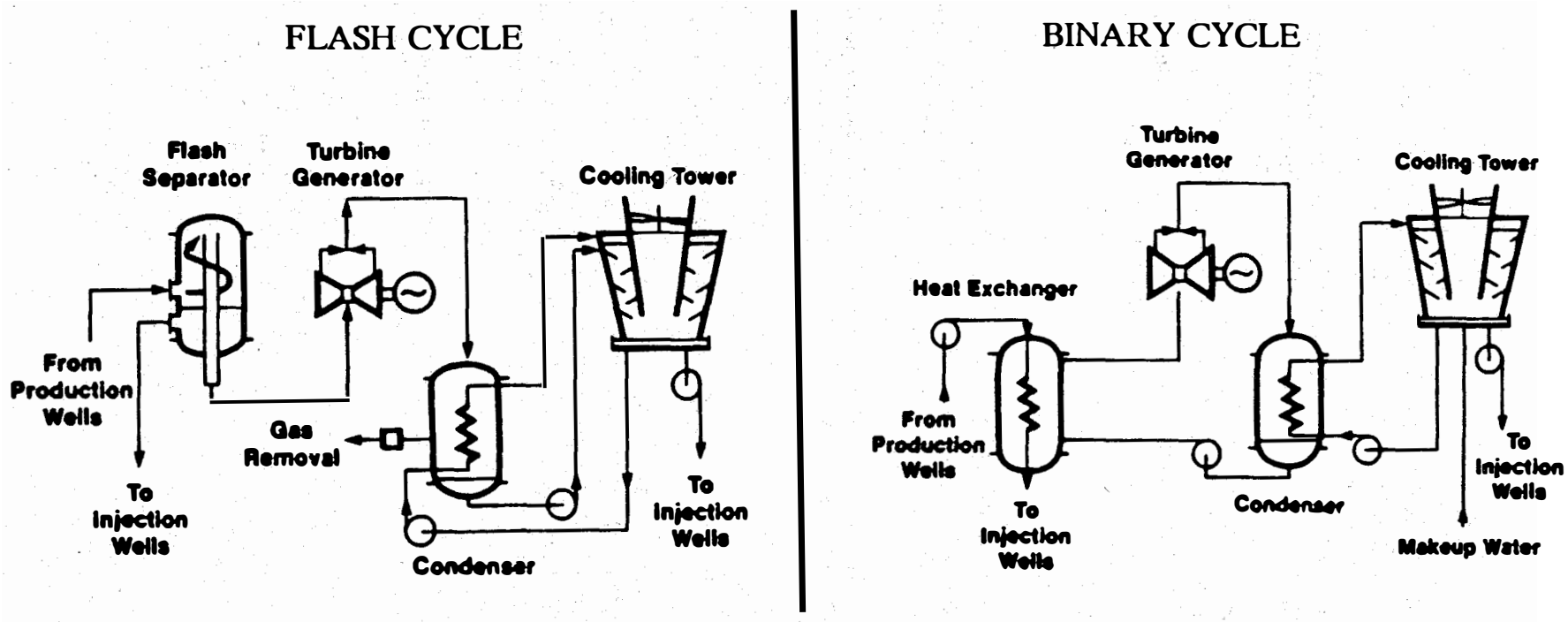


Figure 3. Hydrothermal Liquid Dominated Technology Options

steam technology is largely limited to high-temperature, liquid-dominated (hot water) reservoirs.

- Binary Cycle - Hydrothermal liquids with temperatures in the 100-175°C (212-350°F) range are more suited to binary cycle units to generate electricity. In this technology (Figure 3), the heat of the liquid vaporizes a secondary working fluid (e.g., isobutane) for use in the turbine. A number of binary plants are in operation ranging in size from units of less than 1 MWe to 50 MWe. Some larger plants are made up of multiples of small units -- e.g., the 30 MWe binary plant at East Mesa, California, has 26 1.2 MWe modules.

1.2 Technology Applications/Users

To date, U.S. hydrothermal electric plants have been used almost exclusively to provide baseload power to electric utility grids. The baseload characteristic is more or less intrinsic to the technology, since:

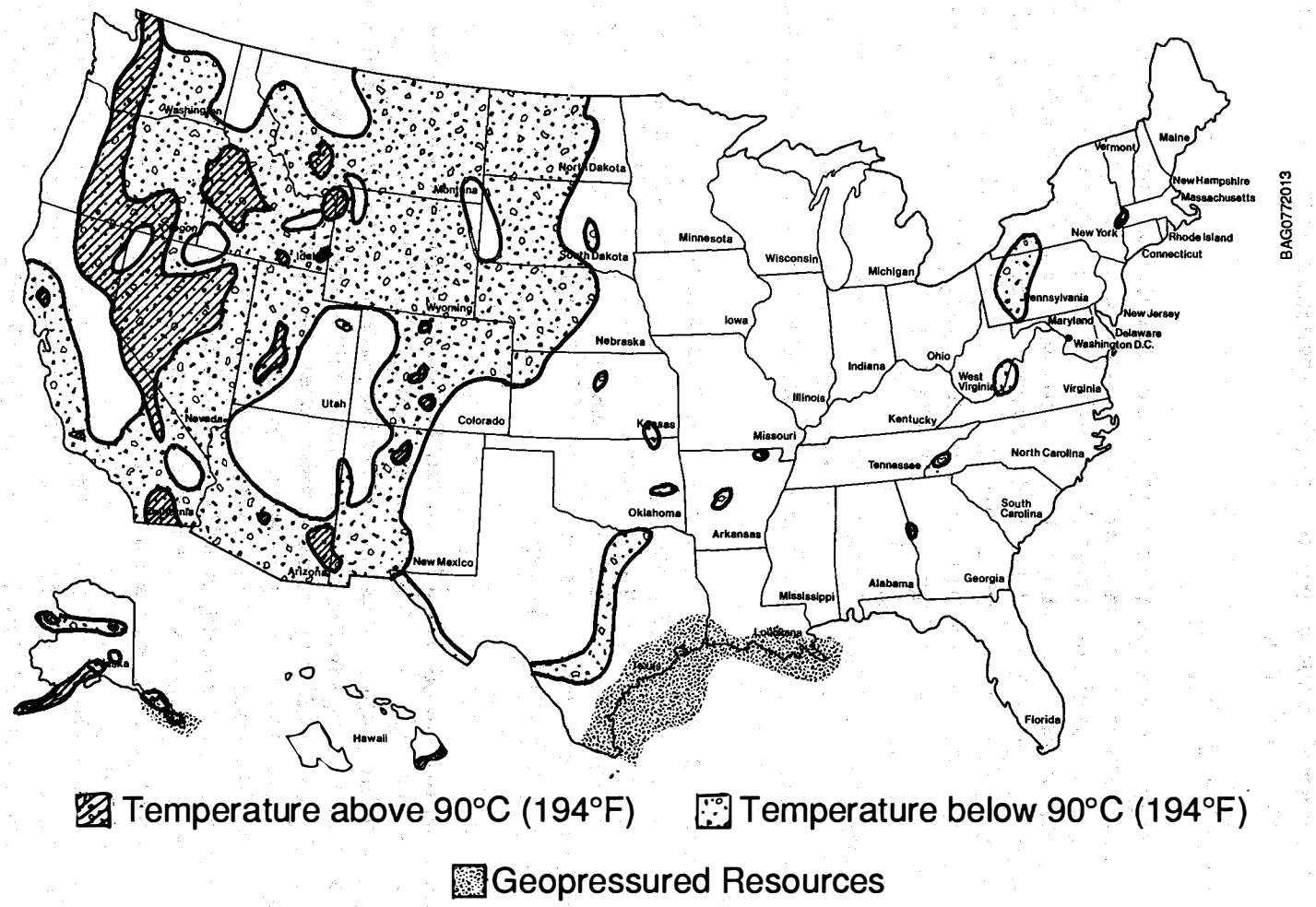
- The capital costs of the systems are relatively high and the variable operating cost is essentially a fixed percentage of gross revenue, leaving the economics best if the plant runs at full capacity; and

- Cycling of production/injection wells on and off rapidly can damage the wells or rock formations near the well-bore.

However, some interest has arisen in cycling dry-steam plants at The Geysers, the oldest and largest hydrothermal electric installation in the United States. The purpose is to increase the economic value of the remaining steam in that reservoir by matching its use to the peaking and intermediate-load portions of the utility's demand curves. Experiments to that end are in progress at The Geysers and at a similar dry-steam field at Lardarello, Italy.

In the late 1970's, the ownership/management pattern for most hydrothermal electricity systems followed the scheme originally used at The Geysers. There, a public utility owned and operated the power plants while the steam field was developed by private companies who sold steam to the utility. This pattern has changed markedly since about 1986. Most recent hydrothermal projects (field and plant) are owned and operated by a single entity, usually an independent power producer (IPP), rather than a utility. In this case, the utility buys electricity, rather than steam, from the producer. Currently, IPPs account for more than one-fourth of total installed geothermal capacity.

Utilities in three states, California, Nevada, and Utah, comprise major users of today's hydrothermal technology. Other users include geothermal developers, service companies, firms with multiple business interests (primarily petroleum and mining), equipment manufacturers, and entrepreneurs. Firms based in the U.S. dominate the



Temperature above 90°C (194°F)

Temperature below 90°C (194°F)

Geopressured Resources

Figure 4. Location of U.S. Geothermal Resources

domestic hydrothermal industry, except for turbine-generator systems which are largely dominated by Japan and Israel.

1.3 Resource/Land Use

Hydrothermal resources are found throughout the United States and its Trust Territories. Low temperature resources (in the range of 15° to 60°C; 60° to 140°F), which can be used in geothermal heat pump technology, are found virtually everywhere. The higher grades of resources are, however, distributed unevenly across the country. U.S. Geological Survey (USGS) Circular 892 describes the distribution of moderate-temperature hydrothermal resources from 60° to 90°C (140° to 195°F). The resources in this temperature range are widespread in the western and central regions of the U.S. but are limited to localized hot springs in the eastern part of the country. The distribution of intermediate (90° to 150°C; 195° to 300°F) and high-temperature (above 150°C; 300°F) resources is described in USGS Circular 790. All of these higher-grade resources depend on relatively recent tectonic activity for their creation. Tectonic activity in the western United States, Alaska, and Hawaii created the hydrothermal resources whose distribution is shown in Figure 4.

There still remains a fairly large degree of uncertainty as to the general amount of hydrothermal energy in the U.S., especially with respect to the economically-recoverable amount, or reserves. Recent resource estimates prepared for DOE (Figure 5) report 240 quads of reserves and an accessible resource base greater than 6200 quads [1]. USGS Circular 790 estimates a resource base of 2400 quads with a generation potential of 95,000 to 150,000 MWe for 30 years.

The estimates of hydrothermal resource base depend on geologic evidence, but the determination of the energy available at any one site requires detailed evaluation, particularly through drilling. The widespread geothermal heat pump resource has been confirmed by shallow water wells throughout the country. This energy source is 30% more efficient than conventional air-source heat pumps and air conditioners, and the general use of geothermal heat pumps could offset the need for 20,000 to 75,000 MW of new electrical generating capacity between now and 2030. The use of moderate-temperature hydrothermal resources could offset the need for over 1 quad/year of fossil fuels and electricity in providing process heat for industry and agriculture. The exact locations of the high-grade resources are more difficult and costly to confirm, and definition of resource sites requires drilling and testing of large wells.

The environmental impacts from hydrothermal energy are generally low; air emissions are very small compared to any fossil fuel. The typical geothermal electrical plant requires at most 5 acres of land per megawatt; the amount can be reduced substantially with space-saving designs, such as multi-well service pads, now in common use. Other hydrothermal applications are usually compatible with a variety of land uses. Geothermal heat pumps have been installed in congested urban areas, in suburban housing tracts, and in open agricultural developments. By 2030, most of the heating and

(In Quadrillion BTUs)

	TOTAL RESOURCE BASE	ACCESSIBLE RESOURCE	RESERVE
Temperature > 80°C	12,196	6,054	210
Temperature 40 - 80°C	7,492	202	30
Total	19,688	6,256	240

Source: U.S. Department of energy, "Characterization of U.S. Energy Resources and Reserves," June 1989.

Definitions:

1 Quadrillion BTUs = 0.170 BBOE (at 100% conversion efficiency)

Total Resource Base = the total physically available energy that encompasses both identified and undiscovered resources.

Accesible Resource = the resource that can be located, mined or extracted by technology currently available, or that will be available in the very near future (3 to 5 years).

Reserve = the subset of the accessible resource base that is identified and that can be economically and legally extracted with existing technology and under present economic conditions to yield useful energy.

Figure 5. Hydrothermal Resources and Reserves

air conditioning installations in homes and industry will need replacement, and geothermal heat pumps provide utilities with a cost effective alternative to offset the demand for new generating capacity with no new requirement for land.

1.4 Industry Status

The growth of domestic hydrothermal electric capacity is shown in Figure 6. Until the 1980's, that capacity came almost entirely from the large dry-steam field at The Geysers, where large-scale generation began in 1960. The Geysers remains the flagship of the industry, comprising two-thirds of today's domestic capacity. Technology improvements aimed at handling hot, saline brines became practicable in the mid 1980's, making certain high-quality, liquid-dominated (hot water) resources economic. Recent growth in hydrothermal capacity has been focused on these resources, while The Geysers apparently has reached its productive limit. Of the 806 MWe installed capacity derived from hot water resources, flash steam technology accounts for 622 MWe. The remainder, 184 MWe, is produced using binary cycle technology [2].

The Public Utilities Regulatory Policy Act (PURPA) had a positive effect on hydrothermal electric development in the 1980's. That effect is illustrated in Figure 7. Of the 2000 MWe of new capacity added during the 1980's, plants totalling over 700 MWe took advantage of either Standard Offer No. 4 (SO4) contracts in California or favorable terms promulgated by the Public Utilities Commission of Nevada. The effect is even more dramatic if development at The Geysers is excluded. With the withdrawal of SO4 offerings and reinterpretations of PURPA by the states, the immediate future of hydrothermal development is uncertain. Absent improvement in regulatory conditions and/or increases in electricity demand, new hydrothermal generating capacity added by the end of 1994 will probably only total 350 to 500 MWe [2].

At present, over 30 companies are actively pursuing hydrothermal field development in the U.S. For the most part these are small- to mid-sized firms, many with interests in other energy technologies. Of the large oil companies that held geothermal assets ten years ago all but one have withdrawn from the business. However, at least ten firms that pursued geothermal business in the late 1970's and early 1980's are still active today.

The supporting industry for geothermal development includes drilling companies, geoscientific firms, equipment suppliers, A&E firms, consultants, and many others. As of 1987, 156 different companies supplied goods and services for geothermal development [3]. Many of these companies rely on the petroleum industry for the bulk of their business.

In general, individual companies within the industry are reluctant to mount a major R&D effort. Nevertheless, some independent R&D has been performed on specific problem areas such as plant design, hypersaline brine handling, solid waste disposal, and casing materials. These efforts are limited monetarily and usually aimed at solving

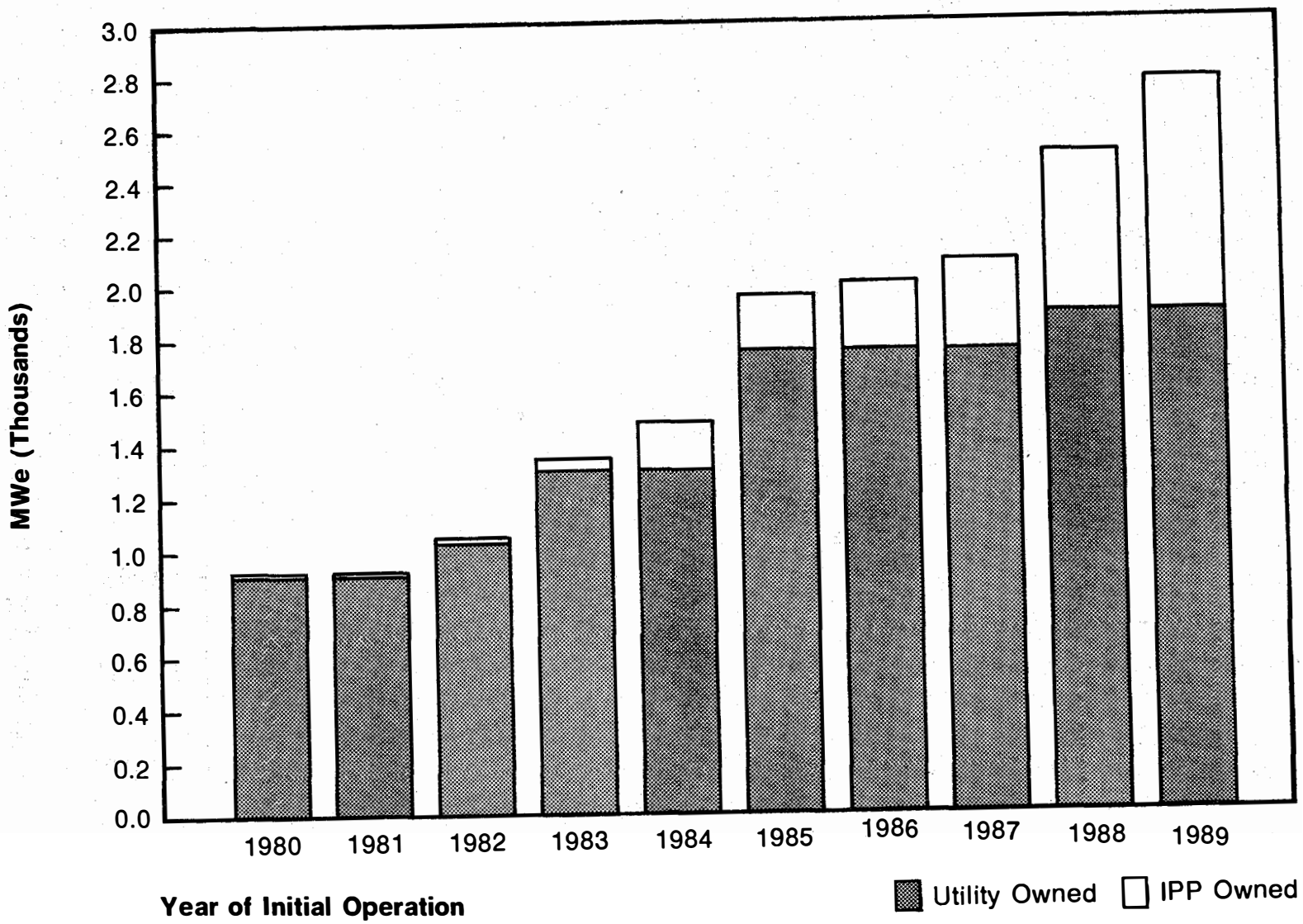


Figure 6. The U.S. Has Significant Hydrothermal Capacity Connected to the Grid

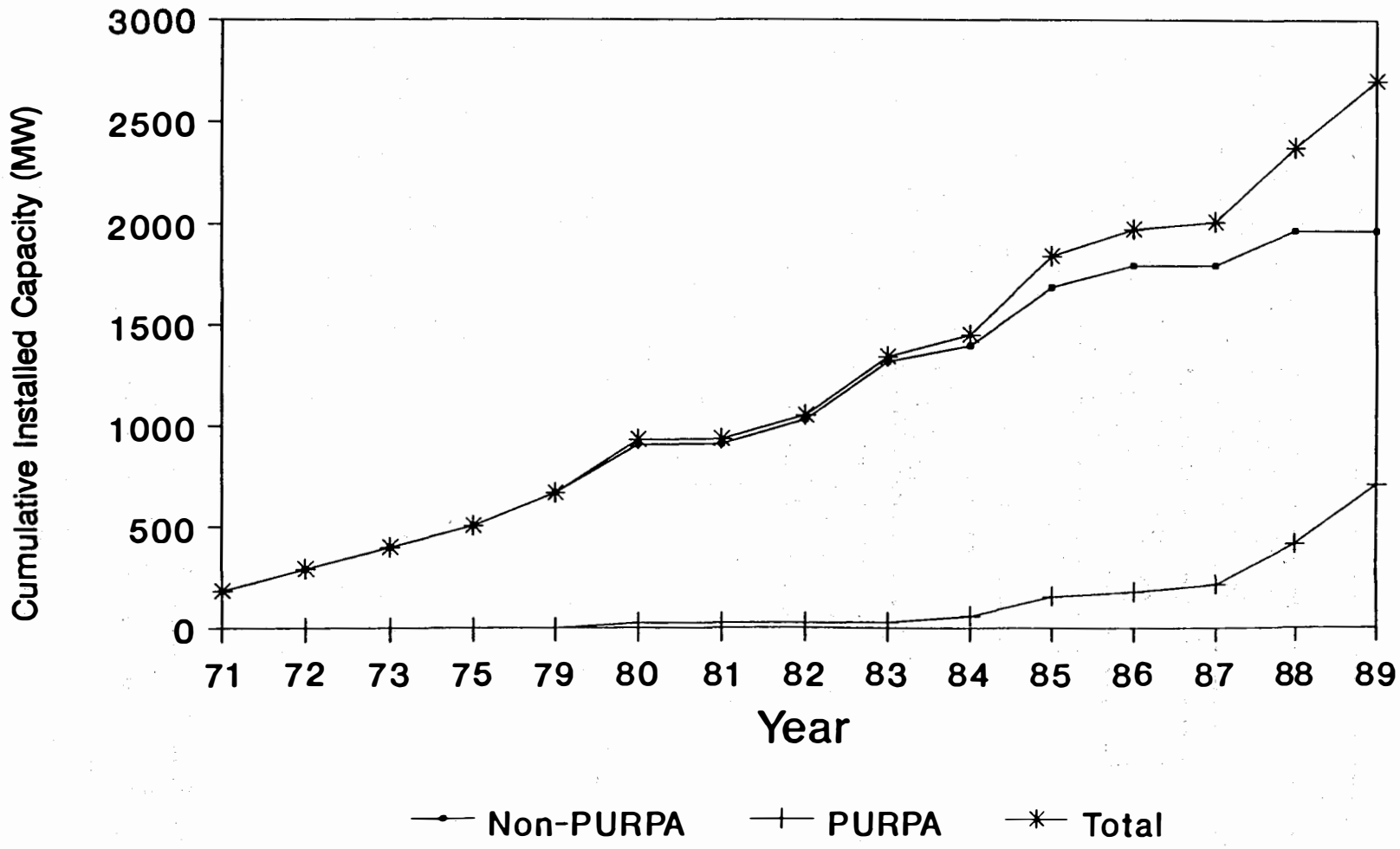


Figure 7. Effects of PURPA on Growth of U.S. Hydrothermal Electric Capacity

immediate, pressing problems. In recent years, DOE has assisted R&D efforts by industry through the formation of two industrial consortia, the Geothermal Drilling Organization (GDO) and the Geothermal Technology Organization (GTO). The GDO and GTO work on near-term problems of common interest to the member firms. At least half the cost of a research project is funded by interested members; DOE provides the remaining funds. The products of the research are commercialized for general use by industry. This approach to leveraging public and private R&D funds to advance technology has already succeeded in bringing several new products to the marketplace. Both the GDO and GTO are growing and gaining support throughout the industry.

1.5 Market Acceptance and Experience

At the time the federal Geothermal Energy R&D Program was initiated in 1971, less than 200 MWe of dry-steam generating capacity was in production at The Geysers, and the nation's first hot water demonstration plant was still nine years in the future. Hot brines from some reservoirs would scale production wells almost shut, corrode and erode turbine blades, and plug injection wells. Geothermal drilling costs were up to four or five times those of oil and gas drilling, yet drilling was necessary to identify, confirm, and characterize reservoirs in the absence of reliable geoscientific techniques adapted to geothermal conditions. No research into energy extraction from geopressured brines, hot dry rock, or magma had been conducted.

Today, many of the technical impediments have been removed or reduced, and a hydrothermal industry is well-established in the U.S., with nearly 2800 MWe of capacity installed in three states. Experience has extended far beyond The Geysers. At the end of 1989, 35 hot-water plants were in operation, accounting for over 800 MWe of capacity.

In particular, considerable development is taking place at the Salton Sea Known Geothermal Resource Area (KGRA) reservoir in the Imperial Valley of southern California. This development could not have occurred without the lessons learned at the cooperative government/industry Geothermal Loop Experimental Facility (GLEF) on handling brines that are eight times saltier than sea water. Experiments with crystallizer/clarifier technology at this facility in the late 1970's effectively opened an estimated 2,000 MWe capacity in the Imperial Valley to economic use. A 34 MWe dual-flash plant is now at the site of the GLEF.

Despite these achievements, significant technical problems remain. Many investors still view hydrothermal projects as high-risk ventures. Reliable estimates of reservoir productivity and lifetime, two key investment parameters, often are not available. Drilling costs remain well above petroleum industry averages. Inexpensive and dependable means of locating and confirming new resources, short of drilling, are lacking. An unexpected acceleration in degradation of the steam resource at The Geysers has contributed to investor uncertainty. Unless dealt with effectively, these problems may curtail future expansion of the market for hydrothermal electricity.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

A figure of merit is a number that rates the relative attractiveness of some aspect of a project or technology. The figures of merit listed here are some of the major technology performance criteria commonly used by industry and the DOE Geothermal R&D Program.

Overall System Figure of Merit:

- Levelized Cost of Energy (Cents/kWh) - This is the main figure of merit for hydrothermal electric systems. It includes estimates of the risk of project failure or partial failure due to uncertainties in reservoir and technology performance.

Key Figures of Merit:

To some extent, independent figures of merit can be estimated for hydrothermal "field technology" and "plant technology". When this is done, the dividing line should be drawn in terms of the ideal available work in the geothermal fluid at the power plant inlet, since the available work is highly sensitive to the temperature of the fluid. The field-related expenses then set an upper limit on the value of that work, regardless of conversion plant characteristics.

- Net Brine Effectiveness (Wh/lb of brine) - This describes the critical relationship between the power plant and the well system that supplies the plant. It is affected the most by reservoir temperature due to intrinsic thermodynamic factors, but is also influenced by power plant design. The higher this number, the less geothermal fluid is needed to make one kilowatt-hour.

- Capacity Factor (%) - The capacity factor is the amount of energy that a power plant produces, expressed as a percentage of the total amount that the plant would produce if it operated at rated capacity during the entire year. The factor is roughly equivalent to the percentage of time electricity is drawn from the generator and reflects the combination of power plant intrinsic availability and use of the plant for some fraction of that availability to meet electrical system demand.

- Installed Capital Cost ($/kW) - This includes all engineering, equipment, and construction costs to bring the system on line. In the Technology Characterizations, this does not include interest accrued during construction. This figure of merit is one relatively simple way to track technology improvements over time.

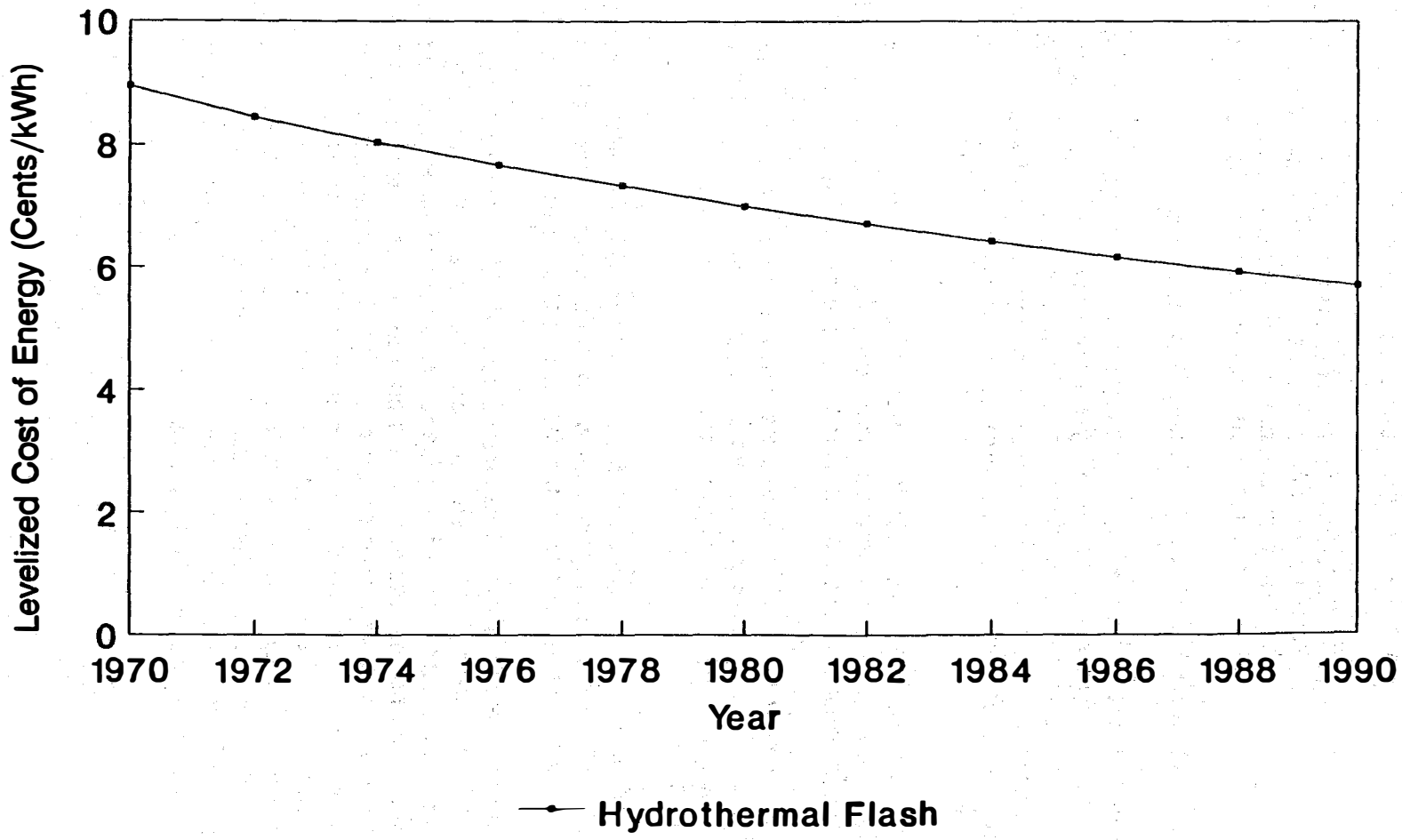


Figure 8. Estimated Improvement in Hydrothermal Flash Technology

- Operation and Maintenance Cost ($/kW/Year) - This includes all costs to keep the well field and plant operating.

- Reservoir Risk, Percent of Electricity Cost - This is an estimate of the percentage of electricity cost that can be attributed to uncertainties about long-term performance of the geothermal reservoir. It reflects the capability of reservoir analysis and how well that analysis is applied.

2.2 Historical Technology Trends/Current Status

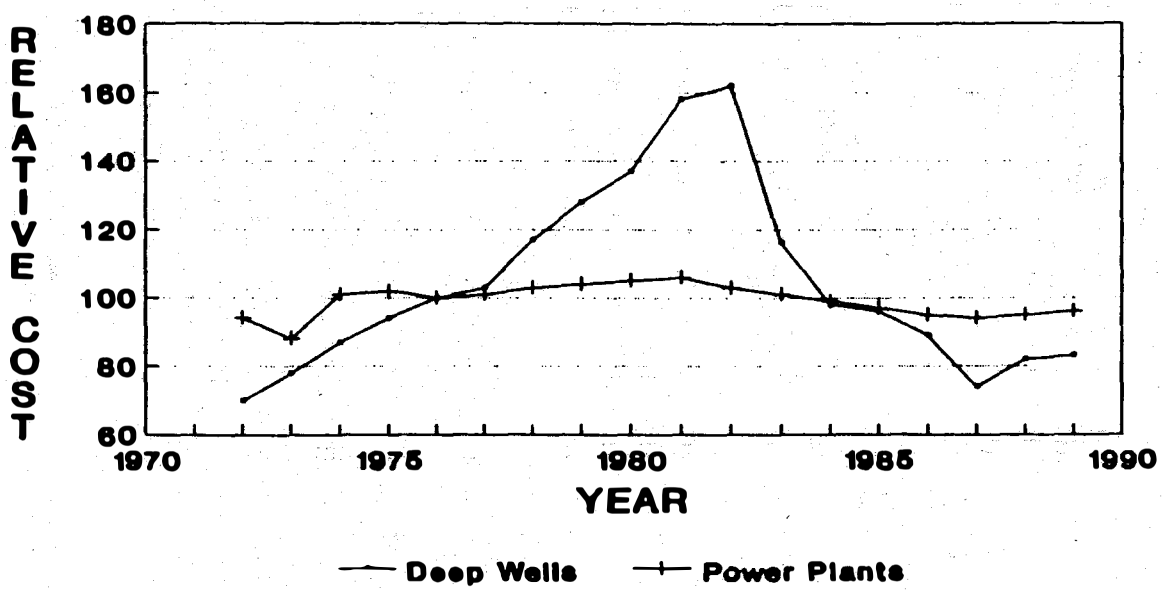
Over the last decade, a trend toward smaller generating systems has developed. Most of the turbine-generators at The Geysers are sized at 50 to 100 MWe. But many of the newer units at hot-water plants range in size from 1.5 to 50 MWe. This is due in part to size limitations under PURPA and the recent advent of small, pre-fabricated modules. Investor uncertainty over long-term reservoir performance may also contribute to this trend.

As discussed in Section 1.2, there is a trend toward integrated field/plant development, where one entity owns both the production field and power plant. This should lead to more rational economic optimization of field-plant operations and long-term production.

The Geothermal Division estimates that the overall system figure of merit (levelized cost of energy) has changed, as shown in Figure 8, over the past 20 years. System availability appears to have increased, but trends are not obvious because of the small statistical data base.

The power purchase contracts for most of the PURPA geothermal plants built in the mid-1980's are set at capacity factors of 80 percent. Current hydrothermal technology meets that level of performance easily, and the trend is toward higher capacity factors.

A planned availability and capacity factor of 100 percent has been built into the Santa Fe #1 dry steam plant at The Geysers. Given a design capacity of 80 MWe, the turbine-generator system is configured as a pair of units, each producing either 40 or 80 MWe. The normal mode is to run both at 40 MW each. During outages of one unit, the other can be operated at full capacity. The economics of this approach, as documented by the plant's design engineers, Stone and Webster, were reviewed for applicability to hot-water plants. The technical requirements and economics are such that similar design redundancy will apply readily to mature flash-steam plants and almost certainly to modular binary plants. Therefore, it is reasonable to project that the capacity factors of such plants (averaged and aggregated across many new plants) will gradually increase to very high levels in the future.



SOURCE: MIT Composite Cost Indexes; Tester & Herzog, 1989.

Figure 9. Deep Well Drilling Costs in U.S.

Other trends in technology include a decrease in geothermal well costs, increased drilling effectiveness, temperature-hardening of critical materials, and a reduction in lead time for opening new reservoirs.

- The indices for deep well drilling costs and power plant construction in the U.S. are given in Figure 9. The decrease in deep well costs parallels improvements made in the effectiveness of geothermal drilling technology, as shown in Figure 10. The extent to which these improvements influenced costs cannot be determined quantitatively.

- The useful temperatures for both wellbore cements and elastomeric sealing materials have been increased markedly over the last few years (see Figures 11 and 12). These improvements are now used extensively in both geothermal and oil/gas fields.

- The mean time between initial discovery of a resource and the first power production has decreased over the past two decades from about 20 years to about 6 to 8 years [4] (Figure 13). By installing relatively small (5 to 15 MWe net) plants, operators are able to test a new reservoir for its capability to support larger capacities while generating income to reduce the carrying costs for discovery expenses.

Additional significant improvements in hydrothermal electric technology have occurred since early 1986, the date of the hydrothermal technology performance and cost baseline established by the Geothermal Division. For example, the annual service cost for downhole production pumps has been reduced to 43% of the 1986 baseline value, effective end of 1987; reservoir confirmation costs for the Salton Sea area have been decreased by 20%, effective mid-1988; the cost of sludge disposal from Salton Sea flash plants has been reduced to 40% of the 1986 nominal cost; and the service life of production liners at the Salton Sea field has been increased to 30 years, from a nominal 1 year, at a nine-fold increase in the cost of the liner.

Other important improvements that are not well quantified have also been made in the mid- and late 1980's. These advances include the development of the crystallizer-clarifier to prevent siliceous sludges from clogging injection wells; high-temperature wellbore sensors for temperature, pressure, and other variables; hydrogen sulfide abatement systems; long-bladed, high-efficiency turbines; automated power plant controls; automated field production controls; and upstream stripping of noncondensible gases via steam generators or reboilers.

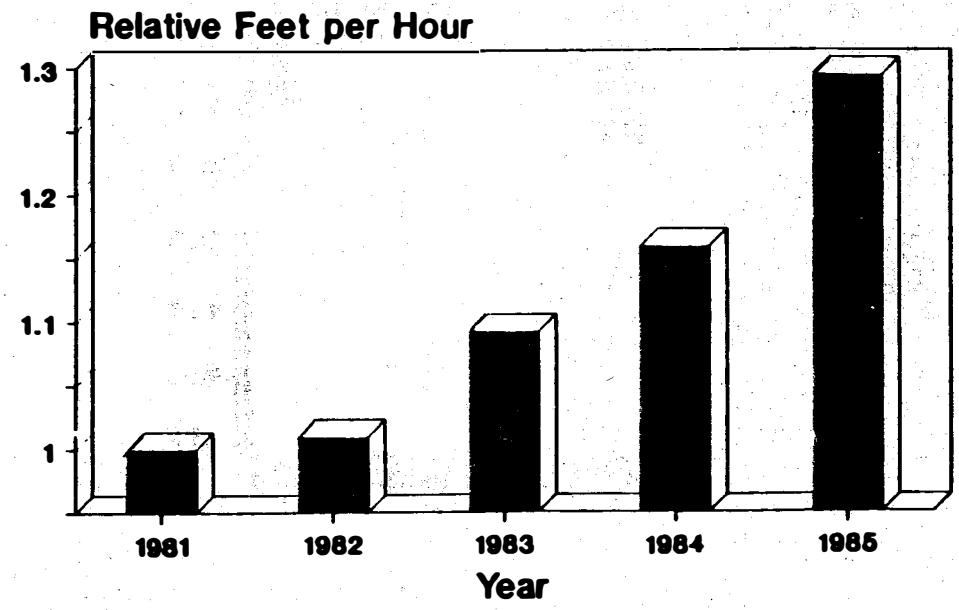
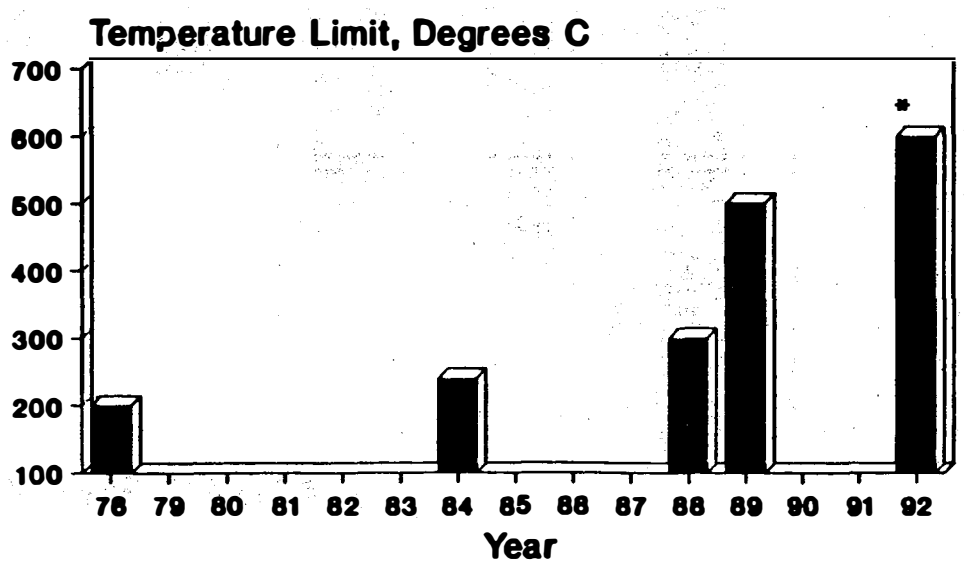


Figure 10. Technology Improvement: Drilling Effectiveness at the Geysers



* Temperature projection by BNL

Figure 11. Hydrothermal Technology Improvements in Well Cements

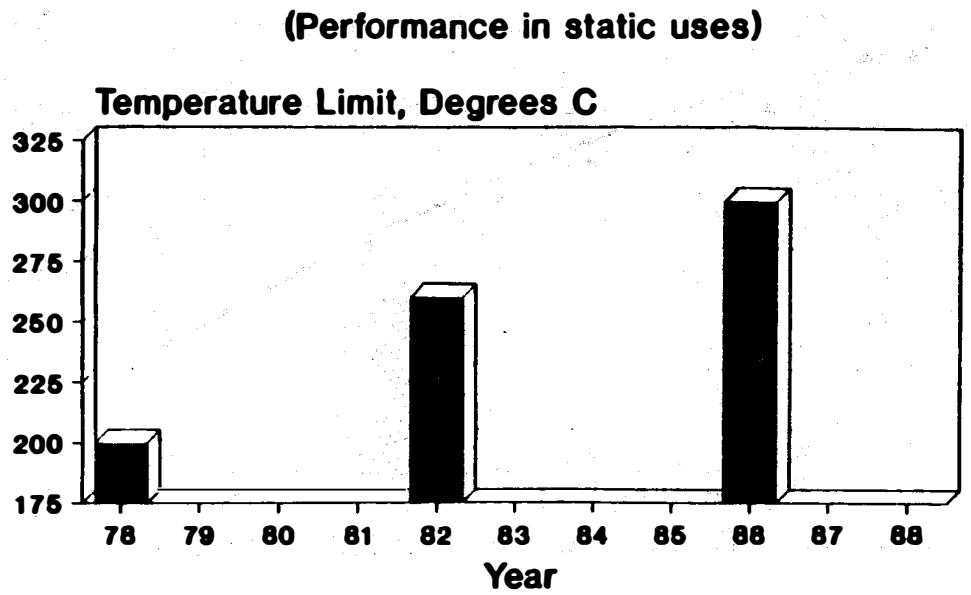
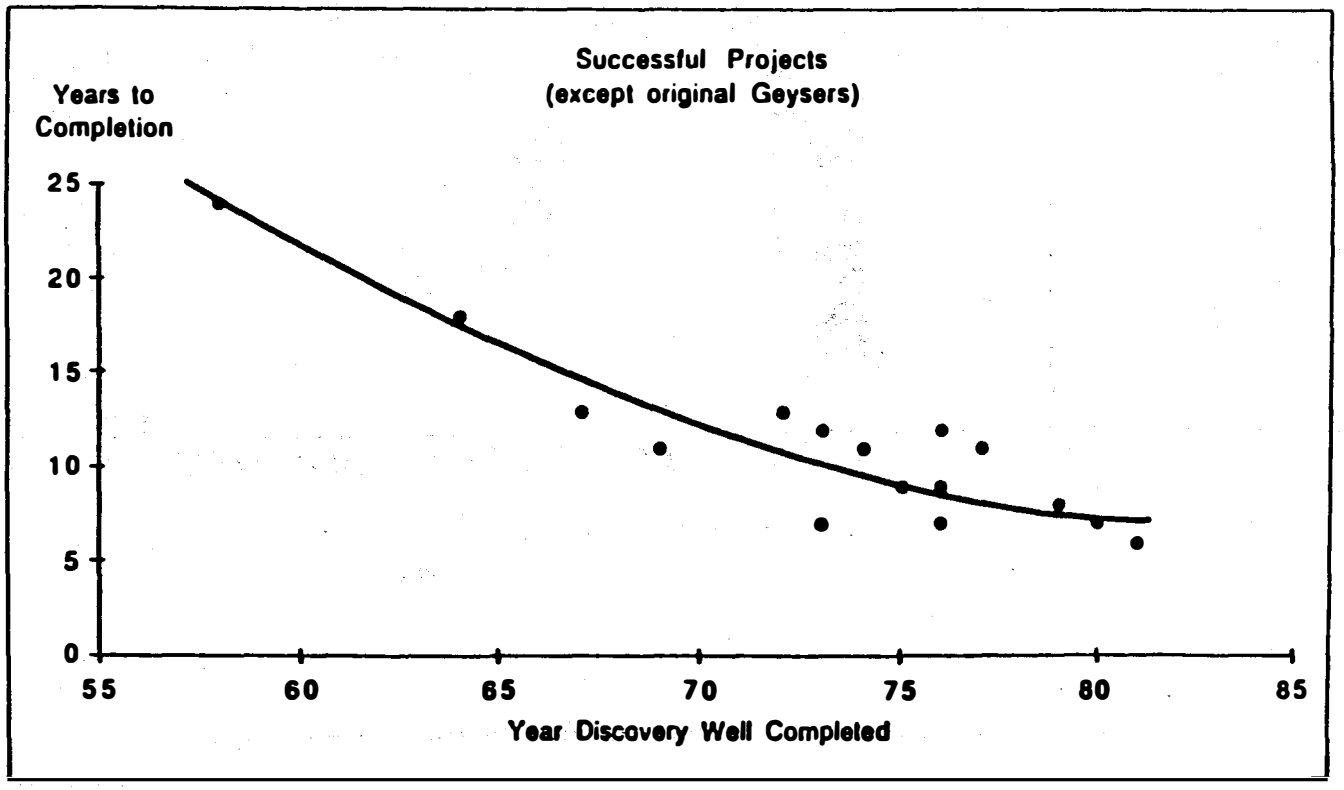


Figure 12. Hydrothermal Technology Improvements in Elastomers



Source: Geothermal Resources Council Bulletin, August 1988.

Figure 13. Improvements in Pace of Reservoir Opening for Power Production

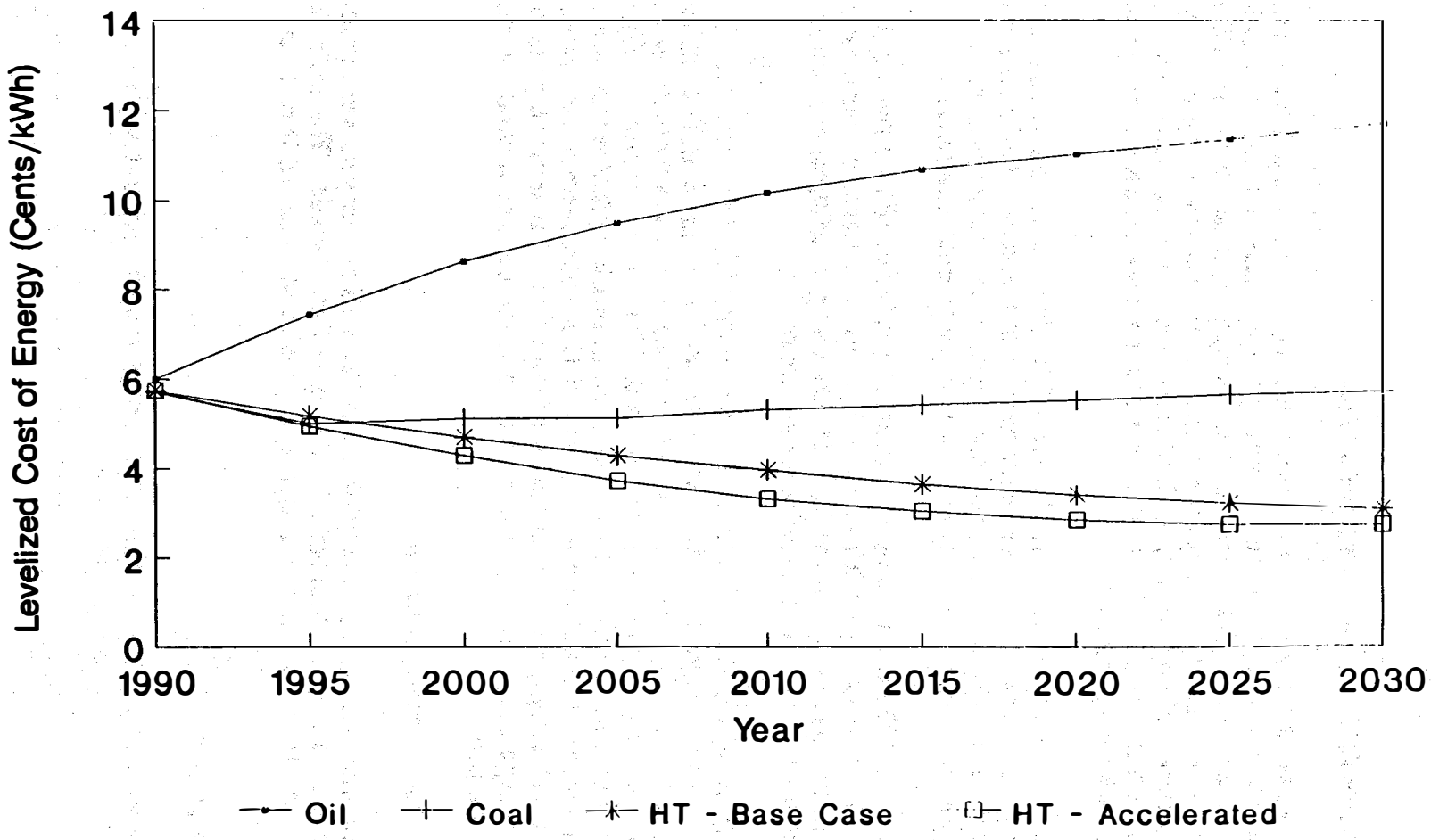


Figure 14. Baseload Electric Technologies Base and Accelerated R&D Cases

3.0 COST/PERFORMANCE PROJECTIONS

The projected improvements in the cost of electricity using hydrothermal technology are plotted in Figure 14. The gradual decline for the base case costs and the somewhat steeper decline and lower ending cost for the accelerated case are the estimated average costs for specific amounts of new hydrothermal electric capacity in western regions of the U.S. A number of good-quality hydrothermal reservoirs are competitive now with coal- and oil-fueled plants. Other hydrothermal reservoirs of lesser quality will become economic as technology improves.

The base case scenario assumes that the annual funding level remains at the same level initially with modest increases in the latter part of this decade. The base case capacities (in units of MWe for 30 years) are predicated upon projected current trends in the rates of technology improvement and discovery of new geothermal prospects.

The accelerated R&D case assumes an increase by a factor of 2 in funding level compared to the base case. Additional new capacity in the accelerated case is expected to result from an acceleration in the pace of technology development coupled with an increase in industry's rate of discovering new resources.

The base case cost projections in Figure 14 were derived in part from the illustrative flash plant characterized in the hydrothermal section of Renewable Energy Technology Characterizations [5]. That plant is relatively expensive but was selected to show how certain brine-handling issues have been resolved. The cost projections in Figure 14 include the added consideration of the quality of available hydrothermal resources. They were developed from a detailed analysis of U.S. hydrothermal resources, current hydrothermal technology, and the feasibility of improving that technology through R&D [6]. These average costs are less, as expected, than the costs estimated for the illustrative flash plant.

3.1 Base Case Funding Scenario

The base case assumes initial funding of about $22 million per year with gradual increases leading to almost a doubling by the end of the decade. The technology improvements projected under this scenario are believed to be achievable at this funding level.

3.1.1 Research Activities

The research project portfolio for the base case is founded on industry's current major needs.

Table 1. Cost and Performance Details, Base Case Scenario (a)

(1989 constant dollars)

	1990	1995	2000	2005	2010	2015	2020	2025	2030
CAPITAL COSTS, $/KW									
Major Components									
Discovery	241	219	197	175	153	131	109	87	65
Well Field	520	490	461	431	402	372	343	313	284
Power Plant	1410	1436	1463	1489	1515	1542	1568	1568	1568
Total Direct Cost	2171	2146	2121	2096	2070	2045	2020	1969	1917
Contingency (b)	257	227	199	171	143	116	90	64	38
Total Installed Cost	2428	2373	2319	2266	2214	2162	2110	2032	1956
O & M COSTS, $/KW/yr									
Well Field	82	74	66	58	51	45	39	33	28
Power Plant	119	98	83	72	65	60	57	54	52
Total, Fixed O&M	201	171	148	131	117	105	96	87	80
CAPACITY FACTOR, Percent									
	81	83	85	88	90	93	95	95	95

NOTES:

(a) = Based on a design to accommodate hypersaline, high-temperature brines.
(b) = Contingency included specifically to cover reservoir uncertainties.

Industry's highest priority need concerns the unexpected drop in productivity (pressure, steam flow), coupled with the appearance of corrosive hydrogen chloride, in some areas of The Geysers field. Solutions to these problems will have to be found before the fields shut-in capacity (>400 MWe) can return to production.

The lack of techniques to locate and characterize fractures in underground rock formations significantly inhibits industry's ability to tap consistently the areas of greatest fluid productivity. The result is that many reservoirs have not reached full production potential because they cannot be sufficiently characterized to apply cost-effective exploitation strategies.

Effective means are similarly lacking for identifying hydrothermal systems in regions where shallow cool groundwater effectively masks the underlying heat. This is particularly important in the Cascades Range of the Pacific Northwest where the presence of a very large hydrothermal resource is suspected.

Injection of spent geothermal fluids back to the production zone is practiced by virtually all field operators, both as a means of acceptable disposal and to prevent potential land surface subsidence due to the withdrawal of fluids. If done properly, injection can help to maintain reservoir pressure, thereby extending the life of the field. Injection wells must be located so that premature cooling of fluids in the production zones will not occur.

Hydrothermal well costs have declined significantly at some geothermal fields; the most economical are estimated to be only one and a half times as expensive as those of oil and gas drilling. However, at other fields, well costs still constitute a major deterrent to increased development -- for example, titanium well casing at $1,000 per foot is being used in the harsh Salton Sea environment.

While large-scale binary cycle technology has been tested at a government/industry 45 MWe plant, this technology is marginally economic for commercial use. Further improvements in efficiency are needed to fully exploit intermediate-temperature reservoirs.

In the past decade, technically satisfactory and economical solutions have been found for many of the adverse interactions between hydrothermal brines and energy extraction equipment and materials that seemed intractable in the early 1970's. However, since the remaining adverse interactions differ from reservoir to reservoir, methods to predict or detect them as they occur are needed, along with reductions in the cost of materials that will withstand them.

3.1.2 Base Case Technology Development Scenario

The details of the hydrothermal energy cost projections for the base case are shown in Table 1. They are the cost and capacity factor values for the illustrative dual flash plant

in Renewable Energy Technology Characterizations. System parameters assumed for that flash plant are shown in Table 2.

Table 2. Hydrothermal (Hot Water) System Description

(1986 Technology Baseline)

System Type	Dual Flash (a)
System Design Capacity, MW net	50
Average Well Depth, Feet:	6000
Reservoir Saturated Temperature, °C:	266
Total Dissolved Solids, Percent:	32
Net Brine Effectiveness, Watthour/lb:	7.8
Producer Well Average Flow, Klb/hr:	400
Financing Assumptions	Utility-Owned

Notes:

(a) The system described here is similar to Magma Power Company's "Vulcan" plant at Niland, California.

The reasonableness of these cost-improvement curves is supported, for the base case, by two points of view:

- Detailed quantitative statements of research program objectives, originated by research program managers and integrated through a systematic cost-of-energy computer model, IM-GEO. These objectives suggest a reduction of 25 to 35% in the cost of energy across a variety of reservoirs during the mid-term.

- Quantitative analysis of possible cost reductions through "learning" curves or "experience" effects. These suggest that a reduction on the order of 50% in the cost of energy could be achieved sometime in the early part of the next century [7].

3.2 Accelerated Hydrothermal R&D Funding Scenario

The accelerated R&D funding scenario assumes about double the funding of the base case.

3.2.1 Research Activities

The accelerated R&D case assumes that research prescribed under the base case will be accomplished sooner and adopted by industry at a faster pace.

Additional specialized R&D initiatives beyond the base case would include:

- Advanced Exploration Methodology - This cost-shared initiative would examine the latest, most sensitive geoscientific technologies (e.g., seismic refraction, geotomography, remote sensing) that can be used to identify hidden hydrothermal systems. They would be evaluated to judge their merits, both technical and economic, as exploratory tools. In addition, natural phenomena (optical, electromagnetic, gravitational, chemical, and biological) would be studied to determine whether they offer promise for further development as innovative exploration techniques. Advanced methods of data processing and interpretation would be applied to extract holistic information from a combined set of exploratory observations. The final methodology (tools and techniques) would be field tested and verified in cooperation with industry.

- Innovative Hard Rock Drilling System - In order to make substantial reductions in the cost of geothermal drilling, this initiative would adapt the latest cost-saving innovations from other industries. At a minimum, these would include high-angle drilling to improve the dry hole ratio in fractured reservoirs and continuous coring to reduce costs and increase data returns from exploratory wells. New, untried approaches would be evaluated for their technical and economic feasibility. Critical supporting technology, such as resistant materials and coatings, bonding materials, real-time information flow, and control systems, would be upgraded. At least one complete prototype system would be built and tested with industry cost-sharing.

- Modular Energy Conversion System - In a cooperative cost-shared effort, DOE and industry would develop an energy conversion unit based on advanced technology. The system would be designed for adaptability to a wide range of geothermal reservoir sizes and characteristics, for transportability, and for factory fabrication and on-site assembly. The project would include the design, bench testing, fabrication, and field testing of a prototype unit. The participating companies would acquire or retain proprietary rights to the design.

- Geothermal Heat Pump Emplacement System - This initiative would create a quick and inexpensive method of drilling shallow vertical heat exchange wells for heat pump applications. Target specifications for the system would be one-day installation of three, 30-meter wells to service

Table 3. System Cost Estimates, Based on Supply Analysis

BASE CASE:

Year	Cap Cost ($/kW)	OM Fixed ($/kW/yr)	Cap Fac (%)	Level. COE (cents/kWh)
1990	2178	181	81	5.74
1995	2136	154	83	5.17
2000	2087	133	85	4.70
2005	2039	118	88	4.28
2010	1993	105	90	3.96
2015	1946	95	93	3.64
2020	1899	86	95	3.41
2025	1829	78	95	3.23
2030	1760	72	95	3.07

ACCELERATED CASE:

Year	Cap Cost ($/kW)	OM Fixed ($/kW/yr)	Cap Fac (%)	Level. COE (cents/kWh)
1990	2178	181	81	5.74
1995	2041	147	83	4.94
2000	1902	121	85	4.29
2005	1767	102	88	3.71
2010	1661	88	90	3.30
2015	1622	79	93	3.04
2020	1583	72	95	2.84
2025	1565	65	95	2.74
2030	1565	64	95	2.72

one residence. Supporting technology development would include improved in-ground heat exchangers, methods to measure critical parameters in situ, and control systems to maintain peak performance. The final integrated system would be tested by industry under a range of operating conditions.

- Cooperative Assistance to Industry - This initiative would provide a variety of technological tools and economic incentives for U.S. industry to compete in foreign (and domestic) energy markets. Under cost-sharing arrangements, modern technology, including the products of other initiatives, would be applied to facilitate development of new resources, especially those in other countries. CORECT would be used as a primary conduit for exporting U.S. technology. Prospective regions thought to contain hidden hydrothermal resources would be explored more thoroughly and at an accelerated pace.

3.2.2 Accelerated R&D Technology Development Scenario

The details of the hydrothermal energy cost projections for the accelerated R&D case are shown in Table 3 and Table 4. The base case values are included for comparison. These values were prepared and used for market penetration analyses within DOE during May through August, 1990, and are the values plotted in Figure 14.

Additional information concerning the rationale for these expected improvements can be found in Section 4. Technology transfer and cooperative assistance programs are expected to speed up industry's adoption of the improvements and produce feedback on needs for further improvements.

Table 4. Electric Capacities Estimated to be Available at Stated Average Costs

	Net GWe (for 30 Years)	
Region	**Base Case**	**Accelerated Case**
6	10	15
7	0	0
8	10	15
9	20	30
10	20	30

3.3 Beyond Hydrothermal Funding Scenario

The exploitation of hot dry rock and geopressured resources may occur if federal geothermal research is markedly increased beyond the hydrothermal accelerated R&D case. The incentives for shifting to hot dry rock include: (1) the resource base is widespread and exceeds 160,000 quads [1]; (2) if viable, the technology is probably economic today in a few areas of high temperature gradient; and (3) at least five other nations are actively pursuing hot dry rock research. Geopressured resources, which contain various amounts of dissolved methane, are estimated at more than 73,000 quads of thermal energy and 5,700 quads of energy from methane [1]. The higher temperature fluids have the potential for power generation; the lower temperature fluids may be utilized in direct heat applications, such as thermal enhanced oil recovery. The entrained methane gas may be separated from the fluid and used to generate electricity or sold to a gas pipeline company. While some direct applications appear attractive, the advancement of geopressured resources largely depends on the economics of natural gas. Hot dry rock, on the other hand, is more sensitive to improvements in geothermal technology. For this reason, the following case specifically addresses only hot dry rock technology.

The case assumes funding of about 3.5 times the amount projected for the base case over the next decade. Much of the increase is planned for cost-shared, cooperative demonstrations of advanced geothermal technology.

3.3.1 Research Activities

Early research under this case would investigate the feasibility of drilling large diameter wells in deep, hot crystalline rocks at one-half to a one-third of current costs. The research planned for the hydrothermal accelerated case to develop an innovative drilling system would be intensified. Accelerated development would require expensive reservoir development and demonstration projects and at least one commercial-scale power plant project, that would be federal/state/private cost-shared. Cooperation would be sought with other countries (e.g., Japan) involved in hot dry rock research.

The final target technology improvements are expected to be great enough that at least some resources in all regions of the U.S. would be economic to develop. Initially, however, only the highest-gradient areas (>70°C/km) would be attractive targets. These areas lie in the western states.

Early hot dry rock (HDR) development is assumed to occur in the vicinity of developed hydrothermal fields, either as secondary recovery of heat within the naturally fractured part of the reservoir, or as primary heat extraction from deep, unfractured hot rock. This assumption minimizes initial exploration and confirmation costs for applications of the technology.

3.3.2 Beyond Hydrothermal Development Scenario

System costs are taken from a study by Tester and Herzog [8]. The general resource assumptions are shown in Table 5. The financial assumptions are the same as those used in Technology Characterizations, except that system life is 20 years. Construction time is assumed to be 2.5 years at the mature stage of technology development. The estimated cost of electricity, in 1989 constant dollars, is shown in Table 6. Much shorter construction times are likely to occur as technology matures.

Only a portion of the economic resource will be developable, due to constraints of market factors, physical limitations, and socioeconomic factors. This analysis assumes that about 10 percent of the economic HDR resource would be practicable to develop. (Some experts estimated the "developable fraction" to be as high as 30 percent.) At the 10 percent assumption, the full (technically feasible) potential is about 19,000 GWe. Installing 1,000 GWe of HDR baseload power plants would use about 0.05% of the U.S. land surface (1500 square miles).

The cost curve results are shown in Table 7. The results represent average costs across a resource that could support at least 3,800 GWe of installed capacity in the western states with a system lifetime of 20 years. For comparison, the current U.S. installed electric capacity of all types is about 600 GWe.

Table 5. Technical Assumptions for Hot Dry Rock, Economic Supply Analysis

Class	Temperature Gradient Assumption, Deg C/km: Mapped Contour	Temperature Gradient Assumption, Deg C/km: Power Plant Design Datum	Heat to Electric Convers. Effic., Percent	Thickness of Mined Layer, Meters	Maximum Capacity Density, MWe/Sq.Mi.
1:	<20	20	9	500	39
2:	20 - 30	30	12	500	52
3:	30 - 50	40	17	500	73
4:	50 - 70	60	17	1,000	147
5:	>70	80	17	1,500	220

Table 6. Estimated Hot Dry Rock Electricity Cost, Cents/kWh

TEMP-GRAD. CLASS	Technology Stage			
	TODAY	MATURE	DOUBLET[a]	TRIPLET[a]
1.	106.3	69.7	50.2	39.2
2.	30.8	19.3	13.0	10.5
3.	15.2	9.8	6.8	5.7
4.	7.9	5.5	4.0	3.6
5.	6.0	4.5	3.4	3.2

Notes:

(a) "Doublet" and "Triplet" are optimized patterns for connecting wells [8].

Table 7. Technology Characterization Cost Curve for Hot Dry Rock

Year	Capital	O&M	Cents/kWh
1990	3,451	156	8.2
1995	3,451	156	8.2
2000	3,189	145	7.5
2005	2,667	122	6.3
2010	2,206	106	5.3
2015	1,807	98	4.5
2020	1,582	87	4.0
2025	1,559	81	3.8
2030	1,543	77	3.7

4.0 RATIONALE FOR TECHNOLOGY IMPROVEMENTS

The relationship of hydrothermal electric technology to reservoir properties is complex. Some of the main paths through which hydrothermal reservoir characteristics affect the cost of electricity are shown in Figure 15.

Many of the improvements that remain to be made for hydrothermal technology will depend on improving the general ability to measure and predict reservoir characteristics. Other improvements will come from advances in the mechanical components of energy extraction and conversion technology.

The three states of technology maturity presented are:

- Current Technology - Hydrothermal technology in use as of the late 1980's.
- Mid-Term Target Technology - That technology expected to result from the geothermal R&D Program, as currently planned through the 1990's.
- Long-Term or Ideal Target - Technology that could likely be achieved over a long period through a combination of intense applied research and much learning from industry experience.

The "Mid-Term Target Technology" is identical to the mid-term (2000 - 2005) expectation for the base case. The "Long-Term Target Technology" is the 2020 - 2030 expectation from the accelerated case.

4.1 Current Technology (1990)

The technology assumed for 1990 is mainly that defined by the technology assessment for the IM-GEO model [9,10]. IM-GEO presents users with the results of cost/risk analyses for eight plant-site combinations that represent a range of typical hydrothermal electric projects. The basic data for these analyses were gathered from industry sources at 10 operating hot water plants. Data on exploration, drilling, and other ancillary activities were provided by contacting various geothermal service organizations. Thus, IM-GEO gives a baseline condition of hydrothermal technology as of 1986. Modest improvements attained since then via federal and industry innovation successes have been added to bring the technology baseline up to the present.

IM-GEO, in part, emphasizes a novel and detailed analysis of how financial risk (from the viewpoint of investor or lender) is affected by uncertainties in the measurement and prediction of reservoir performance. This model has led to an improved ability to analyze the long-term effects and direct economic benefits of all geothermal research activities. Reservoir technology research can now be evaluated on a basis comparable to that traditionally used for estimating the future economic effects of improved drilling and power plant technology.

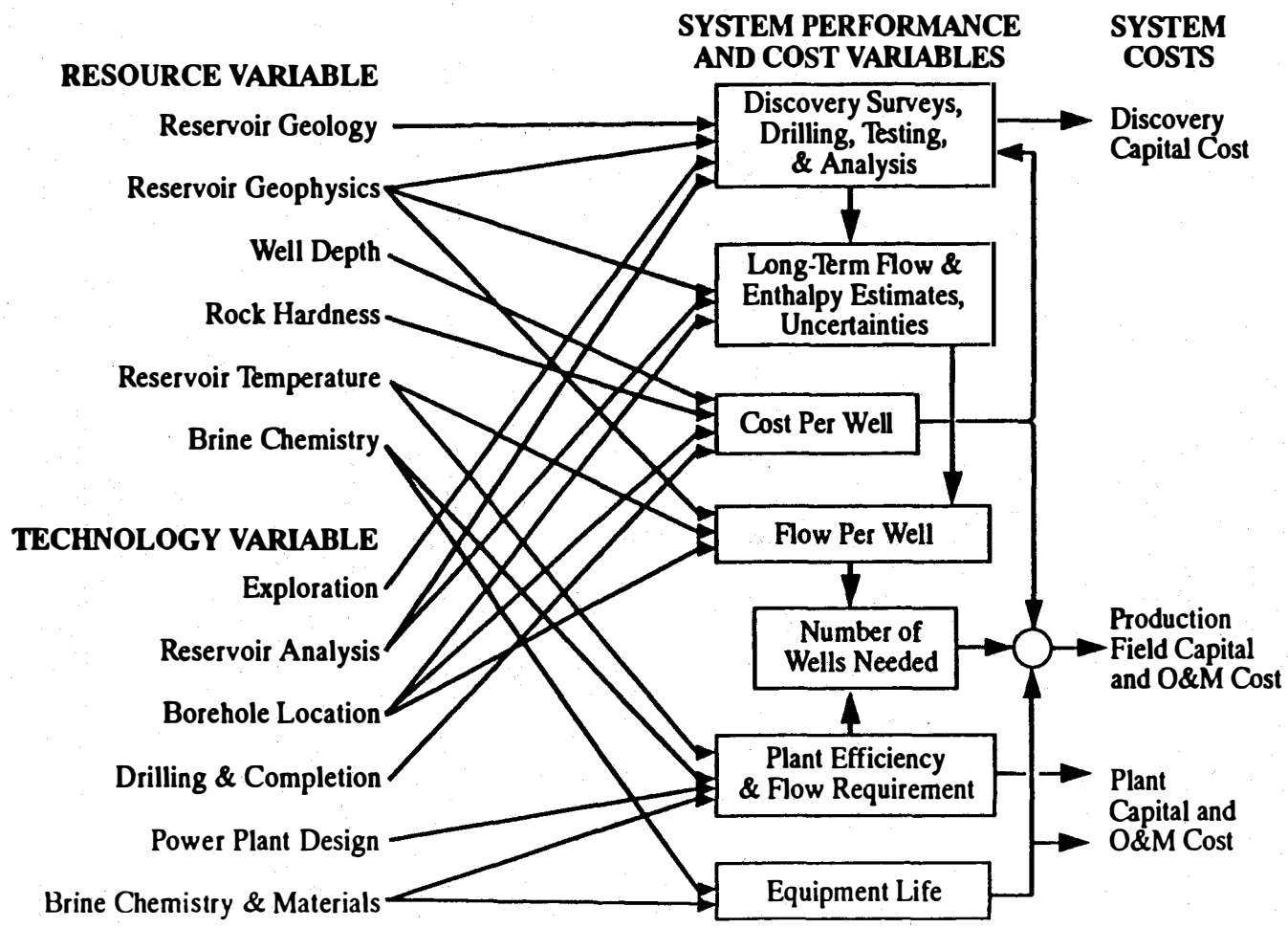


Figure 15. Impact Points of Reservoir and Technology Variables on Hydrothermal System Costs

Current hydrothermal technology includes major spinoffs to other use sectors. These spinoffs are important because they demonstrate that the Program has selected technology-improvement targets that are attainable and significant. In particular, spinoffs from geothermal drilling technology are important because the geothermal drilling market is small compared to that for oil and gas, and geothermal equipment is usually not economical to manufacture unless broader applications exist in oil and gas drilling. The following three examples from the Department's research program of the 1980's illustrate the importance and benefits of spinoffs:

- Polycrystalline diamond compact (PDC) drill bits. These bits drill 3 to 5 times faster in many formations and with longer lifetimes than standard roller-cone bits. Sandia National Laboratories has estimated that PDC bits now account for roughly $300 to $500 million per year in sales to oil and gas drillers worldwide.

- EDPM (Y-267) elastomer. This high-temperature, rubber-like sealing material was developed by Brookhaven National Laboratory and L'Garde Corporation. EDPM (Y-267) enabled many existing drill bit designs to be used at high temperatures, without redesigning critical seals. The material has other uses such as in downhole packers for pressurizing rock formations. EDPM (Y-267) is now used extensively in tertiary oil-recovery applications, and in chemical and nuclear plants.

- High-temperature electronic components. Sandia has successfully adapted electronic components from the nuclear weapons program to high-temperature environments. These devices, such as amplifiers, are now used in many oil and gas downhole measurement tools made by drilling service companies. They are cost effective in most very deep wells, where elevated temperatures always pose equipment survivability problems.

These examples demonstrate the general utility of past geothermal technology improvements, and the successful transfer of technology to industry. They portend the benefits future improvements may bring.

4.2 Base-Case Projections (1995-2005)

The base case assumes that current technology improves at a pace and in a direction established over the last 2-3 years. With respect to hydrothermal technology, that pace and direction are expressed in terms of the technical research objectives that the Geothermal Division (GD) of the Department of Energy has established to guide its research planning and management [11].

The Program's technical objectives are defined on three distinct levels. Level I objectives are associated with geothermal resource categories (e.g., geopressured) and

provide a target for decreasing the total cost of electric power generated from a particular type of resource. Level II objectives address incremental improvements in the cost and/or performance of major system components. Level III objectives identify individual research activity targets for improvements in the cost, efficiency, and dependability of materials, tools, equipment, tests, and processes related to major system components.

The achievement of Level I objectives depends on the achievement of the Level II and Level III objectives. The Level III objectives and associated research activities are the most dynamic part of the research program. All of the base case objectives are expected to be attained during the period 1995 to 2005. However, the full impact of the improvements may not be felt by industry for at least five years.

The following sections present objectives in technology improvements for the three major areas of hydrothermal R&D: Reservoir Technology, Hard Rock Penetration, and Conversion Technology.

Reservoir Technology

This area deals with reducing the risks associated with finding, confirming, and producing hydrothermal resources. Improvements expected to be gained through R&D in this area are:

- Exploration - The Cascade Range of the Pacific Northwest is considered by many experts as a hydrothermal province with major potential. But exploratory efforts by industry have failed to uncover that potential. Government/industry cooperative efforts will lead to better understanding of the nature of hydrothermal resources in the Cascades. This activity is expected to increase the success ratio of wildcat exploration wells, especially those in frontier areas, such as the Cascades, by 20%.

- Reservoir Analysis - The products of this work are the analytic and interpretive tools needed by industry to determine reservoir characteristics and performance with greater certainty. These tools include geophysical instruments to measure reservoir parameters (e.g., temperature, porosity, permeability) as well as models that simulate reservoir behavior. With improved reservoir analysis, uncertainties are reduced, and project costs will fall. The expected improvements will:

  Reduce the number of wells needed to define the resource by 33%.

  By increasing the accuracy and precision of information used by models of reservoir characteristics and performance, decrease uncertainties in forecasting short-term and long-term reservoir

changes in fluid temperature, pressure, flow rate, and chemistry by 10%.

Reduce uncertainties in predictions of reservoir capacity by 15%.

By improving reservoir evaluation methods, decrease uncertainties in forecasting short-term and long-term reservoir changes in fluid temperature, pressure, flow rate, and chemistry by 15%.

Reduce the number of wells needed to evaluate a reservoir by 10%.

- Brine Injection - Recent pressure declines at The Geysers steam field exemplify the need to conserve hydrothermal liquids with an injection program. Some injection programs at hot water fields have achieved only marginal success. This work provides the means to evaluate injection alternatives and devise strategies that will maintain reservoir integrity (i.e., productivity and lifetime). The expected improvement will:

  Increase the success ratio of in-fill wells for production and injection, i.e., decrease the dry-hole ratio for in-fill wells for production and injection by 33%.

  Improve methods for positioning and designing geothermal production and injection wells in order to reduce the aggregate cost of wells by 15%.

  Improve reservoir monitoring methods to decrease uncertainties in forecasting short-term and long-term reservoir changes in fluid temperature, pressure, flow rate, and chemistry by 10%.

  Reduce the number of low-flow and short-lived production and injection wells drilled after production begins by 15%.

  Improve the efficiency of the production and injection schemes to reduce the number of make-up wells by 10%.

  Reduce uncertainties related to long-term reservoir changes in fluid temperature and injection breakthrough by 10%.

  Reduce the number and severity of unexpected environmental problems, especially those related to potential seismicity and subsidence.

Hard Rock Penetration

Wells constitute 30-50% of the cost of a hydrothermal power plant. Whereas Reservoir Technology seeks to reduce risk by minimizing the investment in drilling wells, Hard Rock Penetration deals with reducing the cost of individual wells. The expected improvements associated with drilling technology include:

- Lost Circulation Control - Loss of drilling fluids into fractured rock can effectively double drilling costs due to downtime. Special drilling fluids (e.g., foams, cements) and emplacement tools suited to hydrothermal environments will help reduce or curtail those losses. Costs associated with lost circulation episodes will be reduced by 30%.

- Rock Penetration Mechanics - This area will produce integrated systems for (1) increasing the efficiency of collecting core from deep geothermal wells and (2) reaching shallow aquifers suitable for heat pump applications. The costs of deep wells and directionally drilled wells will be reduced by 10%.

- Wellbore Instrumentation - This work focuses on the development of probes which can give reliable information about the hydrothermal environment. State-of-art probes, including a radar fracture mapping tool, flow meter, and pressure sensor, will be fabricated. A unique downhole microprocessor with memory capability will be developed to avoid the need for expensive cable for data transmission. The expected effects of this research are:

  Decrease the cost of drilling production-related geothermal wells by about 5% through better identification of fractures.

  Decrease the uncertainties in measurements of downhole and wellhead temperature, pressure, and flow measurements for moderate temperature reservoirs by 25%.

  Decrease the uncertainties for similar measurements at reservoir temperatures greater than 250°C, by 50%.

Conversion Technology

To a large extent, this area focuses on improving the efficiency and cost-effectiveness of surface systems, including piping, turbine-generator, condenser, pumps, and so forth. The research activities concentrate on three areas in which the greatest improvements are expected:

- Heat Cycle - This work will yield improved conversion efficiencies for moderate-temperature (< 150°C) resources using binary-cycle technology. Better efficiencies will be obtained from the use of supersaturated vapor expansion, countercurrent integral condensation with recuperation, and the optimization of operating parameters and mixed working fluids. Modifications to reduce cooling water make-up requirements in arid areas will be pursued. The expected improvements are:

  Increase net hydrothermal fluid effectiveness of binary plants by 28%.

  Reduce cooling water make-up requirements for hydrothermal power plans by 20%.

- Materials - A serious deterrent to the expanded use of hydrothermal resources has been the lack of economic, durable construction materials for handling hot brines and other fluids associated with hydrothermal power generation. These fluids, with concentrations as high as one-third total dissolved solids, can be extremely corrosive; they also can deposit scale on exposed surfaces. Under such conditions, conventional materials deteriorate quickly. Resistant materials, such as stainless steel and titanium, are durable, but expensive. This research will continue finding low-cost alternatives in the form of new or reformulated elastomers, cements, and polymer-concrete linings for metals. The expected improvements are:

  Well cementing materials with a service lifetime of 30 years at high temperatures.

  A corrosion-resistant and low-fouling heat exchanger tube material costing no more than one-third the cost of high-alloy steels.

- Advanced Brine Chemistry - Hydrothermal fluids contain a myriad of chemical compounds, many of which can interfere with efficient plant operation or can create an environmental hazard. These fluids tend to be highly reactive, leading to corrosion and scaling of equipment surfaces. Treatments, such as inhibitors, can control many effects of hydrothermal fluids. This work will provide the basic chemical knowledge of fluid behavior in order to apply such treatments in a prudent, cost-effective manner. Efforts will continue to devise a system to detoxify hydrothermal wastes with biochemical processes. The expected improvements are:

  Reduce geothermal production well maintenance cost related to scale deposition by 20%.

Reduce geothermal field surface equipment costs related to scale deposition by 20%.

Reduce geothermal power plant maintenance and equipment replacement costs related to scale deposition by 20%.

Reduce cost of surface disposal of sludge from geothermal brines by 25%.

4.3 Accelerated Case Projections (1995-2005)

The accelerated case contains the base case, and its resultant technology improvements, plus advances brought about by new initiatives. Whereas the base case provides for gradual, systematic changes in technology that may take many years to have a widespread impact, the accelerated case offers quantum jumps in technology that could make more hydrothermal resources economic much sooner.

Five initiatives are proposed to augment the base case, which will result in the following improvements: (1) a synthesis of resource exploration methods directed toward locating and characterizing the nation's undiscovered hydrothermal resources which the USGS has estimated as high as 2000 quads; (2) an innovative drilling system (e.g., continuous coring; spallation) to reduce drilling costs by as much as 50% during the mid-term, making them comparable to oil & gas drilling costs; (3) a modular energy conversion system to hasten production from new fields with high or speculative risk; (4) an emplacement system and related equipment for geothermal heat pumps which should remove a major deterrent to wider application of this technology; (5) cooperative assistance to industry in competing on foreign and domestic energy markets.

The accelerated case yields only modest decreases in cost (10%) or an effective acceleration of roughly five years in market penetration during the mid-term. While these gains are significant for a technology that is already commercially proven, the real benefit of the case lies in the large resource base that is made available for production. The estimated potential generation capacity deemed likely to be developed increases from 25,000 MWe in the base case to about 45,000 MWe in the accelerated case. This improvement is the product of all the initiatives, but primarily the two directed at exploration and drilling. The full cumulative effects of the accelerated case are expected to be felt beyond 2005, after the improvements have permeated throughout the industry.

4.4 Long-Term Projection (>2005)

In an active evolving technology such as hydrothermal, improvements in cost and efficiency will continue to be made. The influences of innovations from related fields and new scientific insights into hydrothermal processes, along with an ongoing R&D effort, will ensure those improvements. Barring some unforeseen major breakthrough outside the bounds of the base program and initiatives, further improvements in

hydrothermal technology will be incremental, methodic, and gradual. However, they will have a major cumulative effect over 25 years. The long-term effects of the base case and accelerated cases relative to current technology is shown in Table 8. The total cost of energy is expected to be reduced from current levels by almost 60 percent.

Table 8. Expected Progression of Hydrothermal Electric Performance and Cost

	Technology Status Estimate					
Technical Parameter	Current		Mid-Term Target		Long-Term Target	
1. Producer Well Average Flow, 1000 lb/hr	396		473		562	
2. No. Wells Drilled in Construction Phase	26		20		14	
3. Base cost (No Risk) of well, $K	1,123		966		786	
4. Brine Effectiveness, Net Watthour/lb	7.8		8.2		9.5	
5. Flow into Plant, Million lb/hr	6.4		6.1		5.3	
6. System Design Capacity Factor, %	80		80		80	
Cost Account	CAP. $M	Cents /kWh	CAP. $M	Cents /kWh	CAP. $M	Cents /kWh
1. Identify Reservoir	6.1	0.13	4.7	0.10	0.8	0.01
2. Confirm Reservoir	17.6	0.41	8.4	0.19	4.0	0.08
3. Prod./Inject. Wells	41.3	1.79	28.4	1.27	12.5	0.47
4. Downhole Pumps	0.0	0.00	0.0	0.00	0.0	0.00
5. Gathering Equip.	8.1	0.36	6.1	0.23	4.1	0.13
6. Make-Up Wells	0.0	0.43	0.0	0.24	0.0	0.06
7. Power Plant (Core)	41.7	1.78	41.3	1.74	41.0	1.44
8. Brine TDS Effects	17.7	1.64	17.4	1.27	16.4	0.54
9. Gas Handling	4.5	0.23	4.3	0.21	2.7	0.10
10. Reservoir Insurance	5.7	0.18	4.9	0.15	3.8	0.10
Total Cost:	142.6	6.95	115.4	5.39	85.3	2.94

4.5 Beyond Hydrothermal

By definition, hydrothermal resources require the coincidence of heat as an energy source and water as a transport medium. This requirement places constraints on the quality, quantity, and distribution of hydrothermal resources. These constraints can be relaxed with the hot dry rock (HDR) resource which requires only an accessible heat source in fairly impermeable rock. At depth such conditions constitute the norm in the earth's crust, making HDR a ubiquitous resource.

HDR extraction technology requires the accurate placement of wells in a volume of hydraulically fractured rock. Water is circulated through the fractures using injection wells, becomes heated by the rock, and is produced via other wells. After energy extraction at the surface for power generation or direct use, the water is recirculated to the fractured-rock reservoir.

HDR technology and hydrothermal technology are similar and mutually supporting; improvements in hydrothermal technology have comparable application to HDR and vice versa. Any differences are ones of emphasis. For instance, HDR requires the use of well stimulation techniques, typically hydraulic fracturing, to create a reservoir; hydrothermal development usually does not require massive stimulation.

The strong similarities between the technologies suggest that initial application of HDR technology may be in or on the fringes of a hydrothermal field. In fact, HDR experiments have been proposed as a means of dealing with the reservoir problems at The Geysers.

While HDR technology has not yet been proven commercially feasible, experiments by Los Alamos National Laboratory in the late 1970's and early 1980's demonstrated the feasibility of the concept. A reservoir was created in hydraulically fractured rock at a depth of about 9000 feet, and water was circulated through the reservoir using two wells. The closed-loop system ran continuously for 286 days, at power levels of about 2.5 MWt (150°C) before the experiment was terminated. Since then, the British have operated a small HDR loop continuously for more than three years. Today HDR research programs are active in Germany, France, Japan, and the Soviet Union, as well as the U.S. and UK.

HDR is geothermal technology for the 21st century, after the potential of hydrothermal resources has been fully exploited. It is a logical successor to hydrothermal; its considerable potential should be assessed in planning the nation's long-term energy supplies.

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Section 4

TECHNOLOGY EVOLUTION RATIONALE FOR HYDROPOWER TECHNOLOGY

October 5, 1990

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TECHNOLOGY RATIONALE FOR HYDROPOWER ENERGY

Preface

This paper is intended to support the rationale for the hydropower projects contained in the National Energy Strategy. It is a supplement to the document *"Renewable Energy Technology Characterizations,"* March 20, 1990 (from Reference 2). The paper reviews the basic principles involved in the capture of hydropower energy and provides an assessment of the resource and the status of the technology, as well as an overview of its current market acceptance. The two scenarios utilized for projections are: 1) a base case in which the current trends in industry and technology development continue in a business-as-usual sense and 2) an accelerated research, development, and demonstration (R&D) case in which the pace and scope of federal programs is increased. Peer reviews and public hearings have indicated that the projects are reasonable.

1.0 INTRODUCTION

1.1 Technology Description

Hydropower plants capture the kinetic energy in flowing or falling water to generate electricity. The energy from the water is converted to mechanical energy and electrical energy by the use of a turbine and a generator. Turbines and generators are installed in or adjacent to dams, or utilize penstocks (pipelines) to carry the pressured water below the dam or diversion structure to the power house. Hydro projects are generally operated in one of three modes: run of river, peaking, or storage. The run-of-river project uses the natural flow of the river with very little alteration to the stream channel and little impoundment of the water. A peaking project uses an impoundment and releases water when the energy is needed. A storage project utilizes an extensive impoundment and stores water during the high-flow periods to augment the water available during the low-flow periods. This allows the flow releases and power production to be more constant. Many hydropower projects utilize a combination of operating modes. The power capacity of a hydropower plant is primarily the function of two main variables of the water resource: (1) flow rate expressed in cubic feet per second, and (2) hydraulic head, the elevation difference the water falls in passing through the plant.

The principal advantages of using hydropower are the large renewable domestic resource base, the lack of polluting emissions during operation, the capability to respond quickly to utility load demands in many cases, long plant lifetime, high plant availability, and very low operating costs. Disadvantages can include high initial capital cost and potential site-specific and cumulative environmental impacts. Potential environmental impacts of hydropower projects include altered flow regimes below storage reservoirs or within diverted stream reaches, water quality degradation, mortality of fish that pass through hydroelectric turbines, blockage of upstream fish migration, and flooding of terrestrial ecosystems by new impoundments. However, in many cases, proper design and operation of hydro projects can mitigate many of these adverse impacts. Hydroelectric projects also have beneficial effects, such as new reservoir-based recreation and the displacement of atmospheric emissions from fossil fuel-burning power plants.

Hydropower technology can be categorized into two types: conventional and pumped storage. Conventional hydropower plants utilize the available water energy from a river, stream, canal system, or reservoir to produce electrical energy. On multipurpose reservoirs and in run-of-river systems, hydropower production is just one of many competing purposes for which the water resources may be used. Competing water uses include irrigation, flood control, navigation, and municipal and industrial water supply. In the case of pumped storage plants, the water resource is pumped, usually through a reversible turbine, from a lower reservoir to an upper reservoir.

While pumped storage facilities are net energy consumers, they are valued by a utility because they can be rapidly brought on line to operate in a peak power production mode. The pumping to replenish the upper reservoir is performed during off-peak hours. This process benefits the utility by increasing the load factor and reducing the cycling of its base load units. In most cases, pumped storage plants run a full cycle every 24 hours.

Most conventional hydropower plans include six major components, as follows:

1. Dam - controls the flow of water and increases the elevation to create the head. The reservoir that is formed is, in effect, stored energy.

2. Penstock - a large pipe that carries water from the reservoir to the turbine in the power plant.

3. Turbine - turned by the force of water pushing against the blades.

4. Generator - connects to the turbine and rotates to produce the electrical energy.

5. Transformer - converts the generator's electricity to usable voltage levels.

6. Transmission lines - conduct electricity from the hydro plant to the electric distribution system.

The typical types of hydropower projects are illustrated on Figure 1 (from Reference 1).

1.2 Technology Applications/Uses

The major application for hydropower energy is in the bulk power market. The plants are owned by federal and state agencies, cities, metropolitan water districts, irrigation companies, and public and independent utilities. Individuals also own small plants at remote sites for supplying their own energy needs and for sale to utilities under the Public Utility Regulatory Policies Act (PURPA). Hydropower is an essential element in the national power grid because of its ability to respond to quickly varying loads; other base load plants such as coal and nuclear do not have this capability. Hydro plants can act as spinning reserve ready to take up large loads in seconds, which is not possible (or efficient) in plants with steam systems powered by combustion or nuclear processes.

Power Marketing Administrations in most parts of the country act as brokers for the transfer of large blocks of power throughout and in between regions of the country. Each region of the country is covered by a PMA with the exception of the northeast and north central states. The Northeast Power Pool is a private group of utilities which cooperate to serve some of the same purposes as a PMA. The PMAs negotiate power contracts with the various power suppliers and the utilities.

The hydro industry provides about 89,100 MW or 12% of the electric generating capacity in the United States. In addition to the production of about 223 billion kilowatt-hours of electricity of energy at hydropower plants, hydroelectric pumped storage plants are becoming very valuable as efficient load levelers to smooth out peaks in demand for all types of base load plants. This total hydroelectric power generation represented about 8.3% of the total U.S. electric utility industry generation in 1988. Throughout many regions of the United States, however, 1988 was a drought year and hydropower generation was well below average -- representing only two-thirds of the peak generation that occurred in 1983 when hydropower accounted for 14.4% of total U.S. generation.

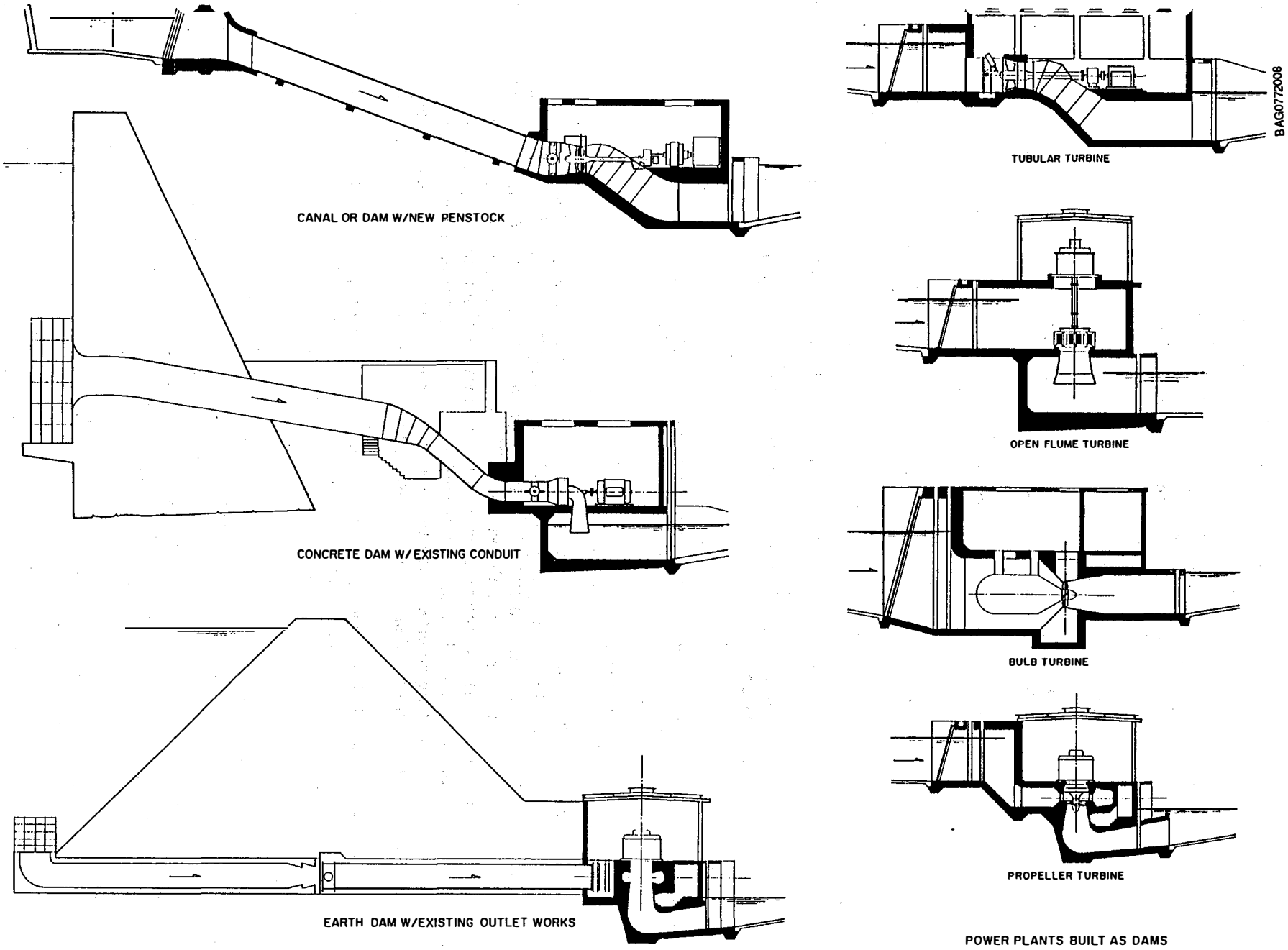

Figure 1. Typical Types of Projects

1.3 Resource/Land Use

The public hearings conducted as part of the National Energy Strategy produced testimony which concluded that the potential for development of hydropower was not well defined. The current Federal Energy Regulatory Commission (FERC) hydroelectric power resource assessment (HPRA) data base indicates that 74,100 MW of conventional hydropower capacity is undeveloped. Partial analyses of this data base by industry groups have indicated that the data include duplications and other errors that reduces confidence in the published estimates of hydropower developable potential. In response, a DOE team made up of representatives from each Power Marketing Administration, the Bureau of Reclamation, the Army Corps of Engineers, FERC, Idaho National Engineering Laboratory (INEL), and Oak Ridge National Laboratory (ORNL) has been established to reassess the hydropower resource that could be developed. The team drafted a preliminary assessment document in February 1990 indicating about 51,200 MW of undeveloped potential. Table 1 depicts the estimate from the preliminary results of the team report, updated to include current estimates for federal sites. A map showing the location of potential resources is given in Figure 2.

1.4 Industry Status

Hydropower development in the United States dates back more than a century. In the 1930's, hydropower provided 30% of the nation's total installed capacity and 40% of the electric energy generated. Since then, the growth in thermal-based capacity has surpassed the growth of hydropower to the point that hydropower (both conventional and pumped storage) represented approximately 12% of U.S. capacity in 1990. At the same time, growth of hydropower capacity has been slowing. Hydropower generating capability increased by 28 GW during the 1960's, by 17.9 GW during the 1970's, and by 8.2 GW in the 1980's. (Reference 3,4) Furthermore, more than 40% of hydropower capacity additions since 1972 have been pumped storage or hybrid conventional/pumped storage facilities, indicating that conventional hydropower additions have declined.

Before the year 2010, approximately 630 existing hydroelectric projects, representing 21.2 GW of capacity and 99,700 GWh of energy production, will be subject to FERC relicensing. (Reference 5.) Many of these older projects will require extensive modifications to comply with the new regulations. Relicensing data show that during the immediate pre-Electric Consumers Protection Act (ECPA) period of 1984-1986, no project was required to reduce generation during relicensing. In fact, 50% expanded their capacity and energy output.

In the immediate post-ECPA period of 1987-1989, over 70% of the projects relicensed showed a decrease in energy production. (Reference 3.) Consequently, without further R&D to resolve environmental and dam safety issues, more of these projects may be reduced in capacity, further reducing U.S. hydroelectric capacity.

The U.S. net generation based on May 1990 data is shown in Figure 3. (Reference 6.) Based on January 1990 data, the aggregate capacity of all existing hydroelectric facilities was approximately 89 GW. This includes 17 GW of pumped hydro capacity, 64 GW of conventional hydro, and 8 GW of small-scale (30 MW or less) hydro. The 1988 capacity of all facilities was 88 GW, which produced 223 billion kWh (Reference 4).

Hydroelectric power provides approximately 14.5% of the world's electrical energy, and hydropower plants operate in 86 countries with a total production capacity of approximately 2000 billion kWh in 1986 (conventional and pumped storage). Even with this contribution, less than 14% of the world's hydropower potential has been developed (Reference 7).

Table 1. Undeveloped Conventional Hydropower Potential National Perspective—All Regions (Preliminary Estimates)

	Existing Federal Sites	Existing Non-Federal Sites		New Dam Sites	Totals
	With Power and Without Power Plant	With Power Plant	Without Power Plant		
Number of Sites	---	117	2,363	1,864	---
Capacity - (MW)	4,980	1,525	13,707	32,693	52,905

NOTE: The estimates of undeveloped potential are not a projection of hydropower development that will be achieved in the future, because of the following factors:

- The impact of ECPA and the costs associated with ECPA are not known. The estimates do not reflect the effects of ECPA on current and future licensing decisions.
- Hydro development economics are site-specific, highly variable, and have not been considered in the estimate.

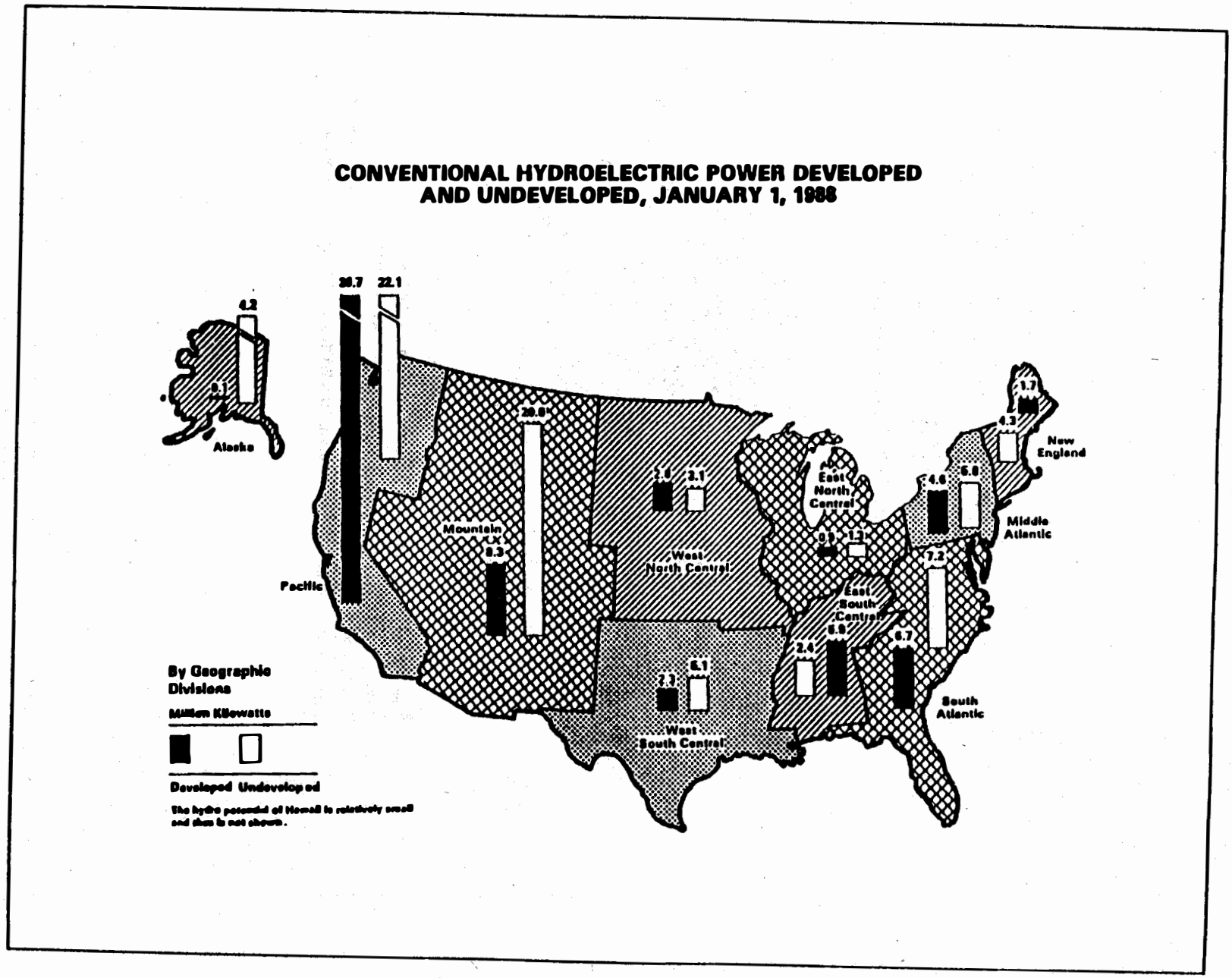

Figure 2. Map Showing the Location of Potential Resources

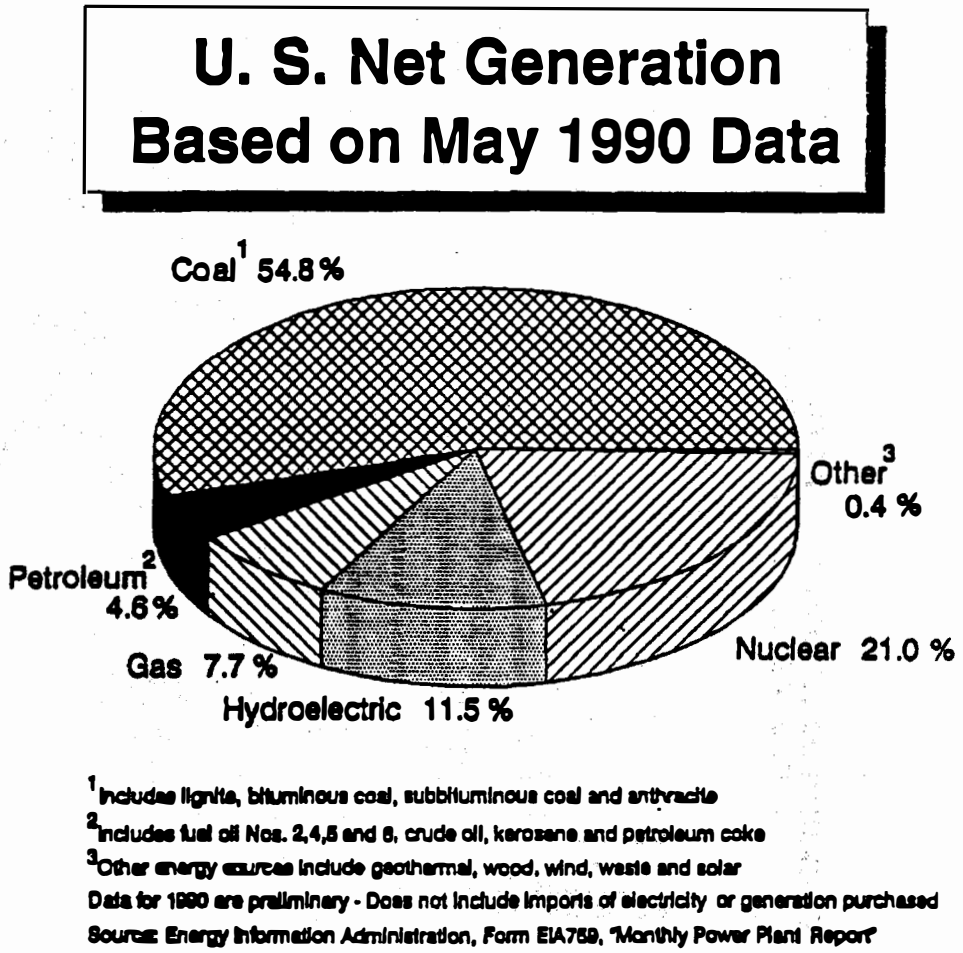

Figure 3. U.S. Net Generation Based on May 1990 Data

While the U.S. hydropower industry has declined, foreign interests have successfully filled the void. A recent Hydro Review Industry Directory listed 54 of 71 turbine suppliers with American addresses; however, the number of bona fide U.S. companies represented only a small portion of them. The last major U.S. manufacturer of hydraulic turbines was bought out by a German company a few years ago. In August 1989 the German firm announced its plans to merge with a Swiss company, further diluting U.S. participation in turbine manufacture. Many of the companies with a U.S. address are, in reality, sales organizations that deliver foreign-built equipment to projects in the United States.

It is estimated that between 40% and 50% of the $150 million to $250 million hydropower turbine business per year involves new equipment. Approximately 70% to 80% of this business goes to foreign suppliers. The situation is better for upgrading old turbines, probably for logistics reasons. It is estimated that about 80% of the upgrade work is done by U.S. companies.

1.5 Market Acceptance and Experience

The first hydroelectric plant in the United States was a water-wheel generator at Niagara Falls, which was used to illuminate the Falls by arc lamps in 1879. In 1882, the world's first hydroelectric central station, at Appleton, Wisconsin, provided electricity for incandescent lighting in homes and power for industry. By 1907, 15% of the electric generating capacity of the United States was provided by water power. Interconnection of power plants into a utility system accelerated the growth of hydroelectric installation through the 1930's. At the time, hydroelectric plants provided 30% of the nation's generating capacity and 40% of the electric energy actually produced.

As shown in Figure 4, the installed conventional hydroelectric capacity in the United States tripled between 1921 and 1940. This capacity can be classified as small hydropower, for it was largely developed for use in the textile industry and other industries on the rise during that era.

The capacity of conventional hydropower almost tripled again between 1940 and 1960, but this was due largely to federal development. At the same time, however, small hydropower (30 MW and less) actually decreased because of the retirement of more than 75% of the sites. The decrease was caused by several reasons: the relocation of small industry (textile mills) to the south; the development of larger hydroelectric plants; and the development of large, coal-fired electric plants during the 1960's.

Figure 5 illustrates the type of owner for the developed projects, representing about 2,100 sites. As can be seen, federal projects, private utilities, and municipals comprise the bulk of developed hydropower.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

The hydropower energy technology section of the *"Renewable Energy Technology Characterizations"* presents estimates of several figures of merit to characterize the cost and efficiency of the technology. Probably the most often cited figure of merit is the levelized cost to produce energy, in units of $/kWh. All figures of merit listed below are found in the hydropower energy technology characterizations.

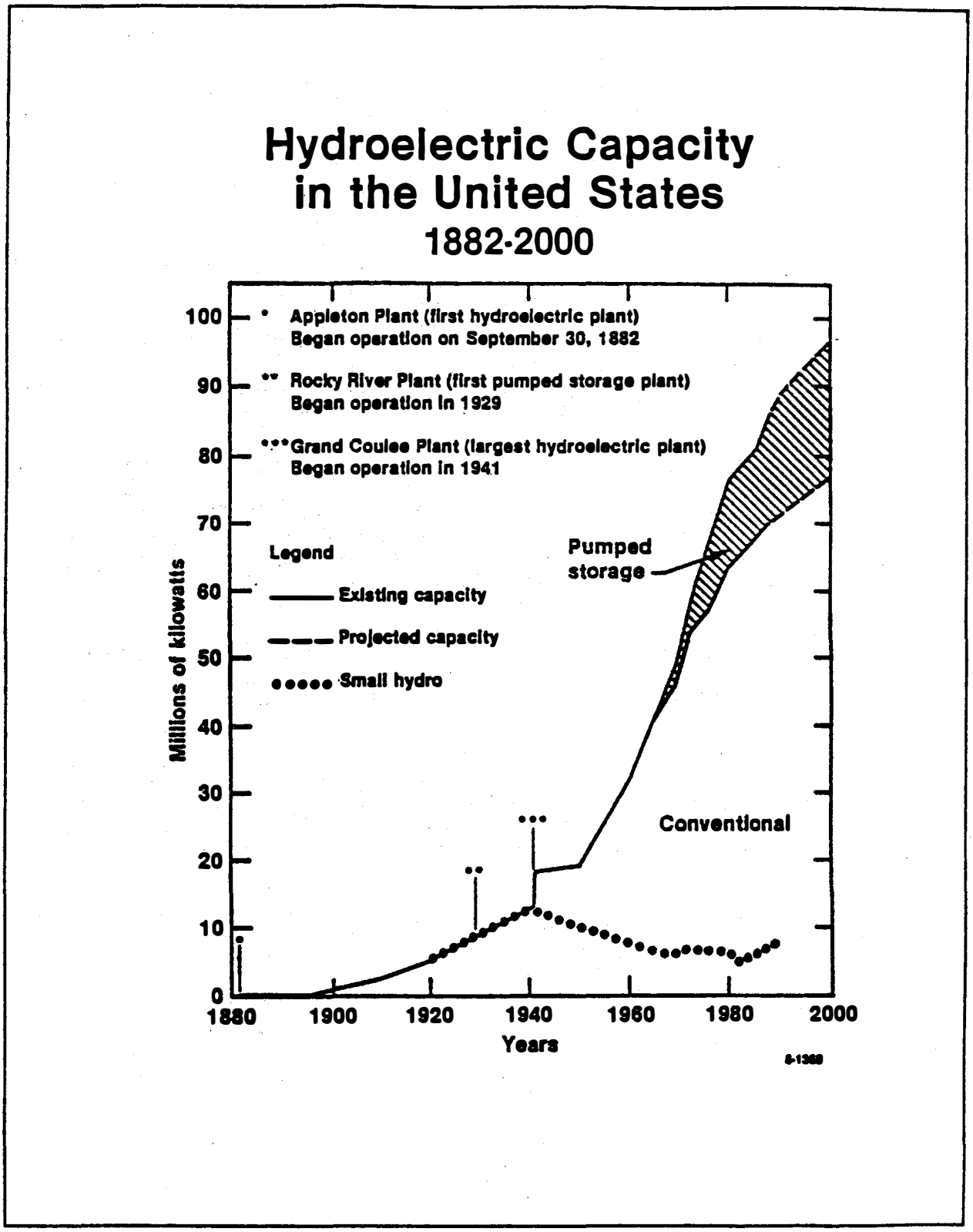

Figure 4. Hydroelectric Capacity in the United States 1882-2000

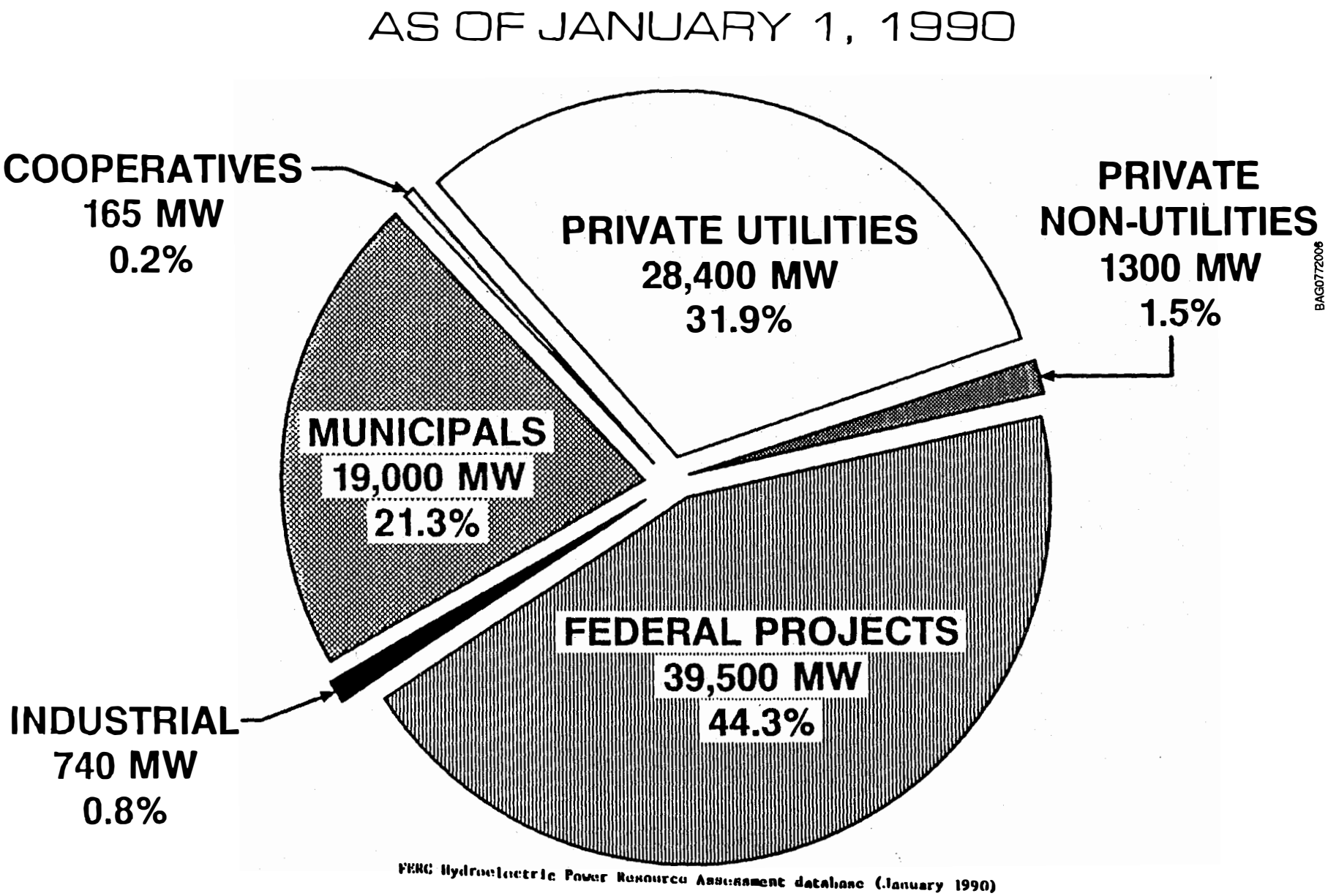

Figure 5. Developed Hydropower

Key Figures of Merit:

- Capital cost per unit of installed capacity ($/kW)

  Hydropower uses the cost per kW unit as a well known way to express cost. This figure of merit can be directly used to compare hydropower systems with other generation technologies. The costs per kW includes the licensing, design and engineering, construction, and other associated costs such as administration and interest changes during project development.

- Levelized cost per unit of energy ($/kWh) - The levelized cost per unit of energy combines the annual costs of energy production into a single figure. The costs include repayment of the total project investment with interest. The typical life-cycle cost for hydropower plants is 30 years; however, the license may be issued for 40 to 50 years which represents the average life of the project. The levelized costs are based on the finance period. Cost per unit of energy after the finance period is attributable solely to operation and maintenance (O&M).

- Capacity factor (%) - The capacity factor (usually referred to as plant factor for hydropower) is the amount of energy that the system produces as a percentage of the total amount that it would produce if it operated at rated capacity during the entire year. This figure can be used to calculate annual energy production using a method similar to that employed for other technologies

- System average efficiency (%) - The system average efficiency is the percentage of energy produced by the plant in ratio to the energy available in the water. This includes efficiencies of the turbine, generator, and all other equipment and facilities. It is sometimes called water-to-wire efficiency. It is a good technical measure for tracking performance trends.

- Operation and maintenance cost (cents/kWh) - O&M accounts for all costs incurred for regular, or scheduled, operation and maintenance of the hydropower plant facility. Costs include labor, material, parts, taxes, insurance, plant heating and lighting, and associated administrative costs.

2.2 Historical Technology Trends/Current Status

2.2.1 Historical Technology Trends

Hydropower has made a significant contribution to the national energy supply for over a century. As recently as 1930, hydropower provided 30% of the nation's installed capacity and 40% of the electric energy generated. The industry has steadily declined since then and in 1990 only about 12% of the nation's energy came from hydropower. Initially, the hydropower plants were small and were built for local consumption of the energy produced. Later, many of the old, small plants were retired in favor of new, more efficient large plants which energized large power grids that supplied power to loads far from the hydro plants. The low price of oil and coal then made fossil plants more competitive and they eventually became the main energy producers. Still, hydropower is competitive with conventional fossil capacity in base, intermediate, and peaking roles. New hydropower facilities requiring the construction of a dam typically have high front-end capital costs -- around $1700 per kilowatt -- which are offset by low operating costs ($0.002/kWh), long lifetimes (up to 50 years), and high plant availabilities. Estimated levelized capital and operating costs for new facilities vary significantly from site to site but are often competitive with conventional fossil generation.

Hydropower facilities are highly flexible. The output from facilities using single-purpose reservoirs can be varied to match electrical energy demands. These systems can also respond quickly to utility short-term load swings. Pumped storage facilities, though generally not considered a renewable resource because the primary fuel is usually coal or nuclear, have much of the operating flexibility of hydropower. This flexibility also provides a mechanism for accommodating intermittent energy production by using reservoir storage to ensure supply reliability and to smooth fluctuations in output.

In recent years, increasing competition for water resource use has made the construction of new hydro plants very difficult. On multipurpose reservoirs, hydropower production represents just one of several competing demands on the water resource. Others include irrigation, flood control, recreation, navigation, and municipal and industrial water supply. Run-of-river developments on rivers, streams, and canal systems use the in-stream water flow instead of impoundments to produce electric energy. The construction of new large (particularly high head) dams is now virtually blocked because of the environmental impacts at the few remaining undeveloped sites in the U.S..

Because large hydropower developments have decreased in recent years, U.S. manufacturers have abandoned the large turbine business. Foreign suppliers from Japan, Europe, and Canada are very competitive in the world market and have provided most of the new equipment needed for U.S. hydropower facilities.

The trend is now toward building lower head turbine units such as bulb or tube turbines because of the lesser environmental impact of run-of-river plants associated with this type of unit. Attempts are being made to reduce the cost and time of construction by various ingenious means. One example is the use of float-in power houses such as the one used at the new plant at Vidalia, Louisiana. This type of construction, where the power house was built at a nearby shipyard and floated to the site for installation, was projected to save $145 million and to reduce the construction time.

2.2.2 Current Status

Based on a 1986 Energy Information Administration (EIA) report, the average cost of five conventional hydropower projects that were placed on line between 1983 and 1986 was approximately $1700/kW (Reference 9). This EIA data also indicate that the annual operation and maintenance expenses for non-federal conventional hydropower plants in 1986 averaged 0.2 cents/kWh. These costs are competitive with other sources of electrical energy. Also, hydroelectric facilities are now highly efficient (85 to 90 percent), about twice that of fossil fueled plants.

According to the FERC January 1990 estimate, the undeveloped conventional hydropower potential is 74,100 MW. The DOE preliminary assessment document, dated February 29, 1990 (updated with new federal plant data), indicates approximately 52,905 MW of undeveloped conventional hydropower. The DOE estimate of 52,905 MW includes 20,212 MW at existing dam sites with and without power plants. The balance of 32,693 is considered new development. In addition, DOE estimates that 6,930 MW of additional capacity (non-federal - 2,230 MW; U.S. Corps of Engineers - 2,700 MW; Bureau of Reclamation - 2,000 MW) can be obtained by upgrading the efficiency at existing power plants.

Even with the large undeveloped potential, hydropower is not growing, and is in danger of declining. Specific issues cited in the NES hearings included the following:

1. Rapid changes in both federal and state regulatory policies negate or obfuscate developers' environmental studies, often while they are still in progress or after they have been completed.

2. Witnesses emphasized that the licensing process for a major facility requires 3 to 5 years or more, and, as a result, hydropower development is discouraged by increased project costs, greater uncertainty, longer lead times, and decreased profits.

3. In addition to discouraging new development, existing projects due for relicensing may be reduced in capacity or shut down.(Reference 3.) Through 2010, the licenses of approximately 630 projects with a total capacity of 21,200 MW will expire.(Reference 5.)

4. There has been little coordination among the various federal and state agencies establishing environmental and engineering requirements for development and operation of hydropower projects.

5. Environmental assessment methods are not sufficient for equitably comparing the costs and benefits achieved by mitigation requirements; no agency or organization is conducting the monitoring or research necessary to make progress in this area.

6. Due to the lack of research and consensus on instream flow, dissolved oxygen, and cumulative impact, there are no firm standards for evaluation.

7. There is a federal perception that hydropower is a mature technology, and therefore does not require federal R&D that could stimulate engineering improvements, efficiency improvements, and advanced technology and materials, both for new plants and for the retrofit/upgrade of existing plants.

3.0 COST/PERFORMANCE PROJECTIONS

Hydropower development is constrained by legal, institutional, and environmental issues. The primary objective of the DOE Hydropower Program is conduct the necessary research and development to mitigate the current constraining issues. Other research and development activities include those areas that will make available new resources such as ultra-low head sites and free-flowing rivers.

3.1 Base Case Funding Scenario

The base case funding scenario assumes that the FY 1991 annual funding level of $1.0 million remains constant over the planning period.

3.1.1 Base Case Technology Development Scenario

The FERC data base as of January 1, 1988, reported that the undeveloped hydropower capacity in the United States was 95.2 GW. This undeveloped capacity consisted of conventional (76.1 GW) and pumped storage (19.1 GW). An additional resource of 32 GW, excluded from development by the Wild and Scenic Rivers Act, was not included in this total. As stated earlier, the FERC estimate on January 1, 1990, was 74,100 MW of conventional and 17,300 MW of pumped storage potential. The Resource Assessment Team re-estimated the potential in February, 1990, to be about 52,905 MW for the undeveloped conventional hydropower potential. This new estimate included corrections for errors, duplications, and more recent restrictions that have been placed on development. Even with the recent reductions in potential and the growing environmentally restricted sites, there remains about one third of the total resource that could be, but has not yet been, developed.

This resource is not being developed because of the regulatory complexities and institutional and jurisdictional overlaps. The average hydropower licensing process for a major facility requires 3 to 5 years or more. As a result, hydropower development is discouraged by increased project costs, greater uncertainty, longer lead time, and decreased profits.

Based on low energy prices, surplus energy, regulatory and institutional constraints, and the termination of incentives in the former DOE Hydropower Program, it is estimated that a net increase of only 13 GW (8 GW conventional and 5 GW pumped storage) will be developed by the year 2030 (Reference 2). This reflects a growth of less than 0.5% per year. These extremely modest growth projections are also supported by a review of the industry forecasts for new hydropower construction for the year 2000. The loss of existing capacity due to the complex licensing procedures contributes to the low net growth.

3.1.2 Research Activities

In August 1990, DOE issued a draft report titled "Review of Impediments in Hydroelectric Licensing and Development in Support of the National Energy Strategy" (Reference 10). The purpose of this report was to: 1) identify regulatory and legislative impediments to non-federal hydroelectric resources; 2) analyze the impacts of these impediments on the development of additional hydroelectric resources; and 3) suggest actions to eliminate or alleviate the adverse effects of these impediments on hydroelectric development.

DOE is currently conducting two other studies: *Hydropower Resource Assessment Evaluation* -- an assessment of the potential for further development, and *Hydropower Mitigation Study* -- a critical review of environmental mitigation measures required in the development of hydropower and the associated costs. Future activities will be limited to monitoring and refining the issues and resource potential identified above. DOE will continue to work with industry to identify the most critical research issues.

3.2 Accelerated Hydropower R&D Funding Scenario

The accelerated hydropower R&D funding scenario assumes a total budget of approximately $30 million from FY 1992 through FY 1996.

3.2.1 Accelerated Technology Development Scenario

Additional hydroelectric power sources that were not considered as potentially developable resources are those projects that require additional R&D to further develop the equipment and technology. For example, the use of free-flow turbines in fast flowing rivers has been estimated to have a potential of approximately 12,500 MW (Reference 11). This concept is unique in that very little civil work is required and the plant can be installed without creating a water impoundment area or disrupting flow. Equipment has been developed, but the concept requires testing. Irrigation canals, domestic water systems, ultra-low-head (less than 10 ft) sites, and small-scale (less than 1 MW) sites may also provide additional resources. It is estimated that these projects could provide an additional 5,000 MW. R&D to develop new, inexpensive equipment is needed to make these sites feasible. Therefore, it is estimated that the baseline potential can be increased by 17.5 GW with an aggressive R&D program.

A federal R&D program to address environmental and dam safety issues and develop new equipment and technology would accelerate hydropower development. ECPA requires careful consideration of environmental, safety, and efficiency issues for both new development and the relicensing of hydropower facilities.

More recent analysis contained in the DOE report dated August 1990 (Reference 10) and other information indicates that an additional conventional capacity of 31,860 MW can be obtained by 2030. The DOE report also estimates a cost savings of $1.6 billion in the licensing process over the next 30 to 40 years.

3.2.2 Research Activities

The research activities to support expanded resource development and the reduction of legal, institutional, and environmental impediments include the following:

- Evaluate the environmental mitigation activities and associated costs to provide data to improve mitigation effectiveness.
- Improve performance that favors environmental aspects of operation (e.g., dissolved oxygen, fish passage).
- Develop economical turbines or other equipment that are less dangerous with fish.
- Develop dam safety technology to provide economical means for surveying and repairing existing dams that can be used in hydropower projects.
- Improve testing methodology for measuring flow rates and other parameters for testing turbines using full size or scale models. Develop the model for correlation procedures needed for prototype scale-up (e.g., tests involving air ingestion are not now considered to produce reliable results when scaled to prototype size).
- Develop environmental regulations designed to maintain or improve dissolved oxygen levels.
- Develop a methodology to improve the accuracy in determining in-stream flow needs.
- Improve designs that favor rehabilitating old plants.
- Develop turbine runners that entrain air yet maintain high efficiency in retrofitting old plants where reaeration is required.
- Improve the automated controls for hydropower plants to provide reliable, efficient operation; on-line diagnostics; environmental data collection; and report generation without requiring full-time operators.

The research activities to support engineering and efficiency improvements include the following:

- Develop kinetic energy turbines that use free-flowing stream potential (potential for new capacity is estimated at 12,500 MW).
- Develop ultra-low-head turbines that will capture energy at sites with development potential such as irrigation canals, diversion structures, etc. (estimated 5,000 MW potential).
- Develop cross-flow turbines that will improve efficiency by optimizing air injection and suction head in the draft tube (potential improvement in efficiency -- 5%).

- Design hydroturbines using new, innovative materials to increase durability (e.g., less susceptible to cavitation erosion and corrosion damage) and reduce cost (e.g., inexpensive runners that can be discarded instead of repaired).

- Develop standard flow passage designs for each range of plant parameters to provide low-cost, high efficiency plants.

- Improve the automated controls for hydropower plants to provide reliable, efficient operation; on-line diagnostics; environmental data collection; and report generation without requiring full-time operators.

4.0 RATIONALE FOR DEVELOPMENT IMPROVEMENTS

While the previous sections discussed issues underlying the decline of hydropower development, the undeveloped conventional hydropower potential and R&D opportunities, this section defines a general set of economic savings and capacity improvements believed possible, without specifying dates by which they will be realized.

4.1 Current Development (1990)

The 1990 development of hydropower is not representative of prior years. Because of increasing environmental, legal, and institutional impediments the development of hydropower has almost come to a halt. The large number of sites developed in the past gives evidence that the technology is considered extremely reliable.

4.2 Mid-Term/Long-Term Projections (1995 and beyond)

Estimates for mid and long-term projections and benefits are based on the developable resources and research areas discussed in the previous sections.

4.2.1 Regulatory and Legislative Improvements

R&D to establish technical and institutional bases focused on reducing the regulatory and legislative impediments to the licensing and development of non-federal hydroelectric resources.

The following results, with their projected cost savings and hydroelectric capacity benefits, were developed from the DOE analysis of regulatory impediments to the licensing and hydropower development process:

- Present FERC practice discourages licensees from proposing upgrading/efficiency improvements during the term of a license that do not affect existing project flow patterns or operations. Clarification of FERC regulations to allow improvements without requiring amendments that reopen licenses for complete reanalysis should encourage the rapid development of a projected 2,230 MW of hydropower capacity at low cost.

- Developing consistent technical resource evaluation methodologies for licensing could reduce licensing costs by 20%. Based on the projected number of projects to be licensed, this means a savings of $700 million (1989 dollars) in licensing costs that could be passed on to consumers over the next 30 to 40 years.

- Streamlining the licensing process to shorten licensing time from 5 years to 3 years and reduce uncertainty of licensing outcome would produce an estimated savings of $500 million (1989 dollars) in administrative costs that could be passed on to consumers. Reducing the licensing time will also encourage the development of 12,000 MW of new conventional hydro capacity in the next 30 to 40 years that would not be developed without such streamlining of the process. This added capacity would increase by more than one-third the conventional hydro capacity currently licensed by the FERC. This capacity could be licensed for an estimated savings of $200 million when compared to current practice.

- Legislative action to increase the time limit between the issuance of a license and the start of construction from the present 4-year maximum to 8-10 years should reduce the number of licenses that are surrendered or terminated. FERC records indicate that 1,750 MW of licensed capacity was not developed in the 1980's because changed economic conditions during the licensing process rendered the projects uneconomical. DOE estimates that another 750 MW of licensed capacity will not be developed in the next 5 years due to the low purchase price for electricity. If this 750 MW were developed, encouraged by extending the allowable time prior to construction start, DOE estimates that the $80 million (1989 dollars) already spent in obtaining licenses will not be in vain.

- Section 10(i) of the Federal Power Act (FPA) authorizes the FERC to waive most provisions of FPA Part I for projects of not more than 1.5 MW. Provisions that cannot be waived are: (1) the maximum 50 year license term; (2) charges for occupancy of Indian reservations; and (3) FPA section 10(j) relating to fish and wildlife conditions. Section 10(j) requires that license conditions for the protection of fish and wildlife resources should be based upon recommendations of Federal and state resource agencies. To streamline the process for small projects at existing dams, instead of doing an independent comprehensive review of the project, the FERC could, at the request of the applicant, simply adopt the fish and wildlife agencies' recommendations.

If all of the recommended actions were achieved (i.e., encouraging upgrading/efficiency amendments, developing consistent technical evaluation methodologies, reducing the licensing time by two years, extending the time allowed to begin construction under an original license, and exempting projects of 1.5 MW or smaller from many requirements of Part l of the FPA), then the savings from the improved licensing process could reach $1.6 billion. This includes $1.2 billion for the 30,000 MW (8,000 MW new and 22,000 MW relicenses) projected to be licensed over the next 30 to 40 years under current conditions and $360 million for the 15,180 MW of additional hydro power capacity encouraged by the changes.

4.2.2 Engineering and Efficiency Improvements

DOE estimates that additional hydropower resources can be obtained by developing new equipment such as:

- Kinetic energy turbines that use free-flowing stream potential (potential for new capacity is estimated at 12,500 MW). The practical development of this resource is estimated at 5,000 MW.

- Ultra-low-head turbines that will capture energy at sites with low-head development potential such as irrigation canals, diversion structures, etc. (estimated potential 5,000 MW). The practical development of this resource is estimated at 2,000 MW.

As a minimum, the engineering and efficiency improvements are estimated to provide an additional 7000 MW of capacity.

The U.S. Corps of Engineers estimates that 2,700 MW of capacity is available at their existing power plants by improving efficiency. In addition, 2,800 MW of new capacity is available by expanding some of the existing power plants.

The U.S. Bureau of Reclamation estimates 2,000 MW of capacity is available at their existing facilities through efficiency improvements. In addition, 2,180 MW is available by expanding the existing facilities.

The total estimated additional capacity available at U.S. COE and U.S. BOR facilities is 9,680 MW. Many of the research activities anticipated by DOE would directly support the development of existing federal facilities.

The efficiency improvement potential at non-federal facilities was discussed in Section 4.2.1.

4.3 Additional Capacity

The additional capacities are estimated based on an accelerated R&D. This intensified program would help assure that existing capacity remains on line and that new capacity is added by industry. In summary, approximately 31,860 MW (impediments - 15,180 MW; engineering - 7,000 MW; and federal facilities - 9,680 MW) of new capacity could be added by the year 2030.

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Section 5

TECHNOLOGY EVOLUTION RATIONALE FOR PHOTOVOLTAICS TECHNOLOGY

October 5, 1990

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PV TECHNOLOGY RATIONALE

1.0 INTRODUCTION

1.1 Technology Description

Photovoltaics is a relatively new electric power technology based on the direct conversion of sunlight into electricity using thin semiconductor layers. As long as it is exposed to sunlight, a photovoltaic (PV) device produces an electrical current that is proportional to the amount of light it receives. Because of PV's ability to directly convert sunlight to electricity, the environmental benefits of PV electricity production are significant. Electricity production, environmental benefits, and national energy security provide justification for the U.S. Department of Energy to support the development of PV technology.

The physical phenomenon upon which PV is based involves the separation of oppositely charged, light-generated carriers (electrons and holes) by a built-in electric field at the interface of the semiconductor layers. Today, the phenomenon is quite well understood and is a key element in modern electronics. This concept of a built-in electric field used in PV devices is also at the heart of most high-technology semiconductor devices, including diodes, transistors, and rectifiers. Knowledge about these similar devices provides a strong base upon which PV science is built.

The smallest unit of a photovoltaic system is the individual PV, or "solar," cell [cell is an appropriate term since PV devices produce direct current (dc) electricity like a battery cell]. Individual PV cells are connected together to form a PV module unit. Photovoltaic modules are the basic solar collectors for PV power systems. They are typically 0.1 square meters to several square meters in area and produce power in the range of 5 to several hundred watts under bright sunlight.

Photovoltaic modules are mounted on fixed or suntracking support structures and interconnected into photovoltaic arrays. The total area of modules used for an array or a field of arrays is determined by the overall PV system power level desired. To turn a PV array field into an effective electric power generating system also requires a power-conditioning and control system which acts as an interface between the dc power output from the array field and the type of electricity required for the specific application, often alternating current (ac) power.

A variety of semiconductor materials can be used for solar cells, and there are various ways in which the cells can be used in a photovoltaic module. The most common material used for photovoltaic cells is silicon, either crystalline, polycrystalline, or amorphous. But other advanced materials are copper indium diselenide, cadmium telluride, and gallium arsenide. The two major design approaches for PV modules are flat plates (planar arrays of PV cells interconnected into single collector modules) and concentrators (Fresnel lenses or reflectors that focus sunlight onto a much smaller area solar cell). The primary technological issue for photovoltaics is that of developing PV cells and modules that are both efficient and low cost, because the PV module costs tend to dominate the overall PV power system cost. The motivation for developing photovoltaic concentrator modules is to offset PV cell costs with the lower cost of concentrating lenses or reflectors. The variety of materials and module design approaches raises the probability of attaining low cost. Attaining those costs will be based on a generic capability of photovoltaics, not on some unique property of one PV technological path.

The simplicity of the photovoltaic mechanism, directly converting solar energy to electricity in a solid-state device, also implies that it has unique characteristics. In particular, PV power is environmentally benign, producing no air or surface pollutants or noise, consuming no fuels, and requiring no cooling water. On the other hand, the manufacture of PV cells requires many of the same precautions used by the high technology semiconductor industry. PV's operational characteristics make photovoltaics very attractive at a time when we are concerned with energy security, air pollution, and the possibility of global warming. Moreover, the solid-state nature of PV implies that with proper module designs and engineering, PV power systems should have very low operation and maintenance (O&M) requirements as well as excellent lifetimes. Low O&M costs are a salient economic characteristic of the PV power systems that have been deployed during the past decade. In some cases, major PV fields have been run by computer without on-site personnel.

1.2 Applications, Users, and Market Acceptance

Photovoltaic systems have been in use for approximately 30 years as spacecraft power units. Indeed, the reliable performance of PV cells in space represents the first major accomplishment of this technology and, also, provided the impetus for essentially all of the development of PV technology before 1970. Photovoltaic power systems are still extensively used for space power applications, and represent close to a $100 million per year industry worldwide.

Terrestrial applications of PV technology have also grown steadily over the past 15 years and have sharply accelerated in the last two years. The current range of applications is very broad because of PV's modularity. Indeed, PV is a practical electrical power technology for applications ranging from the milliwatt levels required in solar calculators to megawatt power levels needed by electric utilities. In addition, the capability of PV systems to operate without continuous operator attention and without fuels make the technology ideal for remote power needs, such as communication systems located on mountain tops, water pumping systems, remote monitoring or refrigeration systems, and any other electric power application which is not readily serviced by an electric utility grid.

The overall market for PV technology includes three major segments: consumer products, remote power supply, and bulk power generation. The consumer product market is characterized by millions of small, milliwatt-sized systems used for powering products such as calculators and watches. It is also expanding into somewhat larger systems, such as walkway lighting and house address lighting systems. This market is approximately 10 megawatts per year, worldwide, and growing steadily.

By far, the largest market for PV today is in the remote power supply area. This market encompasses a very broad range of applications including communications, highway lighting and call boxes, navigation aids, security systems, water-pumping systems, cathodic protection, vaccine refrigeration, remote monitoring, rural housing, and small village power systems. Although this market segment is called remote, it in fact includes applications which are sometimes adjacent to existing utility power service. For example, remote market applications such as bus shelter lighting are often more economically served by a standalone PV power system than by the installation of a transformer and a drop line from an existing service line overhead. The current world market in this remote power segment requires approximately 40 megawatts per year and appears to be expanding rapidly. It is largely the remote power market which has caused the dramatic accelerations in PV sales in the past two years.

The third market segment is bulk power generation, and represents applications for PV technology which are electric power grid connected. These include PV power systems on

users' sites, such as PV power systems on grid-connected residences, or they may be PV power generation sources which provide electricity to the utility busbar from some centralized location. Today, markets for PV power in this sector are largely experimental or prototypical in nature. PV technology is generally not cost effective in this market segment, so the bulk power systems which are being built are motivated by both the electric energy produced and the PV technology experience gained.

One of the most interesting aspects of PV technology markets at the present time is the rapid change from a demand-limited to a supply-limited industry in just the past two years. This rapid change was caused by the growing recognition that PV technology is the best source for a wide range of power applications not readily served by electric utility grids. It is important to note that many of these applications sectors are just beginning to be served by photovoltaics. For example, there are hundreds of millions of residences in the world without electricity today; yet there are only a few thousand PV-powered residences. As another example, the U.S. Forest Service has thousands of applications for electricity throughout its numerous facilities. They have just begun to use PV power systems in a wide variety of their applications. Thus, while U.S. sales of PV modules have increased about 25 percent per year for the last two years (Figure 1), product demand has increased almost 50 percent per year and that demand is likely to continue to grow very rapidly. We are likely to continue to see a supply-limited PV industry worldwide for five more years. A corollary is that, while industry will be lowering manufacturing costs during this period, they may not have the motivation to lower prices in this high-demand business environment.

1.3 Resource Base

The resource base for PV can be defined in terms of several resource requirements: sunlight, land area, and materials for systems. Of these, the most critical is sunlight, since it provides the 'fuel' from which PV electricity is produced. Land and sunlight issues are intimately connected, since the total available resource is the product of the density of sunlight and the land (or roofspace) available for PV.

Of course, sunlight is unavailable at night and is intermittent and to some extent unpredictable during the day. But study of the relationship between PV and the solar resource has shown that workable system solutions can be incorporated to ameliorate these problems. The most important facts about the solar resource in terms of PV are the following:

- Seasonal sunlight variations are relatively predictable
- The solar resource base is huge in relation to the potential demand
- PV is not geographically limited in the U.S. by a lack of sunlight
- PV output has added value because it is well-matched to summertime peak demand for electricity in many U.S. locales

A similar set of important observations can be made concerning the land/solar resource:

- Land requirements for PV are reasonable and affordable
- PV siting is very flexible: sites include waste or waterless land, as well as rooftops or structures atop parking lots, etc.

Scientists have spent more than a decade studying the availability and amount of sunlight throughout the U.S. They have measured actual sunlight totals (i.e., including cloud cover, rain, etc.), breaking these down by location, date and time, and type of sunlight. By doing so, they have provided us with a series of maps (see Figures 2-4) that detail an average annual amount of available sunlight. Similar maps are available by month as well. In addition, the

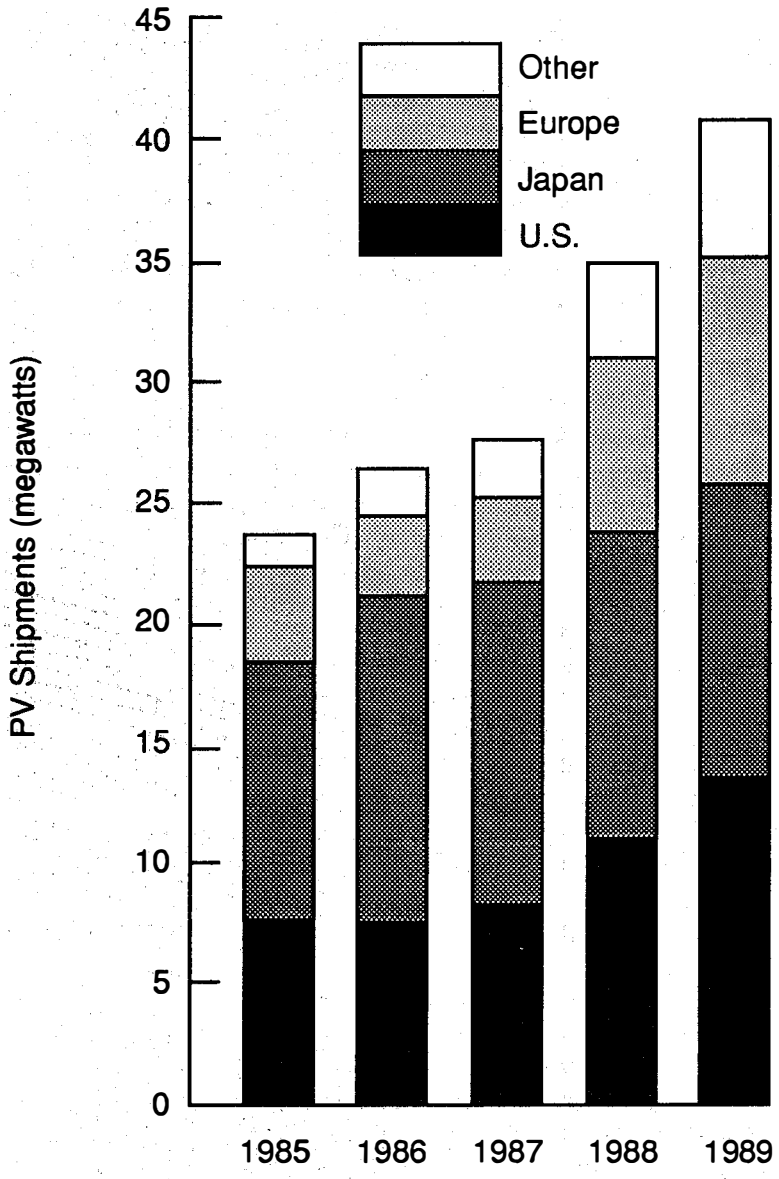

Figure 1. Photovoltaics World Market Share

maps and data bases that go with them have allowed scientists to develop models of solar availability that can be used to actually predict the amount of sunlight at various locations. The maps, local measurements, and models, allow us to know a great deal about the total solar resource; and they allow engineers to design their PV systems to meet specific needs.

The maps of Figures 2-4 show three different kinds of sunlight because they reflect differences implicit in three types of PV systems. Figure 2 shows how much sunlight would be available to an array of flat-plate PV modules mounted on a fixed (nontracking) support structure. This is the cheapest support structure for PV, so in many cases it is economical despite losses from not tracking the sun. [The units in Figures 2 and 4, megajoules/m^2-day, are almost equal to a hundredth of total annual energy in kilowatt-hours, i.e., 1 MJ/m^2-day is about the same as 100 kWh/m^2-year. So an average U.S. location such as Kansas City, MO, gets about 18 MJ/m^2-day, which is equivalent to about 1800 kWh/m^2-yr. This latter is a more accessible unit in terms of our experience with electricity. A typical US home uses from 5000-10,000 kWh per year, depending on whether it is air-conditioned.]

Figure 3 is an approximation of the amount of sunlight available to flat-plate PV modules when they are mounted on a tracking system that follows the sun all day. This means that the sunlight is always directly normal to the PV modules; it is the largest amount of available sunlight. The map is an approximation since national map products similar to Figure 2 have not been produced for two-axis tracking flat plates. Units are in MWh/m^2-year (1000 kWh/m^2-yr). The amounts shown on this map are about 30% higher than those in Figure 2, due to enhancements realized from tracking the sun. The final map (Figure 4) shows another kind of sunlight, called direct sunlight, which is the sunlight directly from the sun's disk. Figure 5 can be used to define this 'direct' sunlight. It is the sunlight that has not been redirected by intermediate cloud or atmospheric scattering. Even on a clear day in the desert, the direct sunlight is only 80% of the total sunlight (the rest is light we see as blue sky, clouds, and ground reflections). Figure 5 shows something else: at noon at the Earth's surface, we receive about 1000 watts/m^2 of solar power. The sunlight of Figure 4 is that which is available to PV systems based on concentrating sunlight. It is more similar to the resource availability of another solar technology, solar thermal concentrators. The indirect portion of the sunlight is unusable because it is nondirectional and unfocusable. In comparison to the sunlight available to fully tracking flat plates, it is about 30% less even in the sunniest locations. In cloudier locations like the East Coast, it can be over 50% less because so much direct sunlight is cut out by the clouds. These kind of variations in solar resource have a substantial impact on which kind of PV module/tracker one chooses for a specific application.

We can use these maps to draw some important conclusions about sunlight and PV. We can estimate the amount of sunlight available within the U.S. as the product of U.S. land area and the average sunlight within the U.S. We will use a conservative value of 1800 kWh/m^2-yr from Figure 2 (nontracking flat-plate). The U.S. uses about 2.5 x 10^{12} kWh/yr of electricity, and the total sunlight available is much larger, about 2 x 10^{16} kWh/yr.

A second conclusion *that is almost as important* is that geographical variations in US sunlight are within very acceptable limits. For instance, using Figure 2, we see that "bad" areas such as the Northeast get almost 80% of the sunlight that average locations get. One of the best PV options, flat plates, does not require a desert location to be practical. To be quantitative, sunlight in the continental U.S. varies by only a factor of two. So if PV electricity costs 5 cents/kWh in a sunny place like Phoenix, it will (at worst) only cost 10 cents/kWh in an extremely cloudy place like Seattle, and those are the extremes. Conventional energy prices already vary by a greater amount (three to one) across the US due to local variations in generation techniques--use of oil, coal, nuclear, or hydro. *The ubiquity with which PV will eventually be applicable is a unique strength.*

AVERAGE DAILY GLOBAL SOLAR RADIATION ON A SOUTH FACING SURFACE, TILT = LATITUDE (MJ/m²)

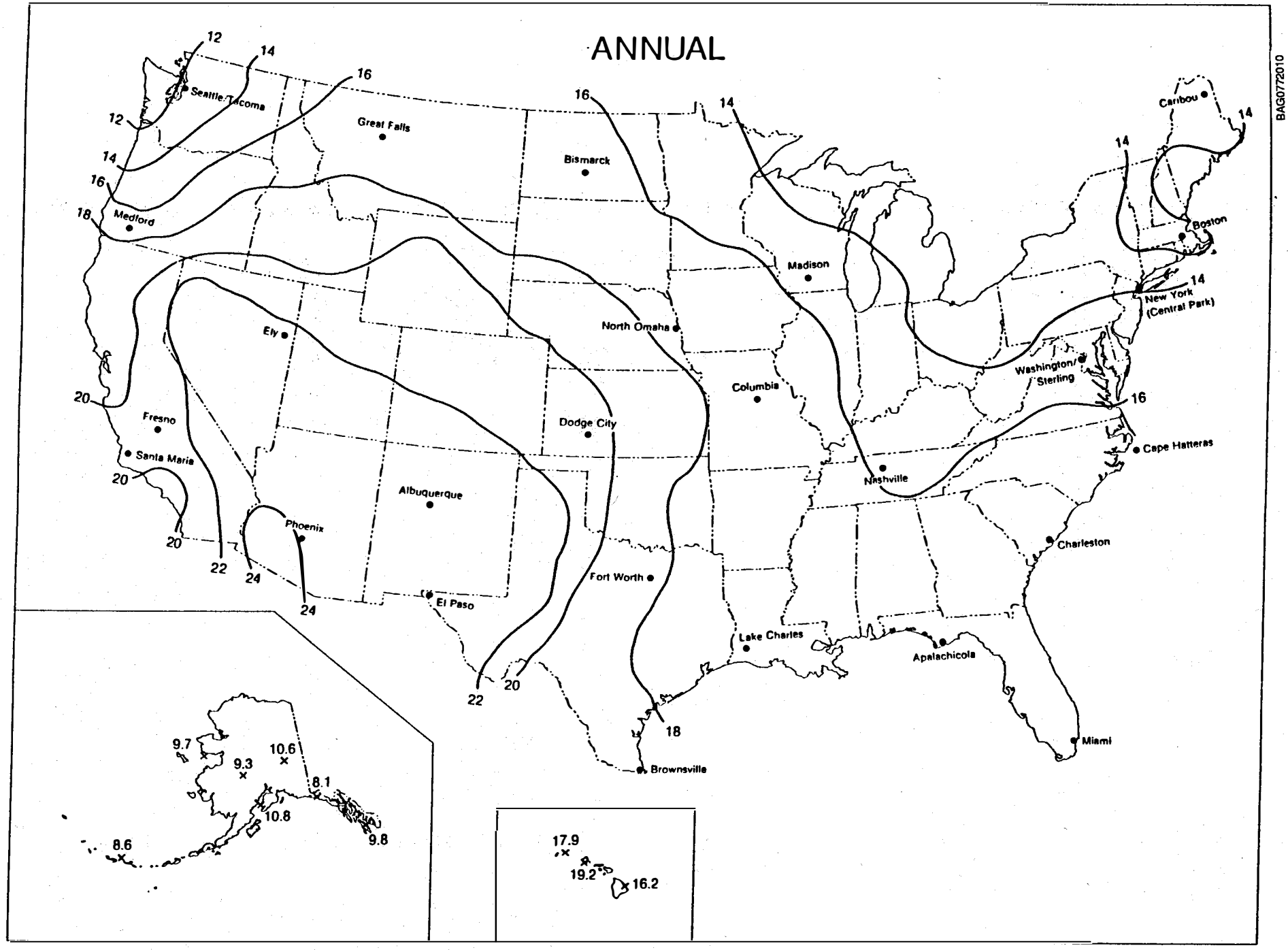

Figure 2. Flat Plate, Non-tracking System

How Much Energy Does the Sun Provide?

Average Annual Solar Radiation

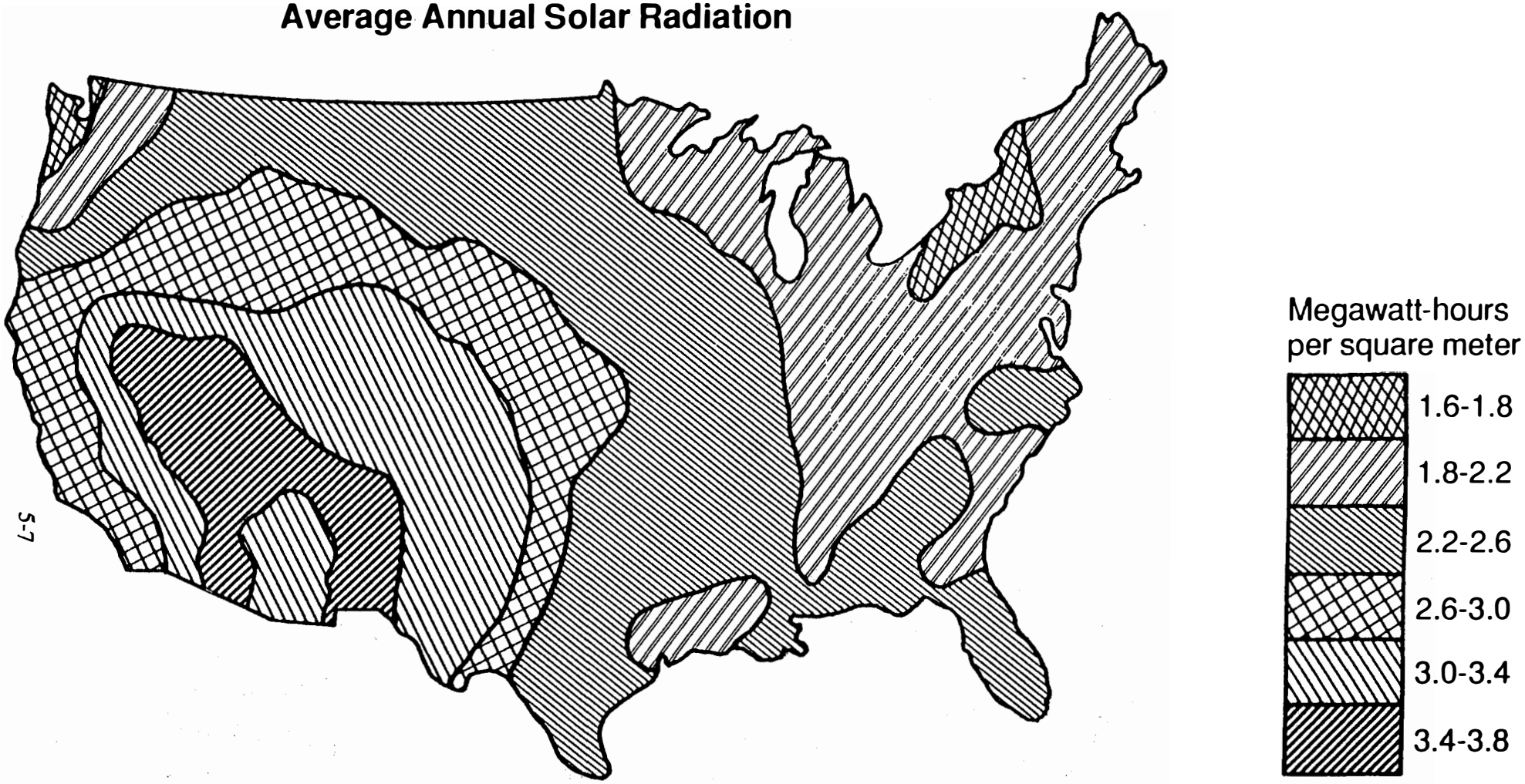

Figure 3. Total Sunlight for a Two-Axis, Flat-Plate System

BA-G0496508

AVERAGE DAILY DIRECT NORMAL SOLAR RADIATION (MJ/m²)

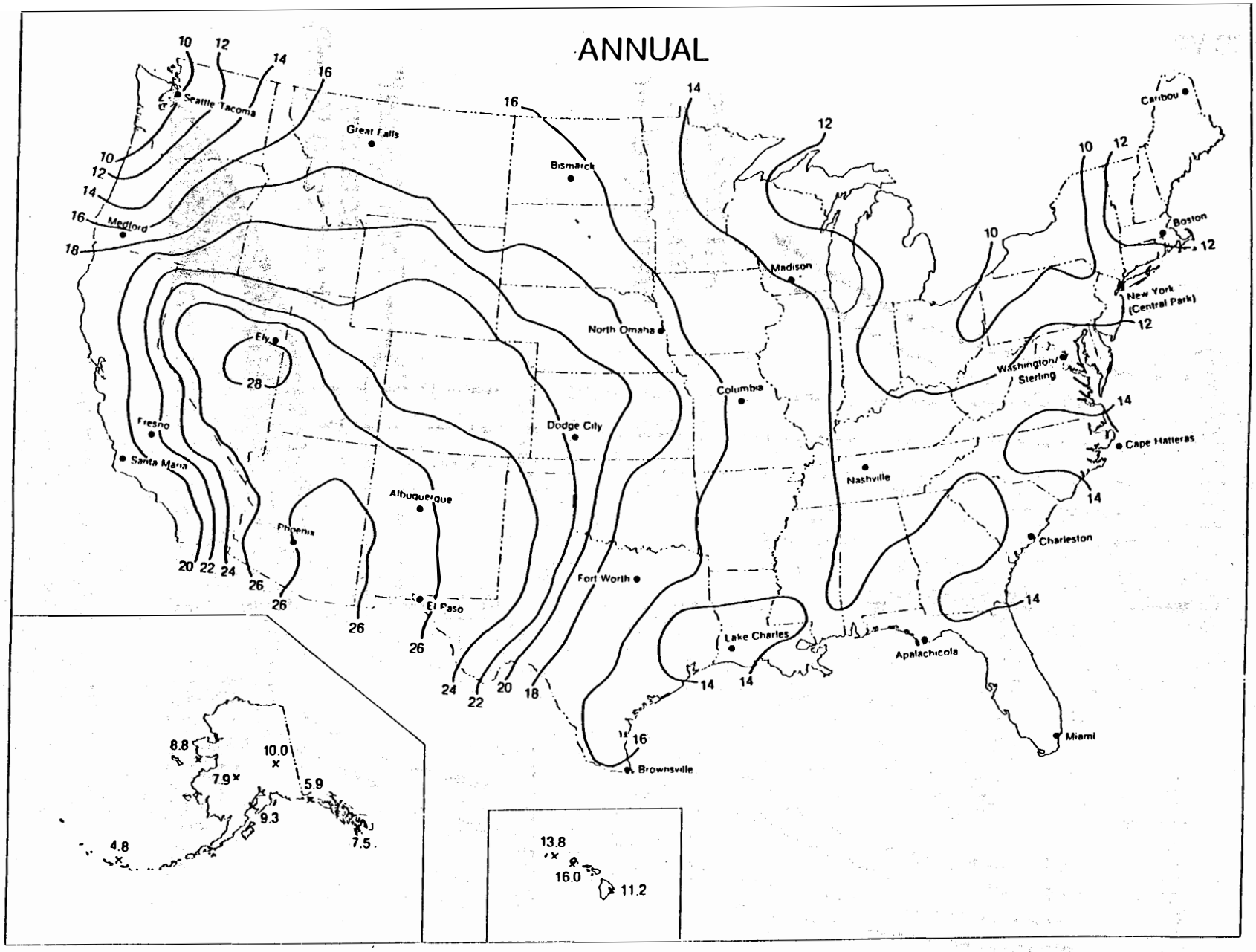

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Figure 4. Direct Sunlight Available to a Concentrator System Has the Most National Variation.

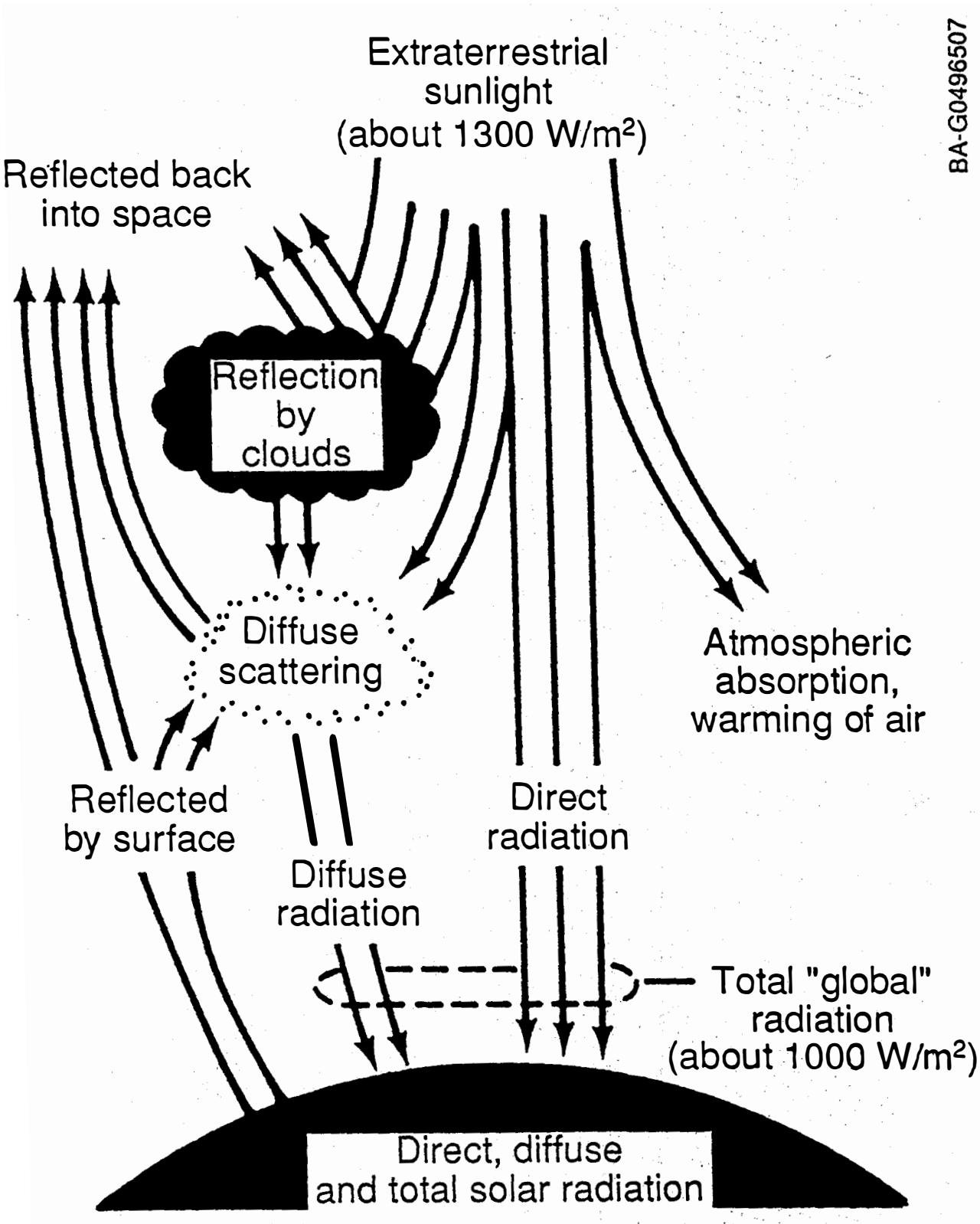

Figure 5. Losses in the Atmosphere

Figure 6 shows another important aspect of PV and sunlight. It shows the average demand for electricity in California during the summer. This demand is dominated by air-conditioning loads that rise with temperature. Under the load curve is the curve of a PV system's output, showing that it fills in the shape of the utility demand curve. In fact, studies have shown that PV provides very valuable electricity, since much of its output coincides with a time when the utility is supplying peak power--its most expensive product. "Peak shaving" (the supply by PV of afternoon electricity that shaves a utility's need to provide it by conventional means) is expected to be one of the earliest multi-gigawatt markets for PV.

The solar resource and land requirements for PV are intimately connected. The sunlight-to-electricity conversion efficiencies of various PV technologies vary substantially--typical flat-plate modules are about 10%-14% efficient today. Similarly, PV modules cannot be perfectly packed together when they are made into arrays. Space must be left between tilted arrays to avoid shading and to allow for maintenance access. We can define a packing factor as the ratio of module area to total land area. A reasonable packing factor is about 40%. For this analysis, we will assume that our modules (circa 2000 AD) will be about 15% efficient and the array will have a 40% packing factor. In addition, we will de-rate our assumed system output by 20% in order to account for various small losses (dirt on the modules, resistance losses in transmission, temperature-driven module losses...). So our PV system efficiency will be about 12% (15% x 0.8). But with a 40% packing factor, we will get only 4.8% efficiency in terms of the amount of exposed land surface. This means that in an average, Kansas City-like location, we will get a little over 80 kWh/m^2 (1800 kWh/m^2 x 0.048) of output for each square meter of land area. This would be about 200 million kWh/year from a square mile of land area. To provide 10% of the U.S. with PV electricity would require setting aside 0.03% of U.S. land area (1250 square miles).

Put in perspective, such land requirements are relatively small. A recent study at Meridian Corporation (Meridian Corp., Energy System Emissions and Materiel Requirements, prepared for the U.S. DOE Office of Renewable Energy, February 1989) concluded that area needs for PV are of the same order as those that we already incur for electricity generated by coal. Missing in our usual analysis of coal is the land for exploration, mining, processing, and disposal. Including all these makes coal and PV land use quite comparable. Other comparisons are also favorable: A Canadian utility, Quebec Hydro, has almost 10,000 square miles of reservoirs to supply its dams. The U.S. military uses over 30,000 square miles within the U.S. for its purposes. Of existing farmland, almost 230,000 square miles are in set-aside programs. Thus the idea of using 1000 to 10,000 square miles of the U.S. to supply from 10% to 100% of our electricity does not compare badly with other, existing land uses. In fact, PV's relatively good efficiency in converting sunlight into electricity is one of its strengths in terms of a possible very large future role, i.e., one that would include intermediate and baseload electricity (with storage) and even transportation components (electric or hydrogen vehicles). PV should be able to meet such needs without changing our accepted patterns of land use.

Another way to put land use into perspective is to understand its small impact on PV costs. Highest quality farmland in Illinois is priced at about $2000/acre. But on the same acre (about 4000 m^2), we can place about 1600 m^2 of modules. Our cost projection for PV modules is about $50/m^2, so the value of the modules on an acre would be about $80,000. Land costs ($2000) are only 2.5% of the module costs (which are themselves only about half of the PV system cost). Land is such an unimportant part of PV system cost that free land would make little difference in whether a PV system were cost-effective or not. (Obviously, current costs of PV modules, which are higher, would even more heavily de-emphasize land costs.) Except for unique cities (where roofspace can be used) and high-cost places like Hawaii, land in the

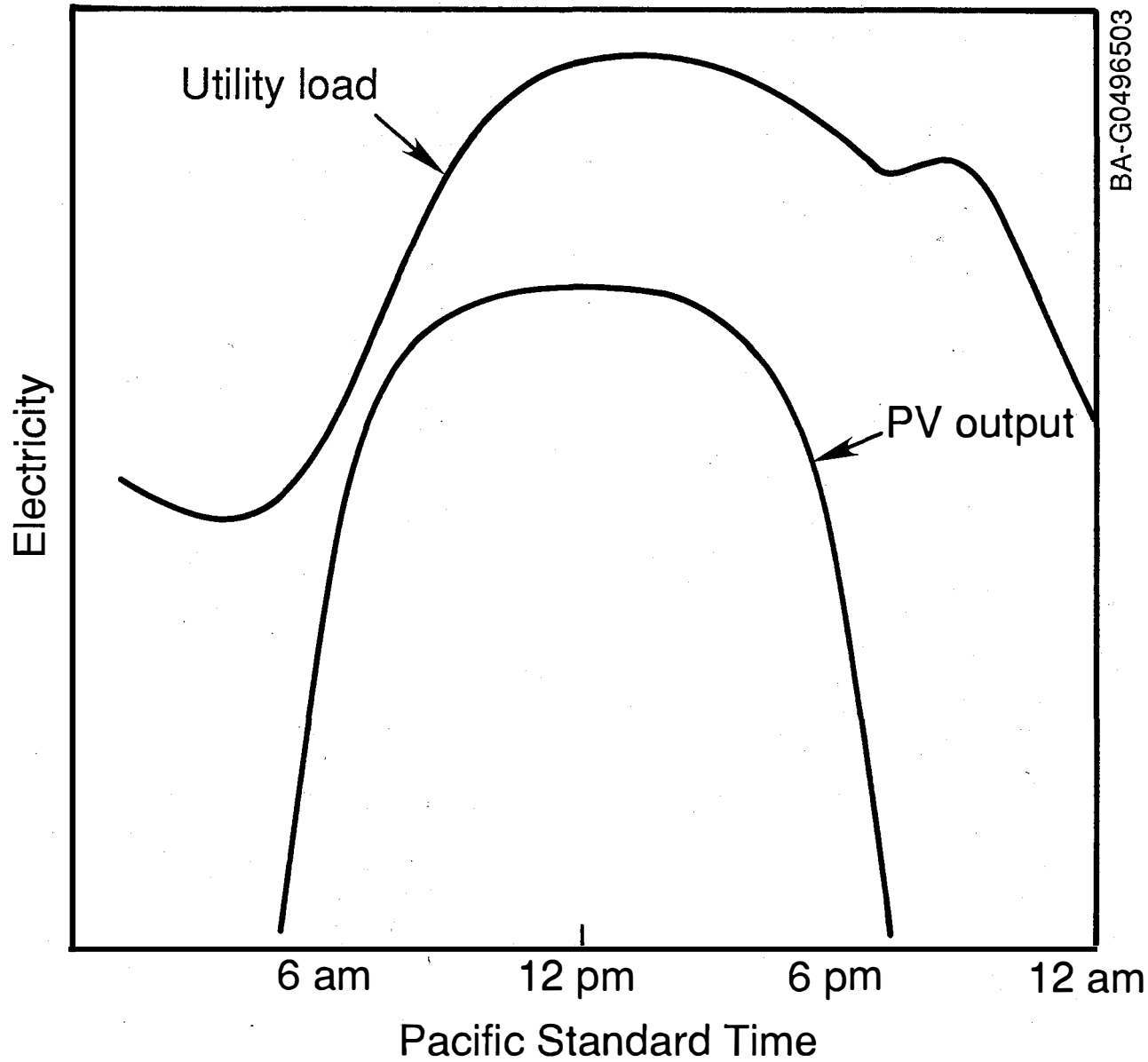

Figure 6. The Value Of PV Electricity Is Enhanced Because It Is a Close Match to the Summer Air-conditioning Peak of Many Utilities

U.S. is available at prices that mean that PV systems are usually not going to be limited by the cost or size of land needs.

Finally, issues of land size and siting can be ameliorated even further by two other factors: PV needs no water, so it can be located on otherwise low-use land like deserts; and PV can be dispersed and put atop roofs, parking lots, and rights-of-way. Consider the worst-case example for PV land needs: the populous Northeast. Because of PV's flexible siting, it should be possible to install PV on residential and commercial rooftops as well as atop parking facilities. In fact, it may be easier to sight PV in the Northeast than it would be to site conventional fossil or nuclear because of NIMBY (Not In My BackYard) issues associated with the latter.

Materials resources needed for PV are often overlooked in these analyses because they are so small. The bulk of materials for large utility systems are concrete and steel. The primary materials for PV modules are glass and the semiconductor material ("Recent Developments in Photovoltaics," *17th IEEE Photovoltaic Specialists Conference*, J. Stone, E. Witt, R. McConnell, T. Flaim, T. Surek, and D. Ritchie, p. 1178, 1984). Thin film modules (amorphous silicon, copper indium diselenide, cadmium telluride, and gallium arsenide) typically require only about 10 grams per square meter because they absorb sunlight much more strongly than crystalline or polycrystalline silicon. These latter materials use 500 to 1000 grams per square meter, as thicker layers are needed to effectively absorb the sunlight. In terms of the world's available resources, all of these materials are sufficiently abundant for widespread PV use.

2.0 Technical Status

2.1 Figures of Merit

The economics of PV are largely determined by the cost of the key PV component, the module. The history of PV can be drawn from the status of PV module technology--i.e., the status of module cost, efficiency, and outdoor durability. Figure 7 shows how well the cost of PV systems have tracked the cost of PV modules. In this case, the modules are crystalline silicon, the mainstay of PV since the beginning. In the 1990s, crystalline silicon will be supplemented by a series of competing PV options, including thin films, concentrators, and advanced high-efficiency options.

Figure 7 gives a good insight into the progress of PV: PV electricity cost has dropped because module efficiency has risen and manufacturing costs have fallen. But despite the fact that module costs still dominate PV system costs, cost for the rest of the PV system (supports, power-conditioning, etc.) will become more important as module costs fall. We will return to so-called 'balance-of-system' (BOS) costs below when we address the ultimate low-cost potential of PV.

The cost of electricity produced by a PV module is driven by manufacturing cost and module efficiency. *Efficiency alone* is not enough to characterize the value of a module. For example, one could have a module that is twice as efficient as another but that costs a hundred times more to make. The output electricity of the expensive module would be about 50 times more expensive than the output of the less-efficient module. Achieving the best combination of high module efficiency and low module cost is the focus of PV R&D.

Another factor, module stability, is also essential. Crystalline silicon modules are intrinsically stable, which means that they could operate indefinitely if they were not damaged by external influences. But even PV devices that are intrinsically stable must be encapsulated from the environment; humidity, rain, dust, and pollutants must not be allowed to enter and affect the

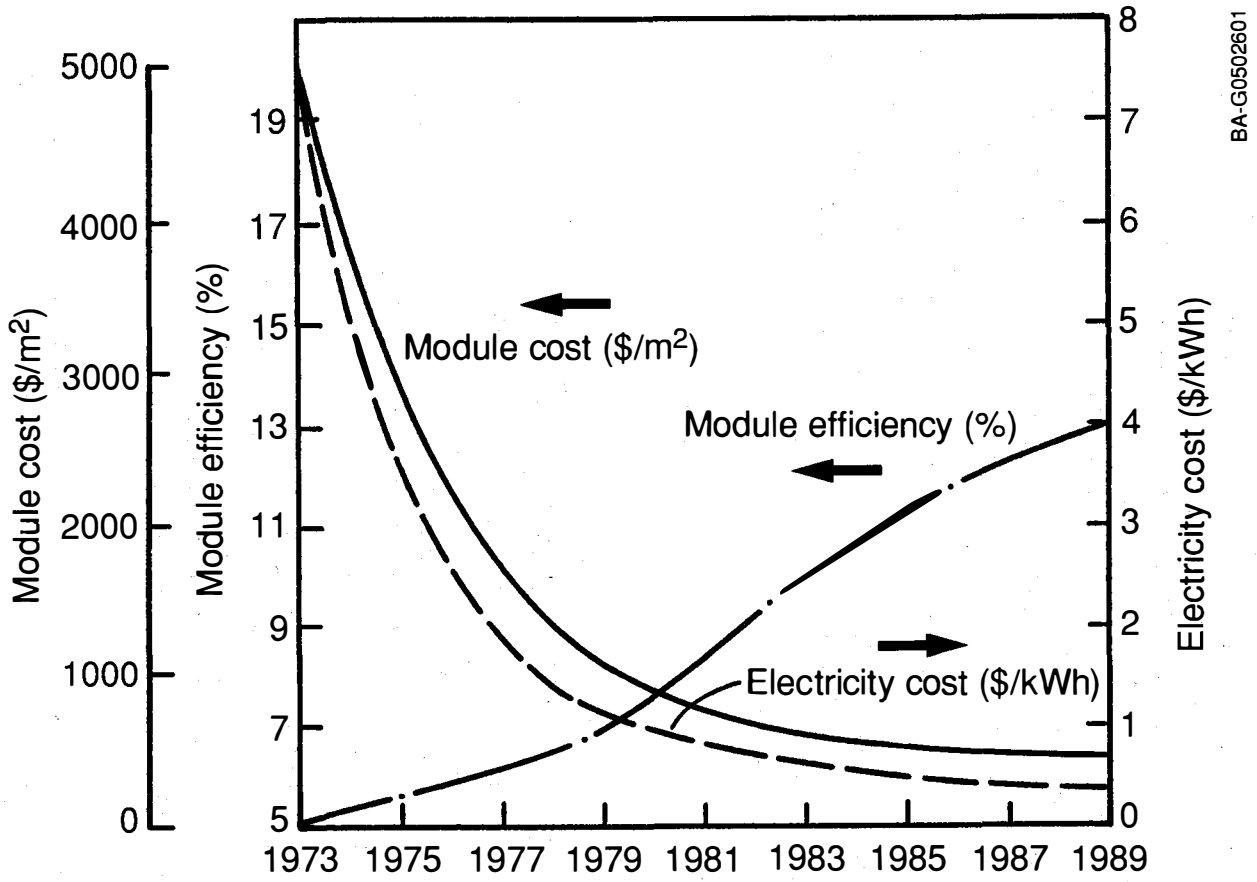

Figure 7. Progress in the Cost of PV Modules Drives the Cost of PV Systems

semiconductor material and metal contacts. During the last fifteen years, much work has gone into developing encapsulating materials (usually a transparent, plastic pottant and a front coverglass) that allow crystalline silicon modules to be used outdoors for long periods. We have reached the point where well-designed crystalline silicon modules have an outdoor life of 20-30 years. Just as module efficiency and cost are essential parameters defining the cost of PV electricity, module reliability is also an essential 'figure of merit'.

In addition to the progress in crystalline silicon, several new and promising PV alternatives have been developed over the last decade. Figure 8 shows some alternatives: advanced, high efficiency solar cells made to be used under focused sunlight in concentrators (top); new kinds of silicon cells made to replace those now used in flat-plate silicon modules (middle); and thin film cells as a low-cost alternative for flat-plate modules. Each of these technologies has economic advantages associated with it. But these opportunities are often at one pole or another of the cost/performance dichotomy. High efficiency devices tend to be costly. Low-cost thin films tend to be inefficient. Resolving these issues (raising the efficiency of thin films without a similar rise in cost, dropping the cost of crystalline silicon while maintaining or increasing efficiency) can only be done through R&D.

Figures 9a,b show how modules of various efficiencies and manufacturing cost can be compared in terms of the goals for making PV cost-competitive. The figures are calibrated in terms of module efficiency, module cost ($/m^2), and the resulting cost of PV electricity (assuming various costs for the rest of the system components). Two figures are given because concentrator and flat-plate systems are substantially different in terms of their hardware and their use of sunlight. (Concentrators require two-axis trackers; flat-plates are often most economical in fixed arrays.) The figures show that a variety of module costs and efficiencies can, in the long term, result in PV electricity costs of below 6 cents/kWh. These figures are from the DOE's Five Year Research Plan for PV and represent the result of a full economic analysis of PV systems, including support structures, land, installation, O&M, power-conditioning, dc-to-ac conversion, etc. This analysis (and the resultant Figures 9a,b) provides the baseline against which progress in PV can be measured.

Figure 8 showed that progress in improved cell efficiency has been steady and across-the-board among the PV options. This steady progress is a strength of PV, since it indicates that advances are not dependent on any single PV technology. One of the advantages of the U.S. effort in PV has been supporting the multiple option approach implicit in Figure 8. We have not become overly dependent (as have some) on any one option. Photovoltaic technology is at too early a stage to know with any certainty which of these PV options will reach our ambitious cost-competitive goals. Rather than undercut the future of PV, we support a number of good options and will await greater understanding to make choices among them. Photovoltaics is technology-driven: allowing scientists leeway in developing the best module technology is the best way to assure that PV eventually becomes a success.

But how does PV cell R&D translate into new PV products? Figure 10 is an example of the progress of thin films toward achieving cost-competitiveness at a practical level. Progress in cell efficiencies (Figure 8) is being translated into progress in product-sized modules. Several thin film cells (Figure 8, lower curve) have been successfully scaled up to 10%-efficient square-foot modules, demonstrating by proof-of-concept the potential of these approaches.

To put the results of Figure 10 into perspective, we must use Figure 9a. But to do so, we must understand the cost potential of thin films. Today's costs are of the order of hundreds of dollars per square meter. Various studies have been undertaken that show that the materials, equipment and labor costs of thin films would allow them to be made in volume at under $50/m^2. (See: Appendix of *National Photovoltaics Program, Five Year Research Plan*

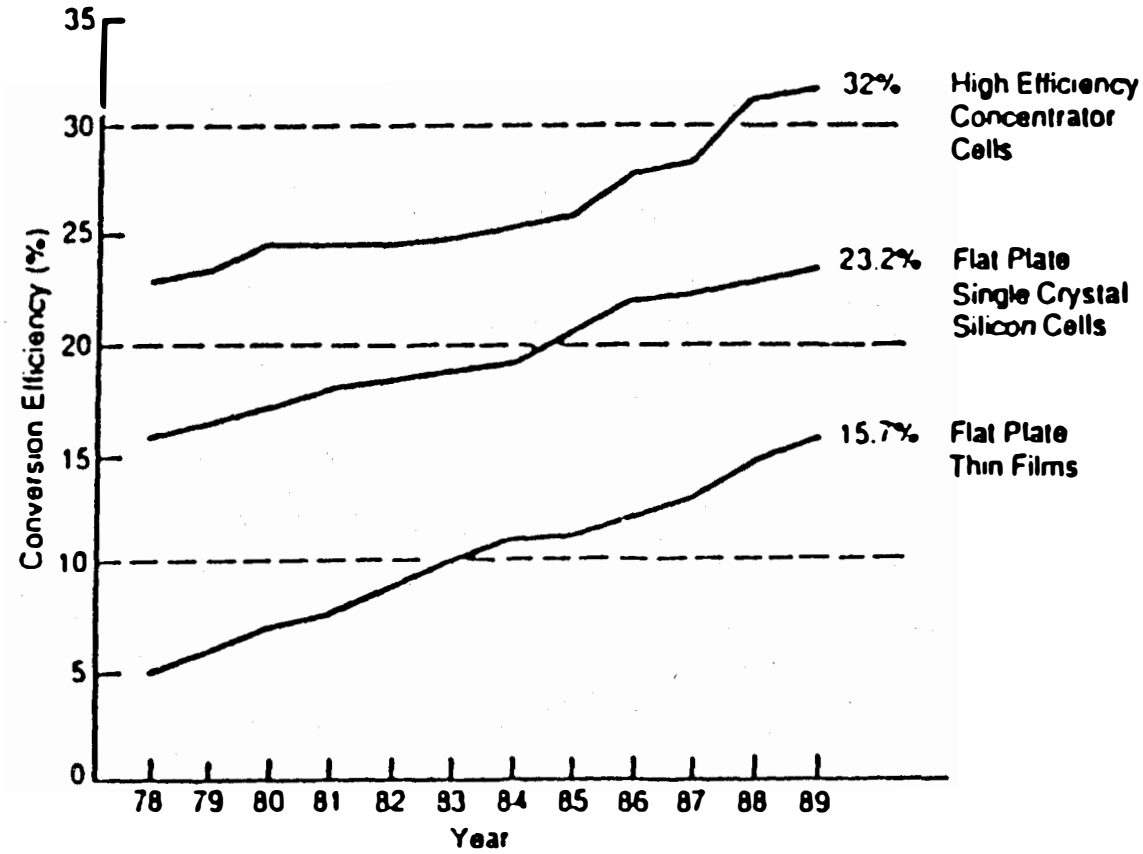

Figure 8. Progress in Efficiencies for Laboratory Cells

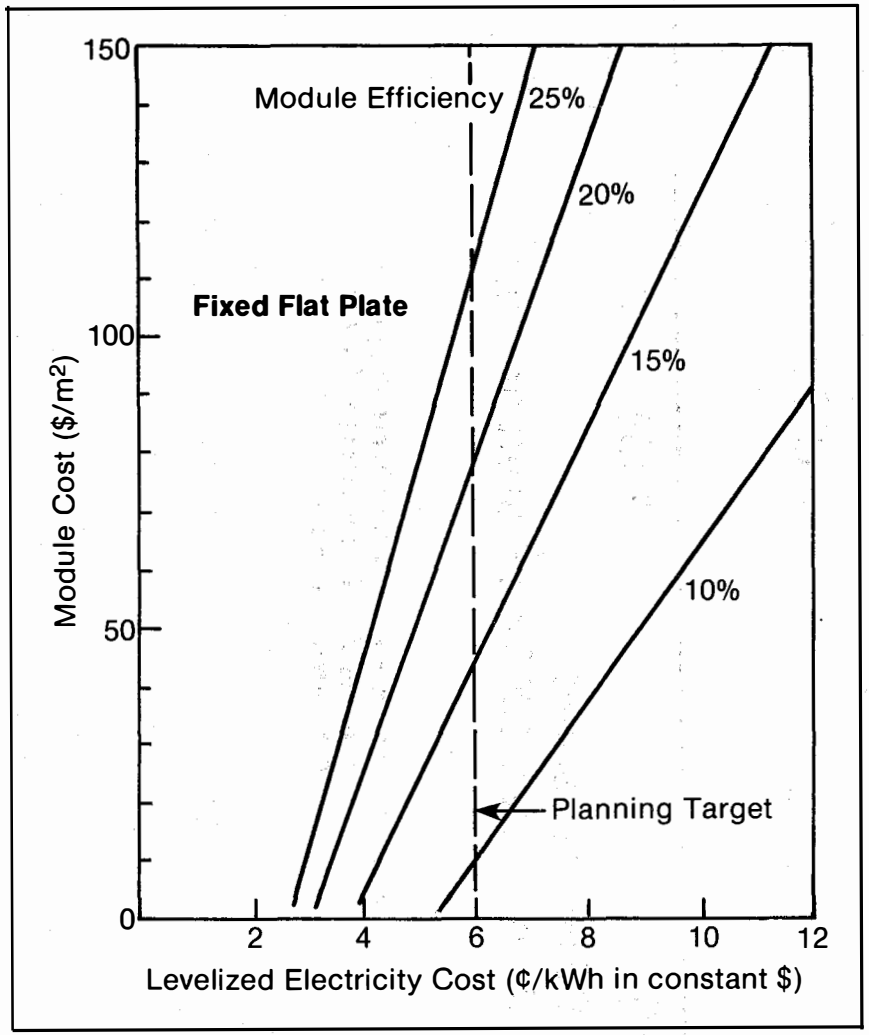

Figure 9a. Module Costs and Efficiencies vs 30-year Levelized Electricity Costs for Flat-Plate Photovoltaic Systems (fixed flat plate)

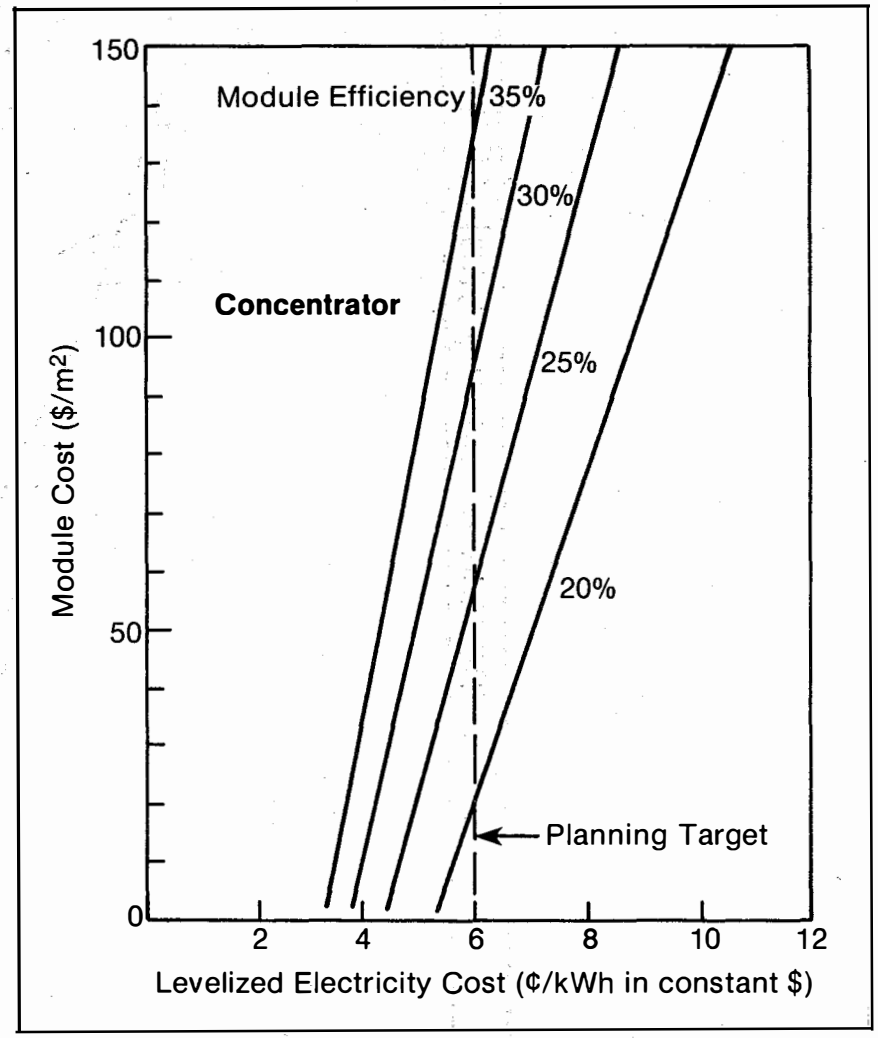

Figure 9b. Module Costs and Efficiencies versus 30-year Levelized Electricity Costs for Concentrator Photovoltaic Systems

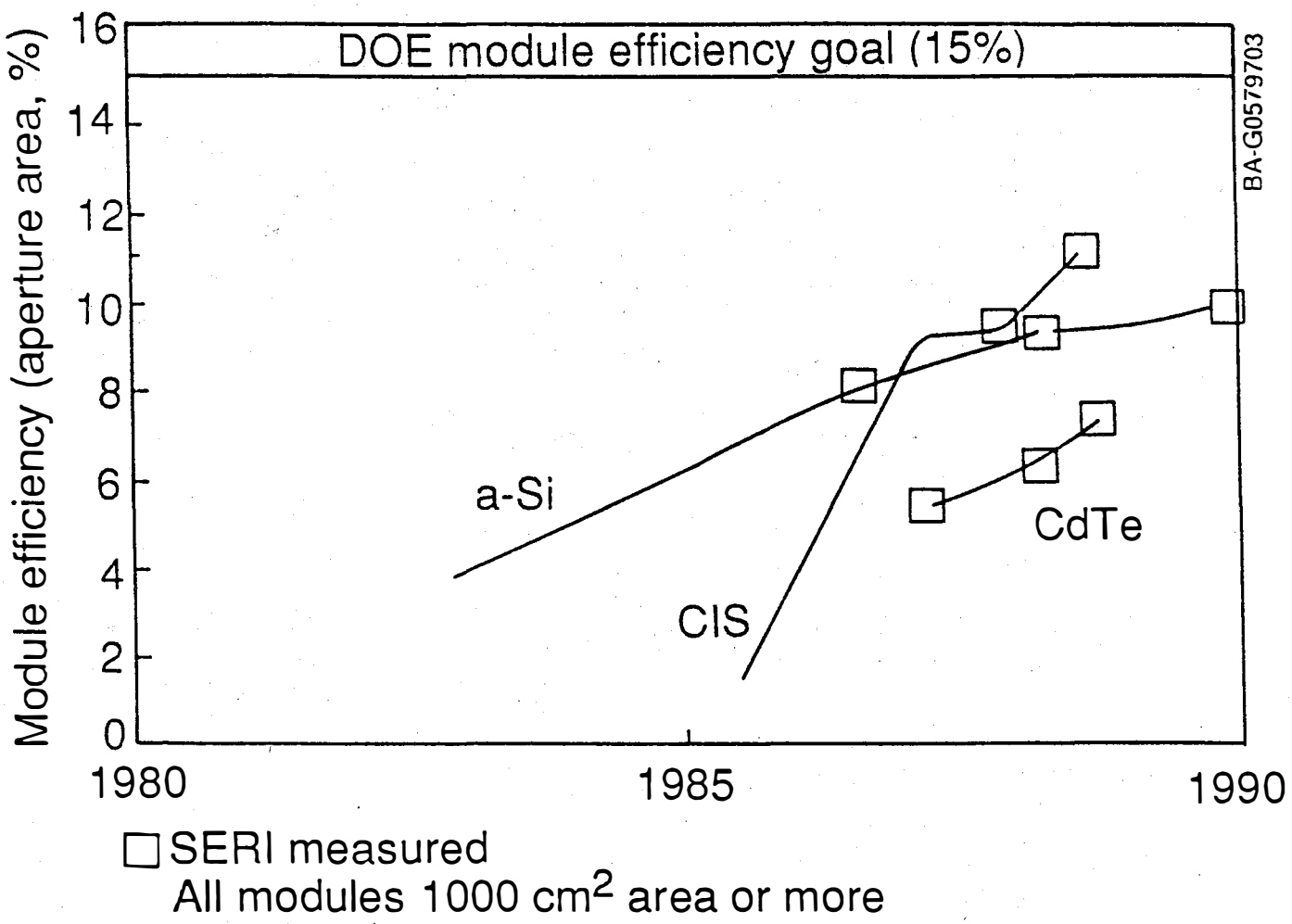

Figure 10. A Major Step for a New Technology Is Scaling-up Small, Laboratory Cells into Product-sized Modules.

1987–1991, U.S.DOE, DOE/ CH10093-7, May 1987; and "Harnessing Solar Power," Sept. 1990). In the nearer term, at manufacturing levels of about 3-10 MW of annual capacity, thin films will cost about $100/m^2 to manufacture. If we assume that thin films are 10% efficient, we can use Figure 9a to arrive at a cost of electricity of about 14 cents/kWh. Thus, the thin films of Figure 10 would be capable of reducing the cost of PV to about half of current levels (which are about 30 cents/kWh). This is an example of the substantial cost reductions in the offing due to research progress. Similar progress is going on across the technology field as major PV options move rapidly towards low cost production.

An important factor in reaching true low cost potential is manufacture on a large scale. Although making 15%-prototypes is a major part of the battle, making them in billion watt quantities is another key element. We will analyze PV economies-of-scale in greater detail in a subsequent section.

As we have seen, current PV costs are driven by the cost of PV modules. Progress in PV modules has been steady and impressive, allowing system cost reductions of over sevenfold since 1975 (Figure 7). Ongoing, consistent progress in reducing cost is heartening in that it bodes well for achieving the ambitious cost reductions still needed to make PV cost-competitive. Progress that has already been achieved in the laboratory on advanced PV options suggests that we may expect continued price reductions throughout this decade, especially as economies-of-scale are achieved in manufacturing. Cutting the cost of PV electricity in half is already 'in the bank' as far as the potential of existing PV module technologies (e.g., thin films) when they are manufactured on a reasonable scale.

3.0 Cost/Performance Projections

3.1 Base Case Funding

Table 1, Cost and Performance Detail: Base Case, shows the expected reduction in cost of a mid-sized PV system (10 MW) from 1990-2030. It assumes no change in funding levels from the present level of PV funding. Various assumptions go into the projections in the table. First, state-of-the-art PV systems today are based on crystalline silicon flat plates. The 1990 module costs (slightly under $4/W) are consistent with existing production methods of these modules. Total system costs are based on assuming $5/m^2 of aperture area for land (i.e., over $6000/acre--a conservative estimate), $15/m^2 for installation, and $60/m^2 for materials (trackers, etc.). Reductions in array field costs occur during the period through both increased system efficiency and improvements in array design. Power-conditioning costs are consistent with today's figures, and mass production and design improvements should reduce the costs of these components as shown. Power-conditioning costs include substation costs. Indirect costs are assumed to be about a third until 2000, when they drop to about a fourth of total direct costs due to experience and mass production. O&M costs of under 1 cent/kWh have already been demonstrated and should continue to drop as reliability issues are addressed at the system level during the period in question.

Progress in the base case is assumed to be based on the maturation of the crystalline silicon technology through the 1990s. Some stimulus for ongoing progress will arise from international sources that are independent of our assumptions for US funding levels. Unfortunately, such progress will come without a strong US component. Toward the end of the decade, thin films should be reaching a practical level, becoming a larger proportion of installed systems. The same will be true of concentrators, if they can be manufactured in sufficient quantity. From that point on, thin films will carry the costs to lower levels, due to incrementally increased efficiencies and major reductions in production costs. These will occur because processes will be improved and mass production will allow for significantly more automation. During the last

Table 1. Cost and Performance Details, Base Case Funding

Flat Plate Photovoltaics

COST DETAILS (in millions of constant 1990 dollars for a 10 MW System

Capital Costs						
	1990	1995	2000	2010	2020	2030
Major Components						
Modules	38.4	28.4	19.3	10	5.5	3.8
Array Field	6.7	6.7	6.7	5.3	4.7	4.4
Power Conditioner	3.0	2.5	2.0	1.5	1.0	1.0
Subtotal	48.1	37.6	28.0	16.8	11.2	9.2
Indirect	16.9	12.4	7.0	4.2	2.8	2.3
Total Installed Cost	65.0	50.0	35.0	21.0	14.0	11.5
Construction Time (yrs)	1	1	1	1	1	1
Operation and Maintenance Costs						
Fixed ($/MW)	---	---	---	---	---	---
Variable (cents/kWh)	0.5	0.5	0.2	0.2	0.2	0.1

Table 2. Cost and Performance Details, Accelerated R&D Funding

Flat Plate Photovoltaics

COST DETAILS (in millions of constant 1990 dollars for a 10 MW System

Capital Costs

	1990	1995	2000	2010	2020	2030
Major Components						
Modules	38.4	23.8	10.9	6.7	3.8	2.6
Array Field	6.7	6.7	6	5	4.4	4.0
Power Conditioner	3.0	2.5	1.7	1.3	1.0	.9
Subtotal	48.1	33.0	18.6	13.0	9.2	7.5
Indirect	16.9	10.0	4.7	3.3	2.3	1.8
Total Installed Cost	65.0	43.0	23.3	16.3	11.5	9.3
Construction Time (yrs)	1	1	1	1	1	1
Operation and Maintenance Costs						
Fixed ($/MW)	---	---	---	---	---	---
Variable (cents/kWh)	0.5	0.5	0.2	0.2	0.2	0.1

ten years of the period covered by Table 1, thin films will be in competition with advanced concepts like very high efficiency concentrators (cells over 40% efficiency). Both have the potential to evolve toward the assumed cost levels of the Table.

3.2 Accelerated PV R&D Funding

The accelerated R&D case can assure more rapid progress in PV as well as allow the US to play a dominant role in producing PV systems. In essence, the funding of more R&D during the 1990s would allow higher-risk options--i.e., options with greater low-cost potential--to progress more rapidly. Without increased funding, these same technologies would be too risky for US investors. Prototype production facilities would be hard to build. Large production facilities (10-50 MW) would probably not be built; and if they were, foreigners would own them (as they do many US PV facilities already). Thus the main value of increased funding is to reduce the investor-perceived risk of putting money into high-potential PV technologies; and it will allow their more rapid progress as well. By causing larger plants to be built, and by speeding the solution of key technical issues, increased funding would provide a much more rapid transition to the new options. This would help to assure even greater progress during the first decade of the 21st century for these same options. (Greater details of actual research paths and goals are given below.) The costs of Table 2 assume shifts from one technical option to another during the 1990-2030 period; in comparison with Table 1, the difference is that shifts occur sooner and progress is consistenly more rapid. Finally, the US position is strong in the accelerated case; in the base case, it could be almost nothing.

4.0 Rationale for Technology Improvements

PV will eventually cost as little as 5 cents/kWh (Figure 11). This expectation is consistent with other projections (the interlaboratory white paper on renewables, "The Potential of Renewable Energy," SERI/TP-260-3674, March 1990). But given the current cost of PV--about 30 cents/kWh--5 cents/kWh seems an ambitious goal. The factors behind the expected cost reductions are as follows:

- Ongoing module efficiency improvements;
- Development of new, lower cost manufacturing options; and
- Economies from large-scale manufacturing.

The industry status and the developmental requirements for achieving cost-effective PV are best described in the context of three categories of PV modules. These are:

1. Flat plate crystalline silicon (X-Si) modules, which include modules using either single or polycrystalline silicon solar cells;

2. Thin film modules, including amorphous silicon (a-Si) modules and polycrystalline thin film modules using semiconductors such as copper indium diselenide ($CuInSe_2$) or cadmium telluride (CdTe); and

3. Concentrator modules.

4.1 Flat Plate Crystalline Silicon Modules

This is the most mature and widely used of the three module technologies. The crystalline silicon cells used in these modules are typically about 100 square centimeters in area and about 300 microns in thickness. Crystalline silicon PV cells are made in a variety of ways, including

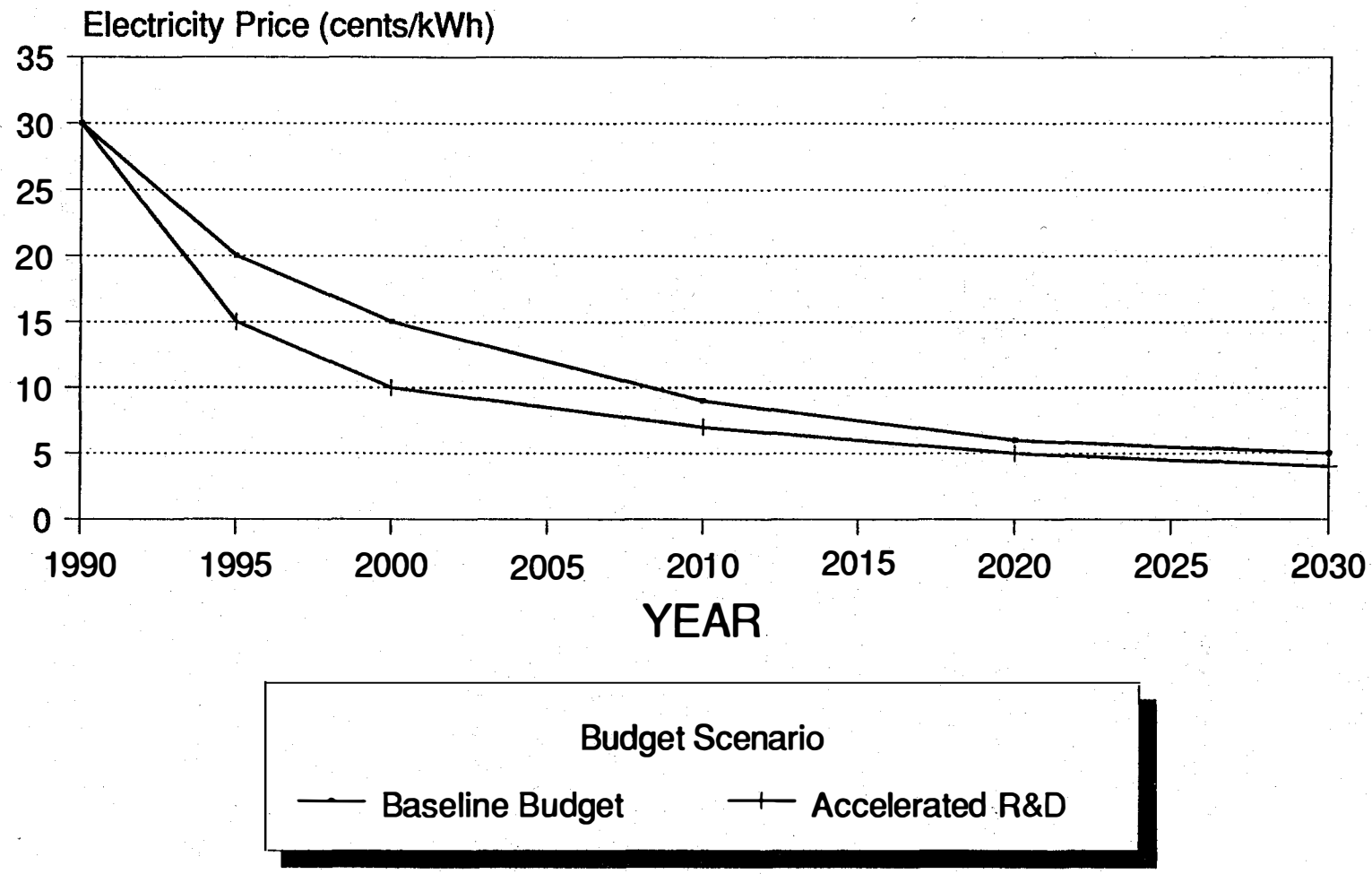

Figure 11. Projected Electricity Price

sawing Czochralski-grown single crystal ingots of silicon into wafers, sawing cast polycrystalline blocks of silicon into wafers, growing sheets of ribbon silicon in a variety of ways, and forming crystalline silicon sheets on substrates of other materials. Crystalline silicon cells have proven to have excellent durability, and thousands of X-Si modules have performed in PV systems for many years with no detectable degradation in efficiency. The major hurdle for this particular module technology is the cost of X-Si cells. Today, X-Si cells typically cost about $300-$500 per square meter. That cost needs to be reduced to below $100 per square meter. Although today's costs are dominated by expensive processing, X-Si materials represent the major costs left in trying to reduce modules to below $100/m^2. As Figure 9a shows, it then becomes important to have high efficiency X-Si modules.

There are two important paths for improving the cost-effectiveness for X-Si modules. The first of these lies in increasing efficiencies. As Figure 8 indicates, laboratory efficiencies of 23% have already been achieved for flat-plate X-Si cells. This suggests that it is possible to manufacture modules with efficiencies of 20%. In comparison with today's module efficiencies of 10% to 12%, this gain represents a power-based module cost reduction of 40% to 50%. Moreover, as efficiencies increase, these same cost reduction will also be realized for all of the area-related BOS costs, such as support structures, land, field installation, etc., since the required quantities of these will be reduced on a proportional basis.

The second path to reduced costs lies in the development of lower cost processes for producing sheets of crystalline Si. Several promising approaches are being pursued, including dendritic web Si, octagons of EFG Si, and thin film Si on ceramic, as well as several other concepts in other countries. Each of these has the potential of sharply reducing the cost of sheet Si required for flat plate X-Si modules.

Of course, a third path to lower costs for X-Si modules lies in lower manufacturing costs associated with larger volumes, which is discussed generically below.

4.2 Thin Film Modules

Thin films are semiconductor layers that are approximately 100 times thinner than the silicon used in conventional cells (which are about 300 microns thick). Savings associated with thin film modules include: (1) reduced materials; (2) the potential for high-throughput, continuous manufacturing processes; and (3) lower handling costs because thin films can be deposited over large areas and monolithically processed into modules.

Because thin films are designed for low cost, the most serious issue they face is achieving reasonable performance. Reaching module efficiencies of 15% is the main focus of the effort to develop thin films. This must be done while maintaining low cost by avoiding expensive processes or complex devices. Similarly, reliability is critical. Modules must be stable for 20 to 30 years.

Three thin films--copper indium diselenide (CIS), amorphous silicon, and cadmium telluride--were able to demonstrate 10% small-area cell efficiency in the early 1980s. Subsequently, DOE has supported enhanced programs for all three. Early on, the Japanese were able to use amorphous silicon cells to power "solar calculators," a new, high-profile market for PV cells. U.S. companies got into the act, pioneering the sale of outdoor lights and semitransparent car sunroofs. Companies scaled-up amorphous silicon modules to sizes in excess of 10 square feet. DOE has had major subcontracts with U.S. amorphous silicon companies--"government-industry R&D partnerships" (See Section 5.1, Government/Industry R&D Partnerships). This strategy is now our basic approach to stimulating PV progress in all technologies.

When thin film module technology becomes very mature, the cost driver will not be the semiconductor materials, but the glass on which modules are made. Window glass, like that which is used on the back of CIS devices, costs about $4/m^2$ in quantity; glass used on the front of the module is better quality and is closer to $6/m^2$ in quantity (J. Stone, E. Witt, R. McConnell et al., op. cit.). Total cost of glass in CIS devices is about $10/m^2$, still well under the $50/m^2$ allowable for the module. Semiconductor materials costs will be on the order of a few dollars/m^2, well below glass costs. Another "major" expense is encapsulation and framing, which total about the cost of the glass.

The cost of depositing the semiconductor layers varies with the cost of deposition equipment. Expensive, slow processes for depositing thin films are incapable of reaching ultra-low-cost. That is why much of the R&D effort of the DOE program is aimed at developing low-cost options such as spraying and electrodeposition of semiconductors. These low-cost processes are potentially capable of depositing semiconductor layers in seconds on moving substrates. Based on these rapid, low-capital processes, cost for making the key semiconductor layers is expected to fall below the cost of the glass on which the layers are made.

Theoretical efficiencies of thin films are in the range of 20%-25%. Practical cell efficiencies in the range of 17%-20% are achievable with incremental progress over existing cells (13%-14% today; see Figure 8). Thus no breakthroughs are required to reach expected module efficiencies of 15%. At $50/m^2$ costs, such modules would produce power at 33 cents/W ($50/150 Watts). Thus, in full production, thin film technologies should be able to supply modules for PV systems that would produce electricity as low as 5 cents/kWh.

4.3 Concentrator Modules

Photovoltaic concentrators offer the possibility of achieving very high solar to electric conversion efficiencies by using high-efficiency solar cells. The high cost of such cells is circumvented by the use of solar concentrators in lieu of large PV cell areas. The incorporation of concentrating optics and solar cells into a module design makes that design inherently more complex, however. Moreover, PV concentrators need to be mounted on sun-tracking platforms in order to maintain the focus of the sunlight on the concentrator cells. There are several approaches, special cell designs, high concentration, low concentration, passive tracking, and active tracking. One limitation is that the direct solar resource conducive to cost-effective concentrator operation is limited to the desert Southwest. In this way, PV concentrators have economic characteristics similar to solar thermal concentrators. The challenge for this PV module technology is to demonstrate that PV concentrators can be designed with the high efficiency and long-term durability and stability needed for economical power production.

PV concentrators inherently avoid the problem of needing to reduce the cost of solar cells since so little cell area is needed. Thus, the primary paths to lower costs are through higher efficiencies and manufacturing economies of scale. Already, PV concentrator module efficiencies above 20% have been achieved using Si concentrator cells, and these efficiencies are expected to permit module prices below $1/Wp in full production. Note that this only requires a price below $200/m^2$ on an area basis. The path to even higher efficiencies also appears clear, since concentrator Si cell efficiencies have already topped 28%, and multijunction concentrator device efficiencies have reach 34%. Even with optical losses of 10% to 15%, these indicate that module efficiencies of 25% to 30% are possible.

The manufacturing cost analysis for concentrators is somewhat more straightforward since concentrators are made of very common materials such as formed sheet metals and molded

plastics, similar to a multitude of commercial products. For this same reason, we can be confident that learning curve cost reductions will be realized for concentrators in larger production volumes.

That concentrators can achieve the necessary durability seems to be assured by the performance of several fields that were installed in the early 1980s. Both the SOLERAS 300-kW field in Saudi Arabia and the 25-kW field installed at the DFW Airport have exhibited good durability. The failures at SOLERAS have averaged about 3% per year, which is unacceptably high for a mature technology, but all of the failures have been attributed to quality control problems during manufacture or to design flaws that are easily corrected. The DFW system has shown no degradation.

4.4 Balance of System Costs

The term "balance of system" (BOS) is used to include everything, except the PV module. The costs of BOS include all direct costs for hardware and hardware installation—except the cost of the PV modules—the cost of structural materials and installation, field wiring, field fencing, power conditioning and control systems, and protection systems. They do not include costs of construction, engineering design, and construction project management. These are generally considered indirect costs. Thus, the total cost for a completely installed PV power system includes the cost of the PV module, BOS costs, and indirect costs, the latter normally being treated as a percent of the module and BOS cost.

There have been numerous studies of BOS costs which have generally had good agreement (Appendix of *National Photovoltaics Program Plan, Five Year Research Plan 1987-1991*, op. cit.). The result is that, as the construction of PV power systems matures, area related BOS costs are expected to reach these ranges:

- o $40 to $55 per square meter for fixed flat plate designs
- o $60 to $75 per square meter for 1-axis tracking flat plate designs
- o $100 to $125 per square meter for 2-axis tracking concentrator systems.

In addition, the costs for power conditioning subsystems are generally expected to reach the range of $0.08 to $0.15 per kW. Note that these costs are consistent with reaching PV energy prices in the range of 5 to 10 cents per kWh. Note also that the curves in Figure 9 incorporate these BOS costs. In summary, the expectations are that BOS costs will reach acceptably low values in the long term.

To summarize, the most important ideas to understand in terms of the low-cost potential of PV are that:

- o Existing device options do not come close to exhausting the theoretical potential of PV to achieve higher efficiencies;
- o Existing manufacturing of PV modules is more like jewelry-making than mass production because markets are so tiny that manufacturers cannot achieve reasonable economies-of-scale;
- o In the long-term, PV manufacturing costs will resemble the cost of material feedstocks. For the case of thin films, these costs are so small that they are dominated by such inexpensive commodities as window glass. Costs well under those needed to make PV very inexpensive ($50/m^2) should be attainable.

4.5 Implicit Production Levels

The cost of energy from photovoltaic power systems (currently in the range of 30-40 cents per kWh) must be reduced by a larger factor than for any of the renewable electric technologies. Achieving an energy cost of 10 cents per kWh by the year 2000 is an important threshold for photovoltaics in order to penetrate U.S. utility markets during a window of opportunity when added utility generating capacity needs are projected to be high. This reduction is expected to result from the combination of a productive R&D program and rapidly increasing commercial sales of PV products over the next decade.

The implicit production levels during the next decade which are necessary to achieve the year 2000 utility-market threshold have been estimated using a learning curve methodology. Learning curves are known to apply to a variety of manufactured products, especially those whose accumulated production experience spans several orders of magnitude.

The learning curve used to establish the relationship between production level and cost for photovoltaic power systems is shown in Figure 12. It illustrates a relationship between accumulated worldwide production experience and levelized energy cost for photovoltaics. The historical decline in cost of energy from photovoltaic systems shown in Figure 12 has occurred at a rate of 32%. That is, the cost decreases 68% for each order of magnitude increase in accumulated production experience. This result tracks the analysis of many others who have applied learning curves to photovoltaic module prices and generally find learning rates (1 - cost reduction) between 30% and 35%, typical rates for technologies undergoing rapid innovation and maturation.

The data points representing energy cost versus production experience which have been used in the Interlaboratory White Paper on the Potential of Renewable Energy are also shown in Figure 12 for the three baseline assumptions. A cost reduction curve starting at 15 cents per kWh and an accumulated production level of 1 GW_p, with a cost reduction rate of 40% over the next three decades of accumulated experience, describes these points quite accurately. A 60% learning rate (corresponding to a 40% cost reduction rate) is feasible for a relatively mature technology.

The critical connection to be made over the next decade is to bridge the historical portion of the curve to the projected energy-significant portion of the curve through R&D advances and market growth. Specifically, the challenge is to reduce energy cost from 30-40 cents/kWh to 10 cents/kWh while increasing accumulated production experience by the year 2000. This implies a continued cost reduction rate of about 60% - 65% over this period, a reasonable expectation for a technology undergoing active research and innovation.

The current worldwide annual sales of photovoltaics is about 50 MW_p, and the accumulated production experience is about 100 MW. Photovoltaic annual sales have been increasing 25% to 40% per year over the past several years. At an annual growth rate of only 15% to 20% per year over the next decade, the accumulated worldwide production experience will exceed 1 GW_p by the year 2000. Some projected markets that would sustain sales growth over the next decade are shown in Figure 13 and come mainly from new and expanded use of photovoltaic power systems in a variety of cost-effective applications by utilities. This analysis supports the likelihood that PV costs will continue along the learning curve toward the range of our projections.

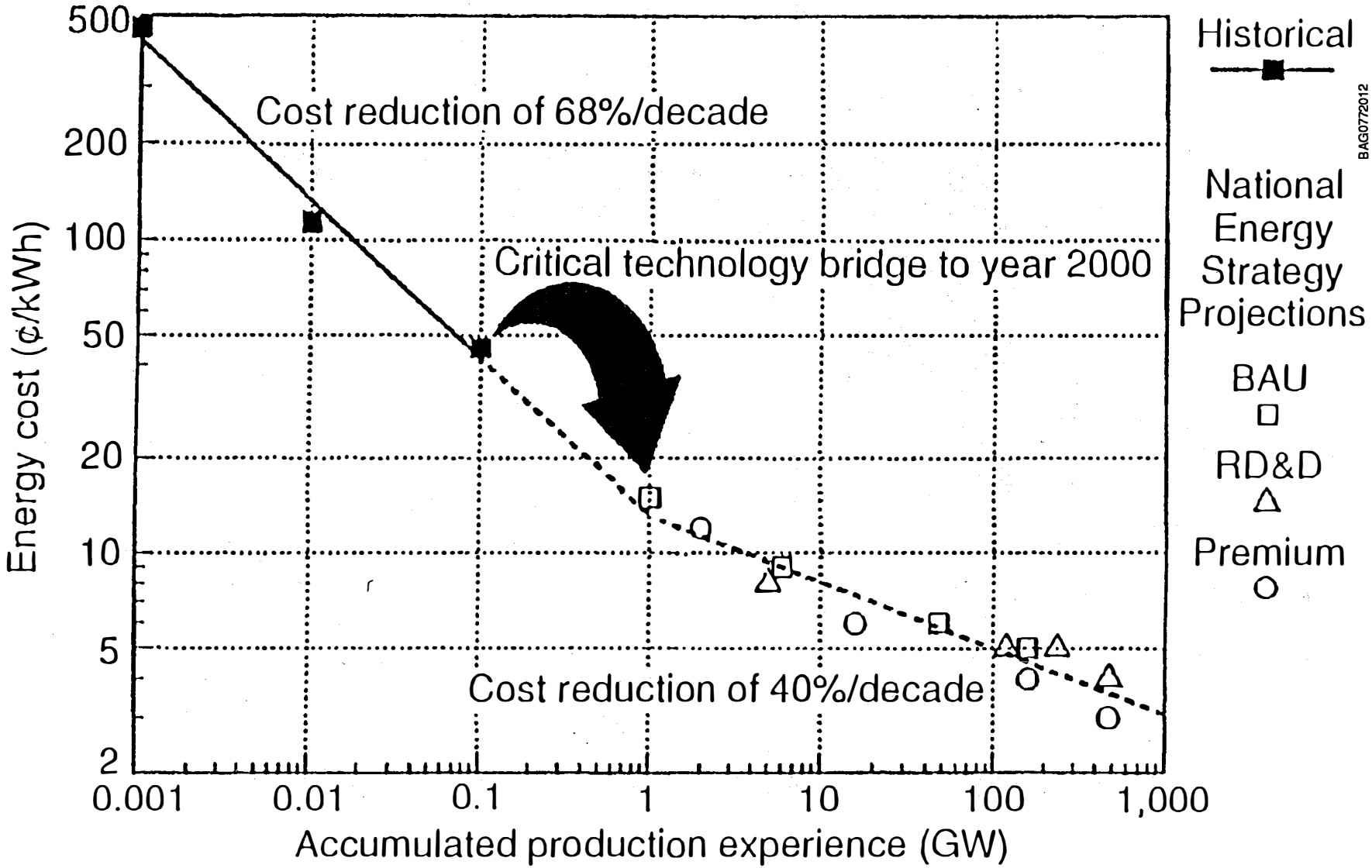

Figure 12. Learning Curve for Photovoltaic Power Systems

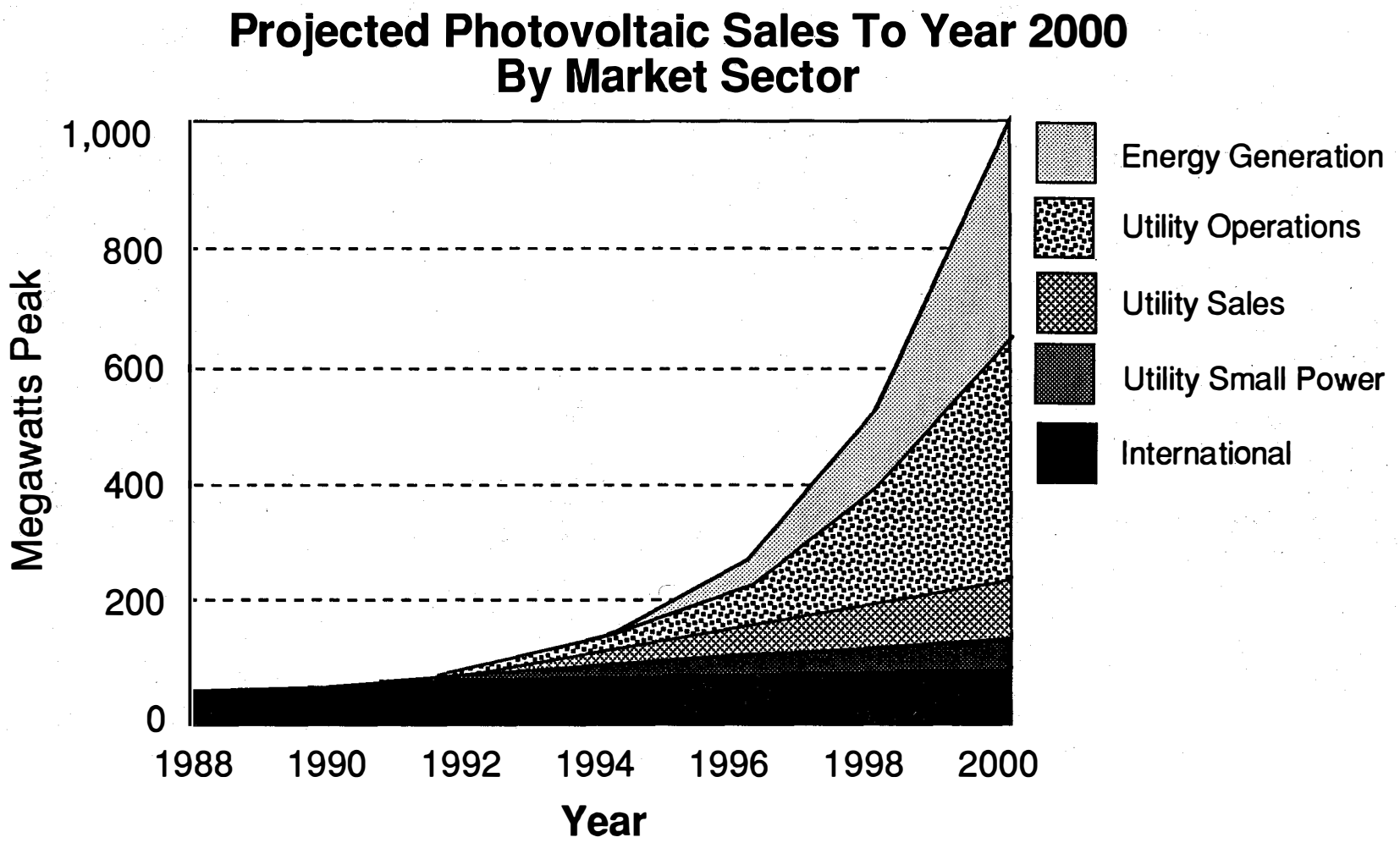

Figure 13. Near-term Market Penetration of PV

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5.0 R&D Opportunities for Cost/Performance Improvements

Our research for the next five years (corresponding essentially to the base case analysis) will be organized around five major tasks. Fundamental and Supporting Research addresses problems that cut across different PV technologies, involving basic scientific and engineering questions, resource assessment, and measurements and testing. Environmental, safety, and health issues are also studied under this task. In Advanced Thin Films, researchers work to improve the technology of thin-film photovoltaic modules made from several different thin-film materials.

High-Efficiency Materials studies crystalline silicon and gallium arsenide cells and modules, striving for even better performance and lower cost in commercial modules. Module Development looks at the design and integration of module components, and the effect of manufacturing processing techniques, for all types of modules. Systems Development addresses problems arising when PV modules are integrated into entire systems, collects performance data on existing systems, and advises potential users.

5.1 A Key Strategy: Government/Industry R&D Partnerships

The DOE National Photovoltaics Program has always solicited the active participation of the PV industry, considering it the best means of assuring effective "technology transfer" of government-funded advances in PV. Over the years this intention has evolved into a strategy of actually developing government-industry partnerships. By this, we mean cost-shared contracts between the government and PV industry participants. In these contracts, cost-sharing acts as a means of assuring the proper expenditure of government funds (since companies would have little incentive to co-fund irrelevant projects) and also acts as a guide to the commitment of the funded company, since those that are willing to risk their own capital are more likely to have the tendency to fully develop their technology.

Another important aspect of the government-industry partnership approach is that it stimulates competition in the private sector. We always fund more than one corporation. In fact, we fund many companies in many different technologies. Individually, they must stay at the leading-edge of PV development to remain competitive. By fostering active competition among the most advanced technologies, we stimulate rapid technical progress.

Partnership contracts have been engaged in by DOE as a central strategy in assuring the progress of critical PV technologies. They were used early on (late 1970s), when crystalline silicon was in its most formative developmental phase. Since 1983, the National Program has supported several initiatives in advanced thin films, as well. A series of government-industry partnership contracts were issued by the Amorphous Silicon Research Project (see text within the Advanced Thin Film task). These led to the development of U.S. leadership in this technology. During the same period, a similar set of programs was also carried out in CIS and CdTe, but at lower funding levels. Those levels are being increased, and the National Program is now allocating a larger portion of its funds to government-industry partnerships to develop CIS and CdTe. The aim is similar: U.S. technical leadership. Another initiative to develop government-industry partners is also beginning in the concentrator systems area, which has shown great promise of cost reductions.

The strategy of engaging industrial partners in order to assure the most rapid progress in PV technology is being extended in a major way via a new initiative, the PV Manufacturing Initiative. This $55 million initiative will carry the partnership approach to a new level, with the aim of significantly advancing U.S. PV manufacturing capability and increasing the U.S. industry's world market share.

5.2 Fundamental and Supporting Research

The primary goal of Fundamental and Supporting Research is to provide a strong foundation to the scientific and technical knowledge base for photovoltaic materials and devices. Several scientific and engineering disciplines support this task, including theoretical solid-state physics, device physics, chemistry, material science, and optics. Universities, industry, and government laboratories work together on many subcontracted or collaborative research projects in these areas.

To provide a strong foundation of knowledge in photovoltaics, we emphasize two types of research efforts: fundamental and supporting.

Fundamental Research Projects

Fundamental research projects provide insight into the most basic scientific questions underlying photovoltaic technology. They include our New Ideas for Photovoltaic Conversion Project, the University Participation Project, and theoretical and experimental solid-state physics projects.

New Ideas. The New Ideas for Photovoltaic Conversion Project identifies innovative approaches to existing technology, new materials, new device configurations, or new photovoltaic concepts. We periodically issue requests for letters of interest to identify new concepts. The most promising receive research funding for one year. If a concept shows significant potential, it is supported for one more year, and then transferred to the appropriate major photovoltaic program for extended support. To date, more than 50% of the initial research conducted under this program has been worthy of further research funding, patents, or commercial product development.

University Participation. The University Participation Project attracts highly qualified university research teams to the National Photovoltaic Program to do research in a non-goal-oriented environment. Since the project began in 1985, we have made 12 subcontract research awards. The project provides continuous funding over a three-year period, allowing universities to build and support multidisciplinary teams. It also helps train graduate students for further careers in the photovoltaic community.

During the next five years, work will continue on current projects in the New Ideas and University Participation Programs. There will also be new solicitations in 1991, 1993, and 1995.

Supporting Research Projects

Supporting research projects include activities that cut across the technologies, including modelling and analyzing solar cell materials and designs; measuring and testing materials, cells, and modules; studying solar radiation characteristics; and studying environment, safety, and health issues raised in photovoltaic manufacturing.

Solid-State Theory. The solid-state theory research effort brings state-of-the-art condensed matter theory into the realm of photovoltaic materials. Unlike that of simple devices such as transistors, the performance of solar cells depends on a very large number of material characteristics and interactions that are difficult to isolate. Solid-state theory helps us to develop a fundamental understanding of solar cell performance by modelling the electronic structure of prototype systems that isolate these complex relationships. Knowledge gained through these studies can be applied to the design of novel photovoltaic materials. It also allows us to analyze the properties of existing materials. During the next five years, we expect

to develop new techniques for theoretical research, and to use these tools to theoretically design new materials.

Characterization and Testing. Measuring and testing materials, cells, and modules is vitally important not only to the research done at the DOE laboratories but also to the research done throughout the photovoltaic community. We examine tens of thousands of samples from government laboratories and from industry each year. Characterization methods extend from the macroscopic evaluation of modules to the atomic-level imaging of molecules. In addition to routine diagnostic information, the laboratories have special capabilities to link events observed on the atomic scale with the macroscopic performance of cells and components.

As part of our commitment to providing these analytical services, we have developed many new characterization techniques, some of which have won honors such as the R&D 100 award. Some of these characterization techniques have been transferred to the private sector. We also act as a referee, confirming cell and module measurements made by others.

During the next five years, we will continue to provide analytical services to DOE researchers and the photovoltaic community and to develop new analytical techniques. We also expect to upgrade some of our critical equipment that is becoming technically obsolete. It is essential for us to maintain or reestablish state-of-the-art equipment for characterization and testing and for material and device fabrication.

Solar Radiation Research. Research on the solar radiation resource is the foundation of cell, module, and system evaluation. Because of atmospheric effects such as clouds and aerosols, neither the amount of solar radiation nor its spectral (color) content are constant. Designers and users of PV cells and modules need to know how these solar radiation variations affect the energy produced by their devices. Measurements of solar radiation are also critical for testing and evaluating modules outdoors.

We work closely with the photovoltaic community and with organizations such as the National Climatic Data Center to devise specialized instruments, to develop measurement procedures, and to gather and distribute data on the geographic variations in solar radiation. During the next five years we have four major goals. The first is to produce a 30-year (1961-1990) solar radiation database for the United States; the second is to work with the National Oceanic and Atmospheric Administration and other groups to collect high-quality solar radiation data for the United States. The third goal is to produce a research-quality spectral solar radiation data base and spectral simulation model for various climate conditions; the fourth is to maintain our expertise as the nation's lead center for solar radiation resource assessment.

Environment, Safety, and Health. The goal of the Environment, Safety, and Health subtask is to ensure that these issues are carefully considered during the development and commercialization of photovoltaic technology. We work proactively with industry and other federal organizations (such as the Environmental Protection Agency and the National Institute for Occupational Safety and Health) to evaluate hazards presented by various PV technologies and to advise on alternative ways to manage these hazards. Industry is a very close partner in this effort. We expect to continue this work during the next five years, including sponsoring a photovoltaics safety conference.

5.3 Advanced Thin Films

Thin films are semiconductor layers that are much thinner than the silicon used in conventional cells. Thin-film modules are expected to be lower in cost than conventional modules because

they use less material; they have potential for high-throughput, continuous manufacturing processes; and they will have lower handling costs.

The main thrust of the Advanced Thin Films research task is to reach module efficiencies of 15% while maintaining the advantages that tend to lower costs. Achieving 20- to 30-year reliability is also a critical goal. During the next five years we will be developing four thin films: amorphous silicon, copper indium diselenide, cadmium telluride, and thin-film silicon.

Amorphous Silicon. Amorphous silicon devices have the disadvantage of light-induced instability. With exposure to light, the efficiency of the devices gradually decreases. The problem of cell instability has been a major focus of our research. We have developed ways to ameliorate it but not to solve it. A key strategy is to make the amorphous silicon layers thinner, an approach we expect will confine degradation losses to 10%. The focus of the amorphous silicon program is on achieving high efficiencies while minimizing the instability to about a 10% loss.

The goal of increasing efficiency has led to an innovative multijunction structure for amorphous silicon devices. Multijunction devices contain a stack of individual PV cells in which light that is unused in top cells can be used effectively in the lower ones. We are also developing two- and three-junction amorphous silicon. Research efforts will continue to characterize and improve various types of amorphous silicon materials and devices.

Copper Indium Diselenide (CIS). One of the major strengths of CIS technology is that it appears to have few if any instability problems. Testing for 500 days showed almost no change. A focus of our R&D efforts will be to establish whether CIS modules can be as stable as crystalline silicon.

Based on analyses of theoretical loss mechanisms, single-junction CIS cells have the practical potential of achieving 18%-20% efficiency, allowing the fabrication of modules more than 15% efficient. Research efforts in CIS will address cell design and materials issues to optimize cell efficiencies. We will investigate various other alloys, such as incorporating gallium to replace indium and sulfur to replace selenium. Successful modifications will be incorporated into larger devices. The critical issue in manufacturing larger modules will be uniformity over large areas and high process yields.

During the next five years we will address a number of critical technical tasks. We expect to have a prototype module capable of competing for remote and peak power applications at the end of the planning period that is 13% efficient, 4000 square centimeters (or more) in size, and susceptible to less than 5% degradation over a 10-year period.

We also expect continued progress in reducing cost of manufacturing these modules. Systems using 13%-efficient, thin-film power modules should be able to produce electricity at about 12 cents per kWh. Economies of scale and some development of lower-cost processes for depositing CIS and molybdenum will allow us to bring module costs down to $50 per meter or less. In full production, thin-film technologies could be used in PV systems that would produce electricity at 5-6 cents per kWh during the first decade of the next century.

Cadmium Telluride (CdTe). CdTe technology has a mixed reputation in terms of stability. At the cell level, contact diffusion effects are of concern, but recent work in innovative n-i-p designs has been very promising. At the module level, humidity ingress could be an issue. Preliminary outdoor test results are promising, with CdTe modules showing about the same durability as CIS modules during their initial half-year outdoors.

In terms of practical, long-term efficiencies, CdTe actually has a slightly higher potential than CIS. Our research efforts will focus on increasing the efficiencies of cells towards their practical maximum of 20% and increasing the efficiencies of CdTe modules. Our analyses of existing methods of depositing CdTe (e.g., spraying and electrodeposition) suggest that they are among the lowest cost methods of making thin films.

Thin-film crystalline silicon. Processes for depositing silicon on substrates have been developed and experimental cells produced. Our goals are to make larger-area cells and to interconnect the cells without numerous handling steps.

Institutional issues. Some thin-film technologies use small amounts of hazardous materials and materials that may not be available in the quantities needed for large-scale usage. With the help of Brookhaven National Laboratory, we will look for ways to understand and manage these risks, such as avoiding feedstock losses during manufacture, making thinner layers, and finding substitutes where possible for critical elements.

5.4 High-Efficiency Materials

High-efficiency materials are crystalline semiconductors including silicon, gallium arsenide, and related compounds. The intrinsic stability of crystalline materials has been well established by the performance of a wide variety of semiconductor devices and the long-term operation of high-efficiency PV modules. With efficiency, stability, and an extensive research infrastructure established, we will focus our efforts predominantly on developing lower-cost cell designs and developing manufacturing processes that exploit the current level of scientific understanding of these materials.

Crystalline Silicon Technology. The low-cost production materials available today do not provide the purity or crystalline perfection of the float-zone silicon used for laboratory device research. But we can increase the efficiencies of commercial cells using our knowledge of the limitations of device design and the interactions of processing steps with defects and impurities in the material. We will assist industry with these improvements in three specific research areas.

In the first area, we will extend our understanding of the nature and magnitude of the effects of defects in crystalline silicon. This knowledge will be essential to analyzing the performance trade-offs inherent in designing fabrication sequences.

In the second area, we will study the interaction between specific processing steps (such as cleaning, texturing, and diffusion) and various grades of silicon under controlled conditions. The analytical capabilities at SERI and Sandia will be used to characterize materials processed by industry. This collaborative research will guide the improvement of the solar cell fabrication sequence.

In the third area, we will build on the previous two areas, along with ongoing high-efficiency device research, to improve overall fabrication procedures on a company-specific basis.

Advanced Materials and Devices. To help improve the quality of today's commercial materials, we will explore the fundamentals of growing silicon crystals at high growth rates while yielding very pure, high-quality material. This will require characterizing the thermal and mechanical properties of silicon near its melting point. Several promising techniques will be evaluated for their performance and cost-effectiveness.

In high-efficiency cell research, we will investigate the application of new fabrication processes to thin photovoltaic cells. These processes, such as lateral epitaxy and seeded recrystallization, have produced high-quality crystalline thin films. And while the cell materials researched to date (silicon, gallium arsenide, and related compounds) have great promise for thin cells, we will explore other materials as well.

High-efficiency device research enables us to better understand the electronic processes that occur in these devices and to better control the efficiency loss mechanisms. Improving our understanding of solar cell theory is allowing us to help improve the design of cells made from less-than-ideal materials and to understand the effects of different processing options.

Concentrator Cells. The research issues pertinent for high-efficiency, one-sun cells also apply to concentrator cells. We will continue to address problems specific to concentrator cells, such as how to lower series resistance to accommodate the higher current generated by concentrated sunlight, without increasing the shading caused by larger grid lines. Another issue we will study is how to apply advanced cell technology to the commercial manufacture of module-ready cells. The Photovoltaic Concentrator Initiative, begun in 1990, will continue through the first years of the next five years.

5.5 Module Development

Our goal is to develop both the collector module technology and the manufacturing technology for producing cost-effective photovoltaic modules. Concurrent engineering is necessary in these areas to be sure that modules are designed for automated, low-cost manufacturing with high yields and excellent product quality. Some of the areas being addressed include module design, module efficiency improvements, yield, throughput, scaling to larger areas, more efficient use of materials or substitution of cheaper materials, and the introduction or greater use of automation and robotics.

The Photovoltaic Manufacturing Technology Initiative (PVMaT) will be a major effort over the next five years. The goal of this government/industry partnership program is to reduce production costs by a factor of 2 or 3 from current levels through advances in manufacturing technology.

Flat-Plate Crystalline Silicon Modules. Although this is the most mature and widely used of the three PV module technologies, module prices must be substantially lower in order to compete with other electric power technologies. Besides lowering the cost of the cells that go into the modules (as described in the previous section), there are also opportunities for lowering module costs by automating and integrating cell processing with module manufacturing. Through cost-shared research with industry, we will work towards this goal. We will also continue to evaluate modules for their durability and reliability, and address issues in those areas as the need arises.

Thin-Film Modules. Because of the way cells are produced (by depositing thin films), cell and module manufacturing is inherently integrated in thin-film technology. We will concentrate on module development activities that include mechanical and electrical design, encapsulation, evaluation, and reliability testing. In the area of manufacturing technology, we will emphasize the design and development of large-area deposition and processing equipment and material handling systems.

Concentrator Modules. Concentrator modules are significantly more complicated than flat-plate modules and need more development to ensure the best performance of the cells, cell

assemblies, and concentrator optics. They also require that we develop low-cost, sun-tracking array support structures.

The DOE PV Program has already started an agressive cost-shared program called the Concentrator Initiative which is aimed at supporting the development of a viable commercial concentrator industry. Working with industry, we will develop module components such as Fresnel lenses, secondary optical elements, cell assemblies, and module housings. Integration of module design with manufacturing technology will also be very important, as will module evaluation and reliability engineering. The result of this Initiative is expected to be the establishment of an industry that can install PV concentrator power plants with energy generation costs of 10 to 15 cents per kWh by 1995.

General Testing, Evaluation, and Development. We also test and evaluate modules and study general problems that affect all types of modules. During the next five years, we will continue measuring electrical performance characteristics, testing durability, analyzing the failures of modules, collecting performance data, working with industry to set electrical and performance standards, and other general activities. These activities will help to develop modules that will meet performance, safety, and reliability requirements.

5.6 Systems Development

Under Systems Development, all elements of the technology are integrated to successfully produce cost-competitive electricity. Our goals are threefold: to develop the system and balance-of-system technologies for cost-effective applications; to assess field performance of systems and components; and to disseminate this information to industry and potential users to accelerate the acceptance of PV technology.

System Field Performance. Since the late 1970s, we have maintained comprehensive performance information from systems throughout the country. Remotely monitored on-site instrumentation and periodic system field surveys have provided valuable data on performance, reliability, and operational costs. Evaluations of the performance of systems will continue throughout the country, focusing on new collector technologies and power-processing hardware. s more projects are initiated, power conditioning and systems control will become important project issues. We will also expand our evaluation activities on stand-alone systems and components.

We will also continue to be actively involved in the PVU.S.A project. Nearly 1 MW of arrays and systems will be installed at the PVU.S.A test site in California by mid-1991, which represents a tremendous opportunity to compare the performance of various technologies under utility operating conditions.

Power Processing Hardware. We have conducted extensive tests of commercially available power-conditioning equipment and charge controllers. We plan to initiate a cooperative effort with the power-processing industry to expand and improve the usability of this hardware. Issues to be addressed include control circuitry, product quality control, increased efficiency, reduced cost, and development of 30- to 50-kW equipment for use in remote village power applications.

Utility Acceptance of Photovoltaics. Meeting an acceptable economic threshold will not be enough to convince utilities to begin using photovoltaic systems for peak or bulk power generation. The utility industry must also become familiar and comfortable with photovoltaic power generation.

During the next five years, we intend to pursue a strategy to accelerate the utilities' acceptance of photovoltaic technology. In close coordination with the Electric Power Research Institute and the photovoltaics industry, we will identify high-value applications within utilities and carry out demonstration projects to verify these applications. These efforts are discussed further in Appendix A.

Design Assistance Center. The goal of the Design Assistance Center is to accelerate the acceptance of photovoltaics worldwide by helping industry educate the potential user about the benefits and use of the technology. Nearly 100 different public and private organizations have received substantial assistance during the past three years, and requests for assistance continue to grow. During the next five years we will continue to expand our technology transfer activities by developing new user-oriented publications and by consulting directly on projects for an increasing number of technology users.

6.0 Technology Policy Opportunities

This section concerns the best opportunities in R&D for accelerating the cost reduction in PV electricity. In contrast to Section 5, it corresponds to the accelerated research and development case. In that case, we see real opportunities for accelerating cost reduction if the National PV Program budget were to be rapidly ramped upward to three to five times its current level (i.e., to about $100-$150 million/year), with a major portion of this increase allocated for demonstrations.

The heart of the approach to reducing the cost of PV is the successful development of a low cost PV module technology. We have stated that a balanced approach is the best at this time for a variety of reasons:

- Many module technologies (thin films, crystalline silicon, concentrators) are making rapid progress and show no signs of exhausting their potential;
- It is too early to be certain that any single module technology will succeed completely;
- Previous attempts by national programs or corporations to 'pick a winner' among the various PV module technologies have been counterproductive, actually holding up the successful development of low-cost PV;
- Finally, it may be that *several* module technologies will succeed and that their success will be complementary, i.e., they will satisfy different niches or act as competing choices (keeping prices lower).

Thus, the first principle of accelerating PV development is to continue and to enhance a balanced R&D program. Such a program consists of everal aspects: the core R&D program, manufacturing R&D, and demonstrations.

The Core R&D Program is the foundation upon which the entire program rests. We define it as all aspects of the R&D program that support development of prototype modules. It includes:

- Fundamental R&D at universities, SERI, and Sandia;
- Solar resource assessment;
- New ideas R&D;
- Government/industry partnerships in the major PV module options;
- Cross-cutting support R&D (characterization & analysis) at SERI and Sandia;
- University programs to support students and centers of excellence; and
- Program management and analysis, information services, administrative support.

At the center of the core program is an effort to work with the U.S. PV industry--the best vehicle of PV development--to carry through the evolution of module technologies from their inception as small, laboratory cells to large-sized, product prototypes. Imbedded in this process is semiconductor materials research as well as innovative process research for making large-area, uniformly high-quality semiconductors. It is through the government/industry partnership program that these critical module technologies are brought to fruition. This program starts with SERI or Sandia subcontracts to industry that help develop new cell concepts. Once these concepts have reached proof-of-concept (e.g., 10% cells for thin films), the subcontract amounts are increased to support the next step: process development for large-area (up to 1 m^2) submodule prototypes. These same contracts from SERI or Sandia require cost-sharing (20%-50%) and represent true risk-sharing between the DOE and corporations.

Although the government/industry partnerships drive the core program, it is also strongly supported through R&D at SERI, Sandia, and other national labs. Efforts at these labs include cell and module testing to establish performance levels and durability; semiconductor materials characterization and analysis in close collaboration with industrial clients that allows industry to understand and improve materials and devices; in-depth R&D on 'show-stoppers' and other critical issues that can be well-examined at a centralized location; fundamental R&D that opens new horizons for PV development; health, safety, and environmental analysis to support the industrial groups contemplating manufacturing; basic PV systems research; solar resource characterization; and program-related work like technical program management, analysis of the economics and potential of PV, information services, and administrative support.

Until recently, the core program represented the entire PV program. This was true during the period of about 1985-1990. Prior to that, when funding was much larger (up to $150 million in 1980), other programs and demonstrations had been supported. These were lost during the cutbacks of the early 1980s. The two aspects of this supplemental part of the program that are important to the future of PV are:

- Manufacturing R&D
- Demonstrations.

Both of these represent added benefits not part of the core program. By manufacturing R&D, we mean R&D at the pilot production level that helps take important PV module technologies from the prototype level to fully optimized, low-cost production. This is a big, resource-intensive step, and one with great risk to industry. Scaling-up to significant production volume is essential to bringing down the cost of PV. Without DOE support, manufacturers would be risking major amounts of capital on scaling-up a new technology. At the same time, the potential market for such larger production would not be assured. To ameliorate this significant risk, and in order to support the cost reductions implicit in enhanced production levels, DOE has embarked (FY 1990) on a PV manufacturing initiative. This fills a gap in the program, since it allows us to take the prototype module technologies developed by the core program and advance them to successful, low-cost production. The key task in such an effort is to fully investigate and optimize individual process steps in module manufacture.

The second major area that has the potential to contribute is demonstrations. During the last few years, a small-scale project called PVU.S.A has begun. It is a collaboration between utilities and DOE to purchase small (20 kW), leading-edge PV modules for PV systems. PVU.S.A. has made contributions by helping us debug and validate new PV module technologies; by advancing the state of the art in systems design; and by fostering contact with various utilities that are potential users of PV. This small-scale project has been well worth the investment, even at a time (late 1980s) when budget dollars for R&D were scarce.

On the other extreme of PV demonstrations, some have proposed a market-pull strategy for affecting the cost of PV. Such a strategy would cost significantly more than the rest of the PV program combined. It would also suffer from the risk of whether it might suddenly be curtailed. When market-pull programs are stopped suddenly (a real risk in a government program), the industry spawned by such a program is endangered. Thus any market-pull strategy would have to address the government's likely commitment. In addition, it should attempt to make the demonstrations as relevant as possible so that they naturally lead to real, cost-effective applications as subsidies are removed. Peak-shaving and export for village power in developing countries are examples of good markets towards which PV should evolve. Finally, any such program must insure against freezing the technology by stimulating purchases of last-year's technology. To prevent this, a schedule of purchase sizes and prices should be published in advance, with declining subsidies. By the end of the program, subsidies would diminish to zero. A well-designed market-pull strategy could be a good way to accelerate PV cost reductions, but it should only come after the core and manufacturing R&D programs are fully funded (more than twice their current levels); it will cost significantly more than existing programs; and it must only be done in a well-designed, well-thought-out manner. Otherwise the expenditures for market-pull could be a tremendous drain on public support for PV.

There are also smaller, but still important 'new' programs that could contribute. For instance, PV is quite dependent on storage for success on a very large scale. Work in PV/storage options could be valuable. Similarly, PV is capable of contributing to the transportation sector by producing hydrogen fuel by electrolysis or simply by providing electricity to battery-powered vehicles. These possibilities merit attention in an expanded program.

On the other hand, if funding is not enhanced over the Base Case (i.e., $35 million/year), the core program will remain subcritical and some advanced technologies will suffer and perhaps fail; no manufacturing initiative would occur and many companies would fail at the critical juncture of true scale-up to manufacture; and the industry would remain without supporting markets to ameliorate risks. We have observed in the recent past that key PV companies have been seriously vulnerable to foreign takeover just when they are nearing the capability of making a large manufacturing presence. U.S. high-risk capital is in short supply. Foreign companies seem better able to take the risks of PV scale-up and developing new markets. In some cases, foreign companies have provided the capital for scale-up of U.S. PV technologies, but the U.S. has lost ownership of these same critical options. The recent sale of the world's largest PV company, ARCO Solar, to Siemens, is a perfect example of this vulnerability. The U.S. lost not only the leading producer of PV modules, but arguably the world's technical leader in innovative next-generation PV options. If the PV budget is not enhanced, our greatest downside risk is the almost immediate loss of U.S. leadership in PV to foreign domination. PV will succeed. But, like so many other high-tech goods, we will be buying it from abroad rather than profiting from it ourselves.

On the other hand, enhanced U.S. funding for PV R&D could strongly impact the evolution of this technology. PV is far more mature now than it was in the late 1970s when government stimulation was first applied. A variety of good technical options exist for making rapid progress toward lower cost. The U.S. industry is poised to make this progress, but a lot depends on the resources available for them to do so. Using public funds to leverage this opportunity could revolutionize the contribution of PV to our nation's energy and environmental future.

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Section 6

TECHNOLOGY EVOLUTION RATIONALE FOR SOLAR THERMAL TECHNOLOGY

October 5, 1990

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RATIONALE FOR
SOLAR THERMAL ELECTRIC TECHNOLOGY

PREFACE

Most experts agree that a mixture of energy alternatives must be developed for the future. As part of a balanced national energy strategy, the widespread use of solar thermal energy systems could increase domestic energy supplies, reduce dependence on imported oil, help U.S. industry respond to increasing international competition for domestic and overseas markets for solar energy systems, and improve the environment by reducing power plant emissions including SO_x, NO_x, and greenhouse gases.

This paper supports solar thermal electric technology energy cost and performance projections for the National Energy Strategy. This document provides a review of the basic principles of solar thermal electric and energy conversion, and the previous contributions of the National Solar Thermal Systems Programs. The market status for solar thermal electric technology, which identifies user requirements to help establish the future technology path and the historical role of the solar thermal electric industry, is discussed. In addition future trends in the performance and cost of the technology, based on input from government laboratories and industry experts, is given. There are two scenarios used for the projections: a base case where the current trends in technology development and the industry continue in a business-as-usual sense, and an accelerated R&D case where the pace and scope of the federal program is modestly increased, but where the technology can be introduced into the marketplace more quickly. The Solar Thermal industry submitted detailed Solar Thermal Electric Power Systems (STEPS) initiatives to DOE. The STEPS initiatives summarize industry's development requirements and possible joint-ventures in the development of competitive solar thermal technology and how to achieve their market penetration strategy targets. The rationale for solar thermal technology development efforts for both base case and accelerated case scenarios strongly correlates with the STEPS initiatives and verifies the program's match with the industry's needs.

1.0 INTRODUCTION

Solar thermal systems are capable of contributing significantly to the energy security, economic competitiveness, and environmental well-being of the nation. The Solar Thermal Systems program is focusing on the development of innovative and economical systems to concentrate and convert solar energy to electricity. This energy source is vast and strategically secure. Its impact upon the environment is minimal. The major impact is land use at less than 15 acres/MWe which is below the total impact incurred for electricity generation by coal. In addition, solar thermal systems can be built quickly and in modular units to respond to immediate market needs and to future energy demands. While some solar thermal systems generate heat for industrial processes, the applications closest to the marketplace generate electricity. R&D tasks, leveraged by cost-sharing with industrial partners, are designed to achieve improvements in the most promising concepts, and to quickly lead to commercial products.

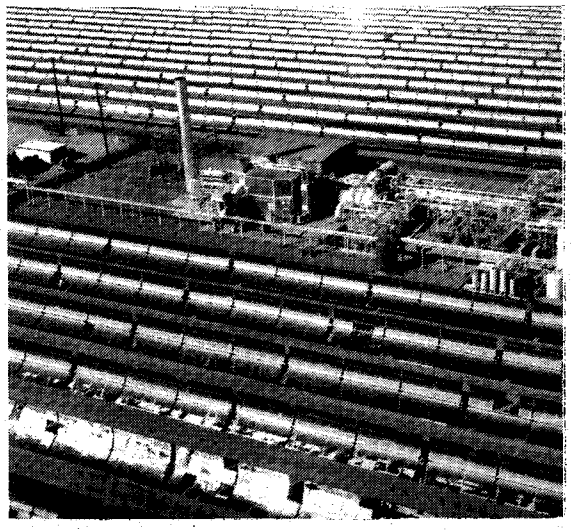
The Solar Thermal industry has been instrumental in providing timely inputs to the federal Solar Thermal R&D program strategy. The Solar Thermal industry submitted detailed Solar Thermal Electric Power Systems (STEPS) initiatives to DOE. The STEPS initiatives summarize industry's requirements and possible joint-ventures in the development of competitive solar thermal technology and how to achieve their market penetration strategy targets. The rationale for solar thermal technology development efforts for both base case and accelerated case scenarios correlate strongly with the STEPS initiatives and verify the program's match with industry needs that are discussed in later parts of this document.

1.1 Technology Description and Applications

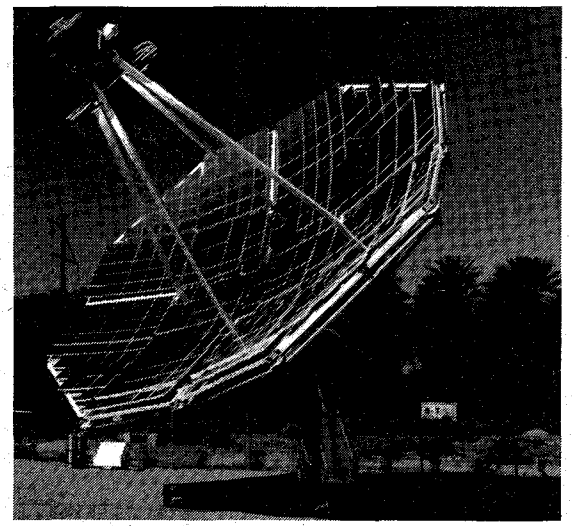
Concentrated sunlight is a versatile and high-quality form of energy that can contribute significantly in meeting our energy needs. The concept for using concentrated sunlight to generate electricity by thermodynamic processes is well documented. Reflective surfaces, which may take the form of parabolic troughs, parabolic dishes, or heliostats, concentrate incident sunlight onto a receiver where it is absorbed into a working fluid that powers a thermal conversion-generator device. Solar thermal systems, operating either with storage or in a hybrid mode with an auxiliary fuel, offer significant potential as added capacity to meet utility peaking or intermediate/baseload electric power generation needs.

The three primary optical concepts used in solar thermal technology are line-focus parabolic troughs, point-focus central receivers, and point-focus parabolic dishes. Figure 1 shows concept and schematic diagrams and actual installations. All three concepts use the same principle of concentrating sunlight but are distinguished by various mirror geometries and receivers. These systems can provide concentrated sunlight for electric power and industrial process heat applications.

Parabolic troughs use a single axis tracking collector that concentrates sunlight onto a receiver tube positioned at the focal line of each trough. Concentration ratios of more than 100 times are typically used to generate temperatures near 400°C. Troughs are modular and can be grouped together to produce large amounts of heated fluid, which is then transported to a nearby central facility to generate electricity. Because of the R&D efforts in the early

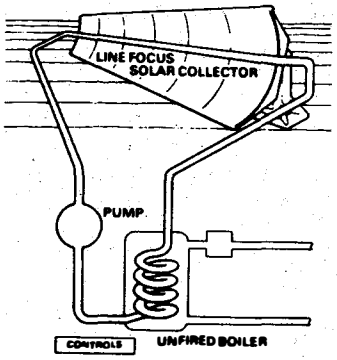


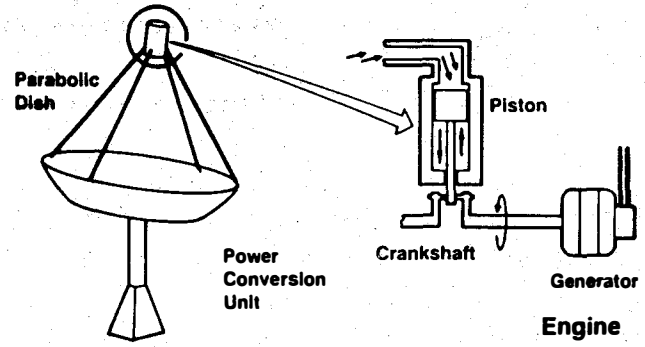
LUZ SEGS PARABOLIC TROUGH PROJECT



ADVANCO'S VANGUARD DISH/STIRLING MODULE

SOLAR ONE CENTRAL RECEIVER PROJECT





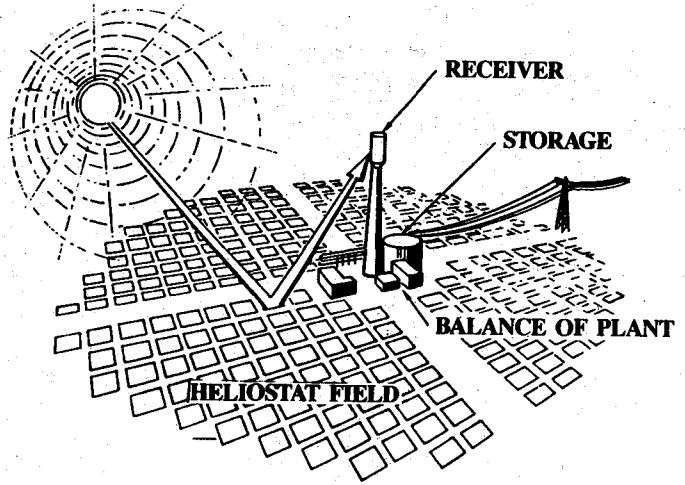


Figure 1. Solar Thermal Technologies

years of the Solar Thermal Program and the solar industry and lower technology development requirements, troughs are the most mature current solar thermal technology which is commercially available.

The commercial success of the Solar Electric Generating Systems (SEGS) hybrid solar and natural gas fired steam electric generation plants generating over 274 MWe in California has provided the impetus for continued private sector development of the trough technology. Use of natural gas as a backup is necessary to meet capacity/load requirements because no economical storage system presently exists for the temperature conditions of these systems. Luz International is in the early development stages of its fourth generation trough collectors (LS-4), which will be capable of direct steam generation in the receiver tube, eliminating the need for oil heat transfer fluids and the oil-to-water heat exchanger. This new generation of collector is projected to be available in the mid-1990s. Development of low cost thermal storage could also lead to reduced dependence on the gas-fired operating mode of the hybrid configuration, to meet warranted output power delivery requirements. Industrial Solar Technology (IST) and other trough system developers continue to improve products for the industrial process heat market.

Central Receiver systems use fields of two-axis tracking mirrors known as heliostats to reflect the sunlight onto a single, tower-mounted receiver. Single heliostats have been built in various sizes ranging from 40 m^2 to 200 m^2. Higher receiver efficiency, two-axis tracking lower cost heliostats and use of thermal storage systems make central receivers a more attractive long-run candidate for electric power generation than less efficient trough collectors. In addition, nitrate salt as the heat transfer and storage fluid can allow for greater efficiency during operation from storage and allow for higher capacity factors, resulting in lower overall costs of energy. These advantages and a number of on-going technology improvements are expected to make the central receiver systems cost effective alternatives in the long-term for utility power production in the 100 to 200 MW capacity range.

Parabolic dishes use two-axis tracking and focus the sunlight onto receivers located at the focal point of each dish. Heat engine/electric generators coupled to the receiver convert solar heat to electricity. Each dish module is a stand-alone unit and generates 60 cycle, 240 volts, single-phase power that can be directly fed to a grid. Dish modules can be used in stand-alone or large multi-module systems. An example of a stand-alone unit is a single 25 kWe dish module with peak solar to electric conversion efficiency approaching 30%. Higher concentration capability, modularity, and improvements in heat engine and receiver subsystems will make this technology one of the most efficient solar electric conversion processes for near-term niche markets and ultimately utility/industrial power markets.

Low maintenance costs, high reliability, and reduced risks will be critical factors in the acceptance of dish engine technology in the remote or off-grid applications and as the technological "stepping-stone" for cost-effective systems for utility applications.

1.2 Resource

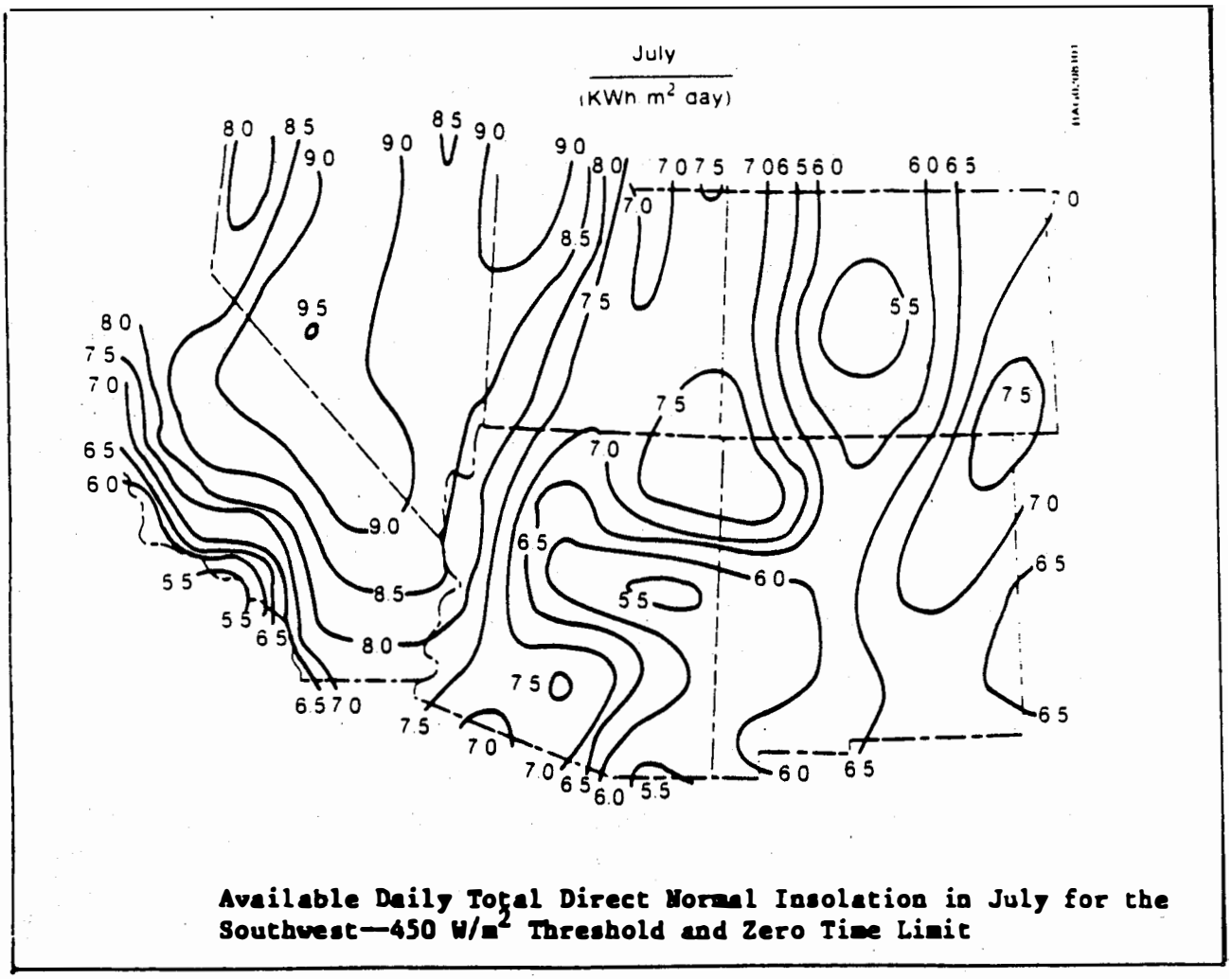
The solar energy resource is the highest in the southwest U.S. and is significant throughout the western U.S. Solar energy falling on the United States each year is more than 500 times as much energy as the nation annually uses. All concentrating systems have their best annual output in regions where direct insolation is highest (e.g., the southwestern United States and other semiarid regions of the world), but they also can be utilized, at slightly higher cost, in other regions with somewhat lower levels of direct insolation. Solar thermal systems take advantage of an enormous energy resource; a recent report estimates that solar insolation accounts for more than 87% of the total accessible U.S. energy resource base.

Annual average direct insolation in the Southwest U.S is shown in the Figure 2 and can be measured in MJ/m^2 or kWh/m^2. Using this map, a rough interpolation for Barstow, CA would result in an insolation value of about 8.5 kWh/m^2 - day for July while the measured average value during 1976-79 at the same site was 7.5 kWh/m^2 - day. Experience at the Barstow Solar One Project has illustrated the variability in solar insolation occurring from year to year. Using Barstow Solar One insolation of 7.5 kWh/m^2 - day as an example, solar thermal technology systems including central receivers, dishes, and troughs could be installed/sited for utility or industry power applications in federal regions 6 through 10 as defined in the Renewable Energy Technology characterization (and as shown in Figure 2).

1.3 Industry Status

The U.S. solar thermal technology industry has experienced considerable consolidation over the past decade. Currently there is one major and one smaller company producing solar thermal systems domestically, and about five others involved in R&D of near- and mid-term advanced system components. Only one company (Luz International Ltd.) has had sales in the utility-scale electric systems market, and only a few others (such as Industrial Solar Technology) are currently in the commercial small scale industrial cogeneration and process heat/hot water market. These companies are using parabolic trough technology. The remaining companies involved in component R&D are focussed on cost reduction, improved reliability and increased efficiency of various system components to make solar thermal electric systems competitive with conventional fossil fuel based utility systems.

Currently, Luz International Ltd. has 274 MWe of privately funded, parabolic trough electric generating capacity operating on the Southern California Edison utility grid. In addition, 80 MWe is currently in construction, and under current contracts, they plan to add an



Available Daily Total Direct Normal Insolation in July for the Southwest—450 W/m^2 Threshold and Zero Time Limit

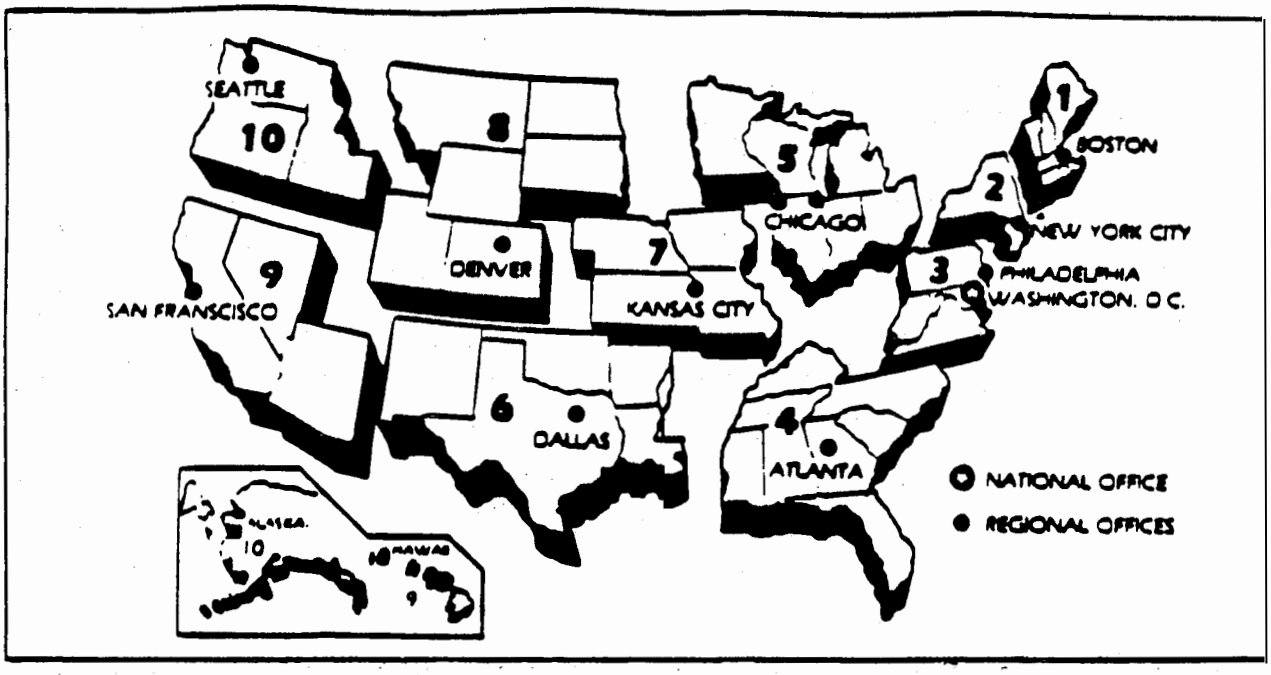


Figure 2. Solar Energy Resource & Federal Regions Applicability

additional 320 MWe by 1994, with long-term plans to install 80 MWe/year through the year 2000. Solar Thermal electricity capacity growth and annual installations of capacity are shown in figures 3 and 4, respectively. These trough systems operate in a hybrid mode using natural gas and collectively account for more than 95% of the world's solar electric capacity. The cost of these systems has fallen steadily from 24¢/kWh for the first 14-MWe system (1984) to below 10¢/kWh for the 80 MWe plant installed in 1989, according to Luz's economic assumptions[1]. Luz is now working on improving the trough technology by developing an "in-situ" steam boiling technology with water as the heat transfer fluid to replace oil. This is planned for the LS-4 collector, a fourth generation trough module. Both technical as well as system installation/O&M improvements will bring the Luz system installation cost to $1850-2100/kW. Company officials estimate that these further system cost reductions will make this technology cost-effective in the worldwide electric marketplace.

Industry's success in using tax credits and avoided cost standard offers has shown that, in the near term, the solar trough/gas hybrid approach is the most marketable. However, industry and utility studies show that the central receiver and dish electric technologies have greater potential for achieving more cost-competitive generation in the mid and longer term, as discussed later in this chapter.

1.4 Market Acceptance and Experience

The domestic utility market holds major long-term opportunities for large-scale application of solar thermal systems. In this market, one of the largest potential applications for solar energy is for generating electricity during daytime summer peak load periods. Currently, most utilities use, and are planning to add, fossil-fuel-fired generators to meet these demands. Solar electric plants, which produce energy during daylight hours, represent an environmentally benign means of meeting peak electrical demands. Being a clean source of power may become a critical characteristic, since environmental regulations (and the related costs) are projected to grow, as evidenced by both the proposed Clean Air Act amendments and various state regulations (such as in California).

Building on the experiences of a decade of DOE and industry sponsored research, the parabolic trough systems installed to generate nearly 274 MWe in California are a prime example of applying past research to today's needs. Since these Luz plants have no thermal energy storage systems, they rely on natural gas heaters to supply steam to the turbines during non-sunny periods. Under the Public Utility Regulatory Policies Act (PURPA), these plants are allowed to obtain 25% of their annual energy input from fossil energy. Use of natural gas heaters assures a capacity credit and an improved benefit/cost ratio for the plant

[1] Luz's economic assumptions include capacity credits and also differ from those utilized for the analysis in this document. Therefore, the values are not directly comparable.

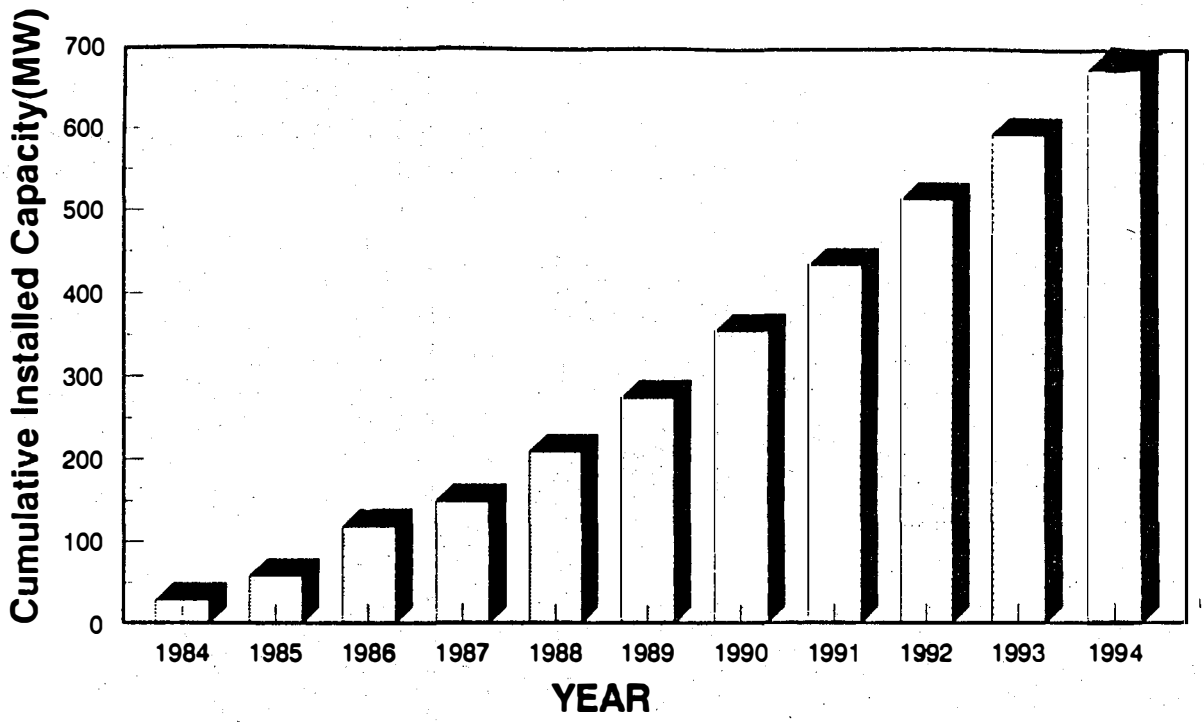


Figure 3. Solar Thermal Electric Installations in the U.S.

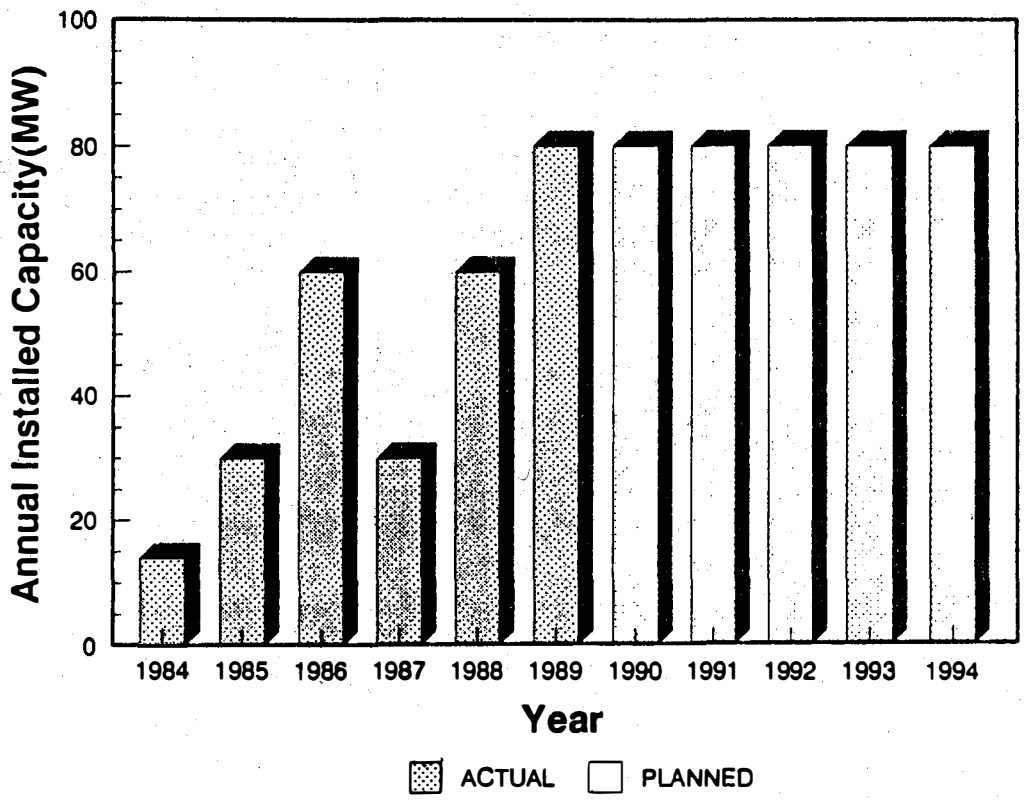


Figure 4. U.S. Annual Installed Solar Thermal Electric Capacity

since power is delivered to the grid during peak and mid-peak periods. Luz plants have demonstrated that mature SEGS plants can achieve energy predictions. This is demonstrated by the SEGS III-V data presented in Figure 5.

Planned additions to these solar thermal Luz power plants has brought the total electric generation to the equivalent of about 0.01 quad/year in 1990 which is equivalent to approximately 822 million kWh of electricity or 0.484 million barrels of oil equivalent. Further improvements and additions to the trough systems, coupled with the implementation of the higher efficiency dish electric system, are projected to bring the total solar thermal contributions to about 0.04 quad/year, or about 3288 kWh of electricity or 1.94 million barrels of oil in the Western region of the U.S. by 2000.

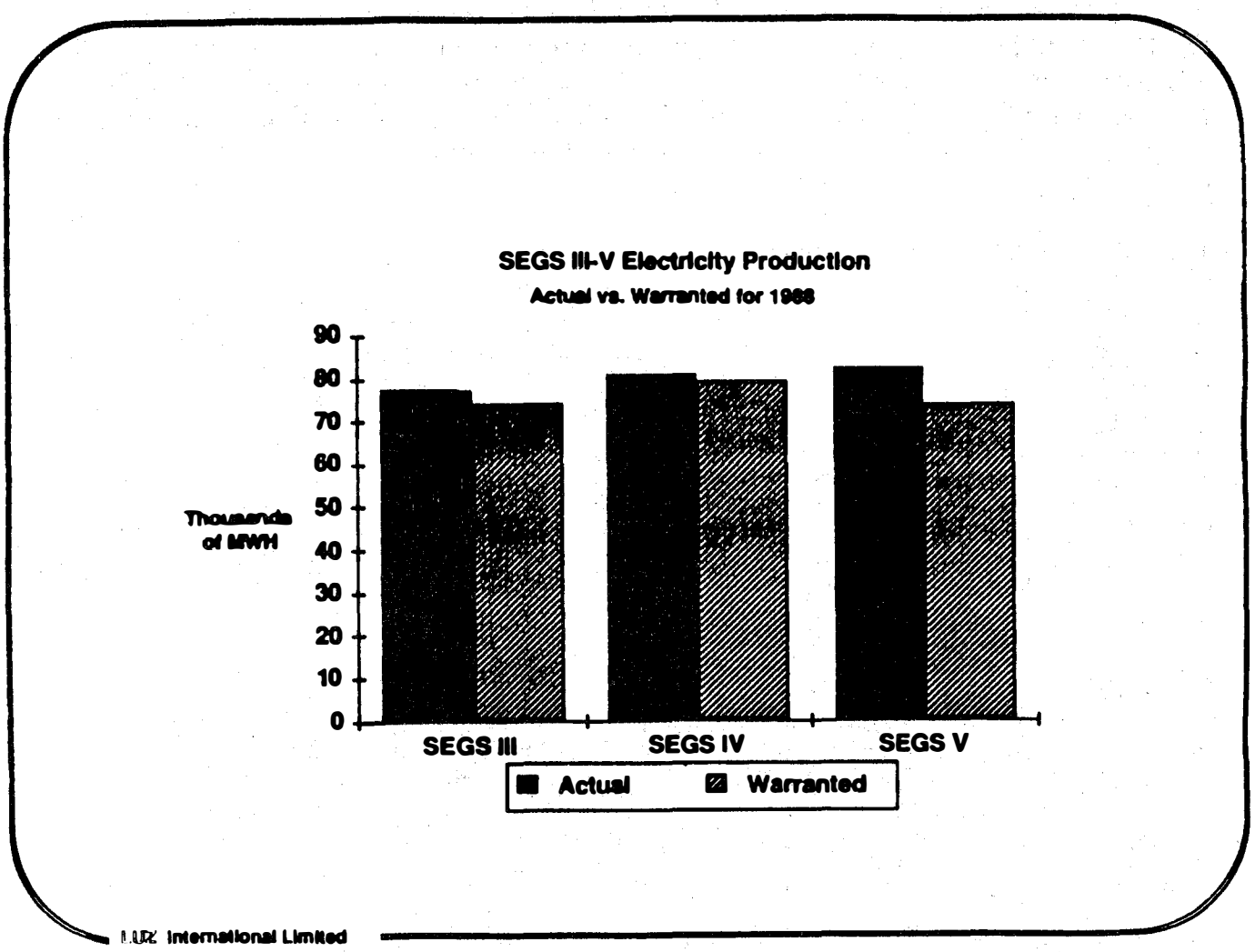


Figure 5. Reliability: Actual SEGS Performance Exceeds Warranted Levels

In the past 8 years, all solar thermal technology types have been demonstrated in industrial-like settings. A 10-MWe experimental central receiver pilot plant (Solar One) was deployed by a joint government-industry team and operated successfully by Southern California Edison on its grid for 6 years, thus achieving the objectives of the experiment. While annual system efficiency for this plant (7.4%) was somewhat below initial predictions for the water/steam receiver and steam to oil storage, extensive operational experience was gained and the plant delivered more than 37,000 MWh to the grid. Loss of steam production during cloud transients, steam-to-storage, and steam-from-storage were shown to be inefficient and resulted in the low annual system efficiency. Based on the 1988 utility central receiver studies by Pacific Gas & Electric, which used the prototype data from the advanced heliostat and the efficient nitrate salt receiver and storage technologies and improved operational procedures learned from the pilot plant experiences, annual system efficiencies of 14% to 15% with below 11¢/kWh have been projected for a 100 MWe plant built today.

Prototype parabolic dish electric systems using central steam turbine conversion systems, totaling about 5 MWe, have also been operated in utility settings in southern California and Georgia. More recent development of a dish mounted engine/generator concept by Advanco and McDonnell Douglas has led to significant increases in system performance compared with the earlier designs, which collect the heat as thermal energy and transported it to a central location for electric generation. Dish/Stirling engine-generator modules set on-grid records of 29% overall system net conversion efficiency of sunlight to electricity.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

Several figures of merit have been used to characterize the progress of solar thermal central receiver, dish/Stirling, and parabolic trough technology. Probably the most often cited figure of merit is the levelized cost of electricity, or COE in units of $/kWh. COE captures initial capital cost and annual O&M costs during the life of the solar thermal system. Though convenient and widely used, COE does not capture the value derived from the assured production of energy by power plants at times of greatest and therefore most valued demand (peak demand). This ability is especially true for a central receiver facility with large storage and for parabolic dish and trough hybrid systems using fossil fuel backup. The ability to serve peak demand is valuable because it replaces typically high-cost energy. A value to cost ratio (or benefit/cost ratio) has been discussed in the utility industry as possibly a more appropriate figure of merit for these systems, but is not presented here. The key figures of merit used in this report to characterize overall systems cost is COE, and to characterize initial capital cost is $/kW as a function of capacity factor.

- Levelized Cost of Electricity ($/kWh)

  The basic figure of merit we use to judge the economic potential of each of the technologies is the levelized cost of electricity (COE). This figure of merit is convenient to use since a detailed calculation of the value of the electricity as a function of time throughout the day is not required. Since the time-dependent electricity value varies from utility to utility, such a detailed calculation is beyond the scope of this document. Though it is convenient, it should be understood that COE does not give credit to the fact that solar thermal power plants typically supply power during the peak electricity demand period for the utility. This is especially true for a central receiver plant with a large energy storage system or a fossil-hybrid plant employing parabolic dishes or troughs. Consequently, solar thermal systems can achieve capacity credits which significantly increase the value of the electricity produced.

- Capacity Factor (%)

  The capacity factor is the amount of energy that the system produces as a percentage of the total amount of energy that it would produce if it operated at rated capacity during the entire year. This figure can be used to calculate annual energy production using a similar method as for other technologies. Capacity Factor of a given power plant in a utility system is determined by many factors including plant and load characteristics and dispatch strategy. A higher capacity factor, as used here, simply indicates the ability to meet the load for a greater proportion of the year, assuming that plant power is dispatched as fully as possible.

- Installed cost per unit of design capacity ($/kW)

  Solar Thermal systems include central receiver systems, dish systems, and trough systems. These systems are of different sizes relative to each other and each system

is composed of different major components. To compare such systems against one another and to other energy systems, cost-per-unit kW is used as a figure of merit to place these systems on a somewhat consistent basis.

- System average annual efficiency (%)

  The system average annual efficiency is the percentage of energy extracted from the sun and converted into electricity. It is a good technical measure to use in tracking performance trends.

- Installed cost per unit of actual output ($/kWh/yr)

  This figure of merit combines both cost and performance measures. It is a figure of merit often used by financial institutions. It does not include assumptions concerning choice of financial parameters and the time-value of money.

- Operation and maintenance cost (cents/kWh)

  O&M accounts for all costs incurred for operation and maintenance of the solar plant facility, including labor, parts, and materials.

2.2 Historical Technology Trends/Current Status

Significant progress has been made toward generating economically competitive solar thermal energy for electrical applications. Research and development (R&D) efforts in the past years have improved the performance and the reliability of solar thermal systems and reduced both the capital installed costs ($/kW) and energy costs ($/kWh) of solar thermal systems to one-fifth the cost of early systems. This large reduction is a result of lower cost components and increased system efficiency. However, further cost reductions are required to make solar thermal energy cost-competitive with energy generated by fossil fuels.

Concentrators are the single highest cost element of any solar thermal system, accounting for 30-50% of the total system cost. Thus, significant R&D efforts have centered on bringing down the cost of concentrators while improving optical performance and durability. In order to monitor progress, concentrator component costs are indicated in terms of cost per area of the concentrator ($/m^2). Over the last decade, costs of heliostats (Figure 6) and dishes (Figure 7) have dropped by a factor of five. Luz has also shown significant cost reductions in trough concentrators through both generational R&D improvements and economies of scale (Figure 8).

Receivers (central receivers) and receiver/engine/generator units (dish/Stirling engine) are also key solar thermal components, having significant impacts on the overall system cost and efficiency. As with concentrators, receivers have seen sizable cost reductions (Figure 9) over the last decade, starting with the tube receivers costing approximately $200/m^2 at Solar One and Shenandoah, to today's nitrate salt (central receiver) and reflux (dish) receivers below $30/m^2. Early dish systems such as Shenandoah and Solarplant 1 utilized a centrally-located heat engine (steam turbine), which received thermal input from the concentrator field through the use of a piped heat transfer fluid. These systems were limited to approximately

17% net system efficiency. Later systems, such as the Advanco and McDonnell Douglas dish/Stirling modules, demonstrated the higher efficiency (41%) of Stirling engines and achieved a world record 29% net solar-to-electric system conversion efficiency.

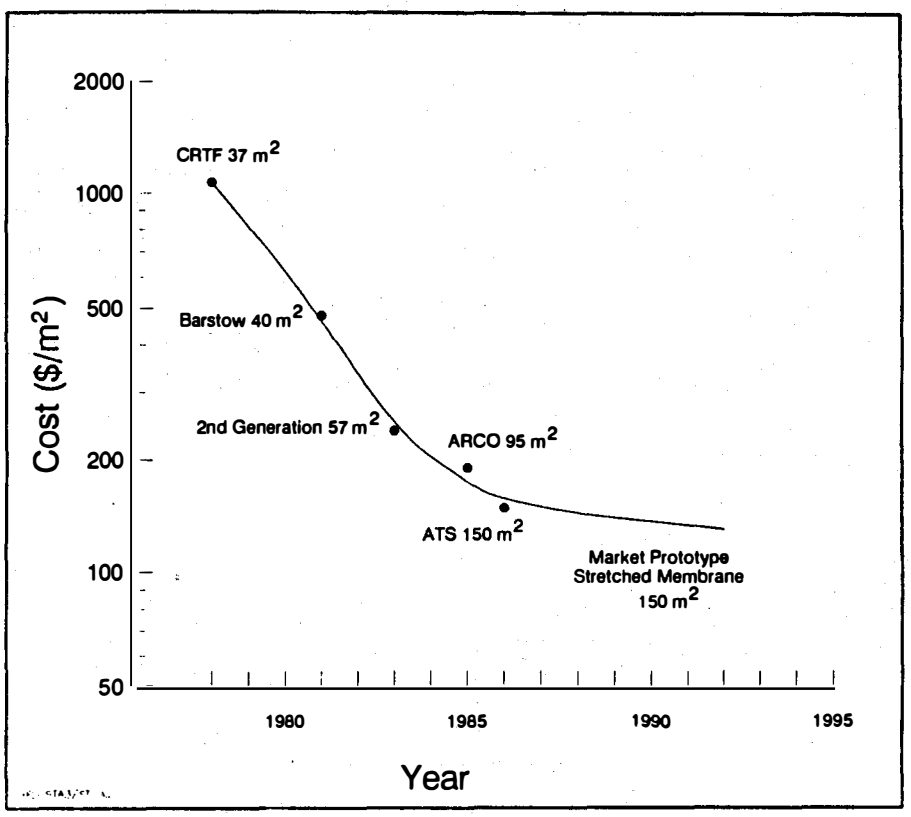


Figure 6. Heliostat

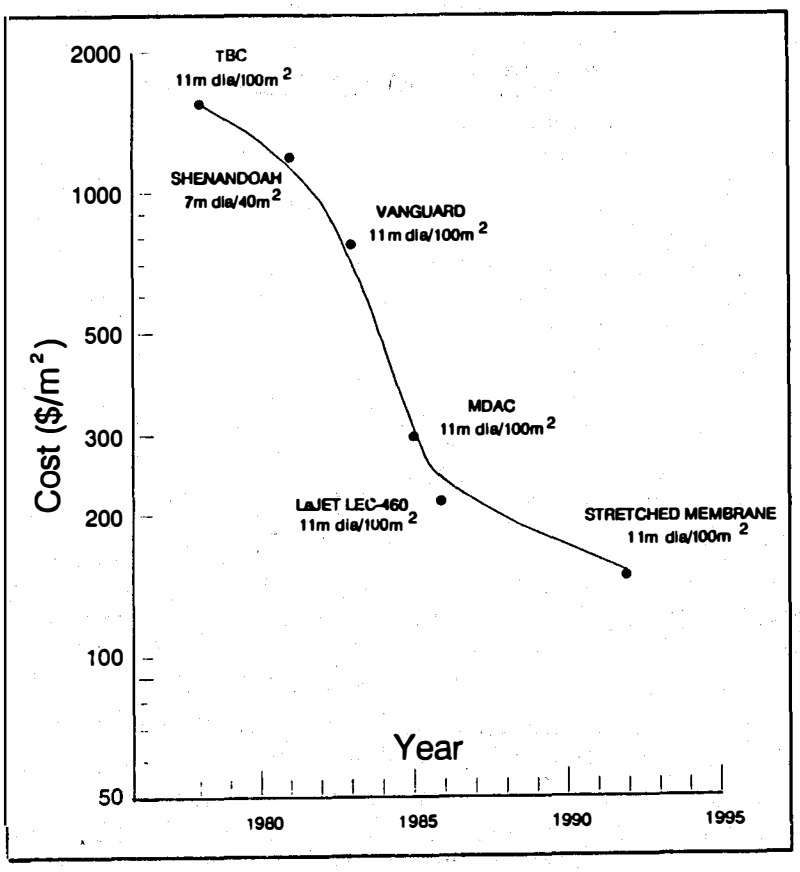


Figure 7. Parabolic Dish

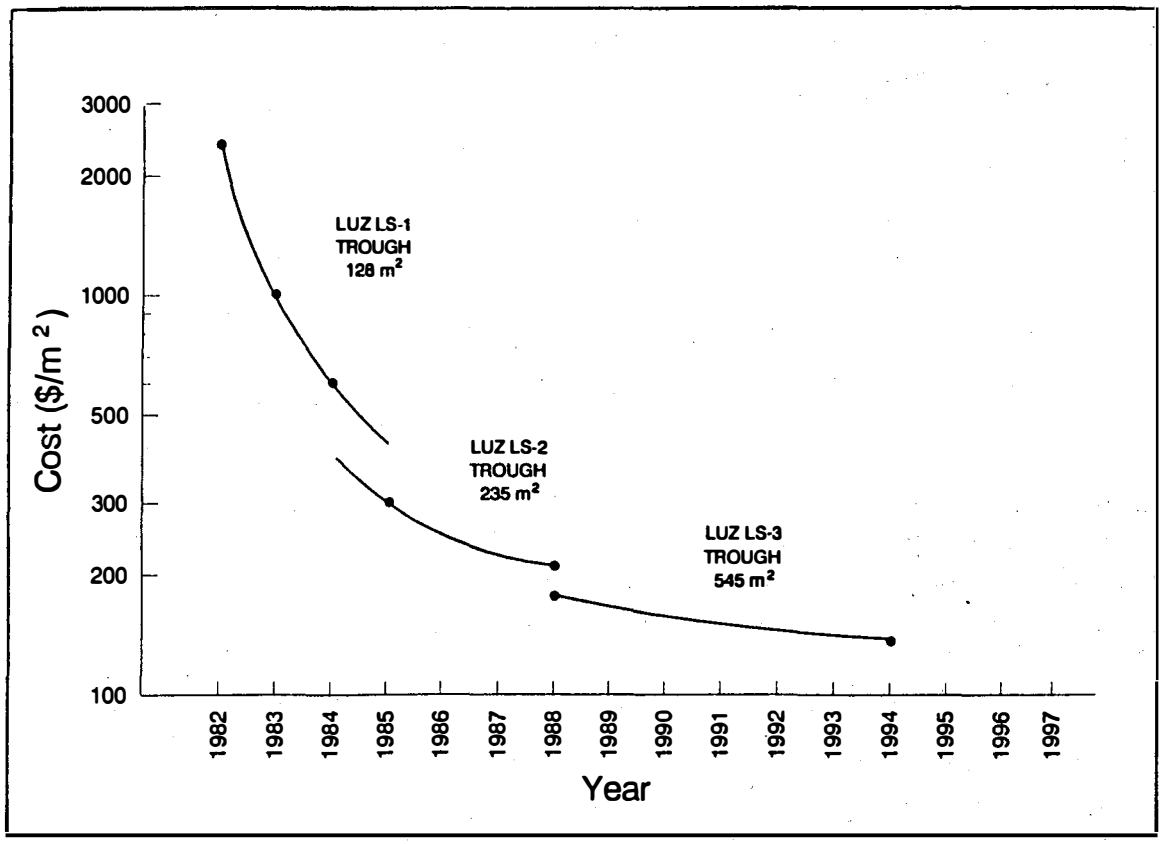


Figure 8. Parabolic Trough

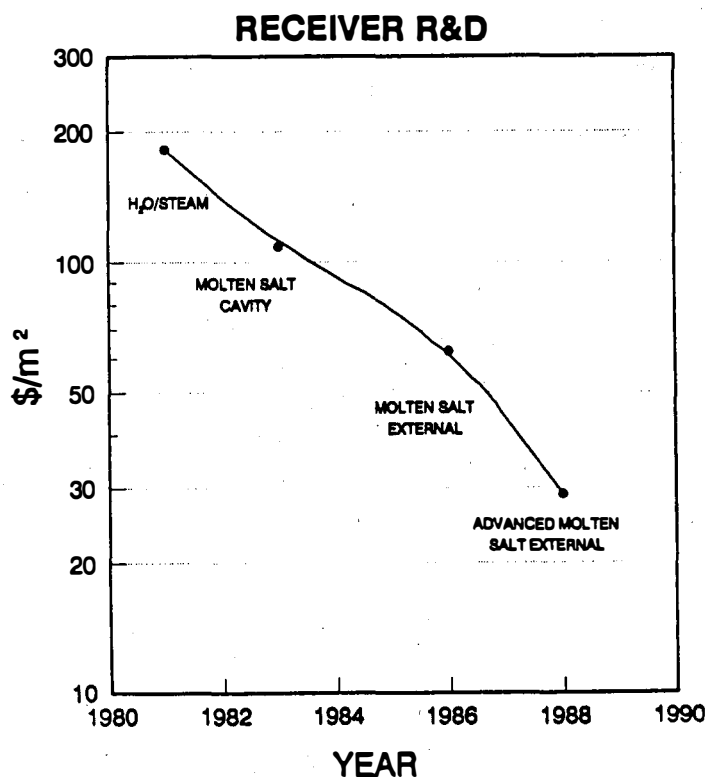


Figure 9. Central Receiver

3.0 COST AND PERFORMANCE PROJECTIONS

In the previous sections, the three solar thermal power plant concepts were described. In this section, the cost and performance improvements of the individual components and their impact on the economics of the total power plant are described.

Cost of Electricity (COE) projections are presented as a function of technology improvement for the three solar technologies. It should be recognized that uncertainty exists in these projections. These uncertainties are in both the expected technical achievements and in the particular time in the future at which they will be realized. In Section 4, the technology advancements that will permit the lowering of the COEs are discussed. These technology advancements are summarized for parabolic troughs, central receivers, and parabolic dishes, respectively.

To arrive at a justifiable rationale for the Solar Thermal Electric Technology and to establish credible scenarios for the solar thermal technology implementation for the National Energy Strategy (NES), a three step process was used. This process, outlined below, led to the establishment of a schedule combined with cost and performance projections for the introduction of Solar Thermal Electric power systems in the utility markets.

- Schedules for baseline and accelerated R&D programs were defined. Development steps remaining for industry to achieve commercially-viable systems were identified in both the base and accelerated solar thermal R&D cases, respectively, and presented in the context of the industry-proposed STEPS process.

- The systems which represented the end-product of each major phase of the R&D effort were characterized (plant capacity, major components, typical application characteristics), and the latest available systems analysis and manufacturing cost studies were used to project the cost and performance of each power plant. From these inputs, the cost of electricity for each plant configuration was projected.

- Estimates for the timing of the introduction of each new or improved plant configuration were then made considering relevant factors including: component/subsystem availability from the R&D pipeline; value of the solar thermal technology relative to the conventional options; degree of risk associated with the financing and construction of each configuration; and degree to which planned cost-sharing by DOE (for each R&D case) would offset a portion of the risk of industry implementation.

A standardized model was utilized to calculate COEs, in order to provide a uniform basis for comparison of technologies. The model used consistent economic assumptions, although it does not take into account any capacity credit payments. Due to their highly variable nature, these actual payments are different from utility to utility, and may also vary based

on various technical factors, thus requiring almost individual evaluation of power purchase contracts. In addition, plant ownership scenarios such as municipal ownership, investor-owned utility ownership, and independent power producer ownership will also affect the overall revenue picture. Increasing environmental regulations will result in greater costs for fossil-fueled plants relative to solar thermal plants which have little or no emissions.

The Base Case scenario is based upon the FY 1990/1991 budget levels. The schedule is shown in Figure 10. The Accelerated R&D case is based upon budget increases to move technologies into the marketplace faster, such as through greater support of STEPS activities. The schedule for this scenario is shown in Figure 11.

Figures 12 and 13 present solar thermal base case and accelerated R&D scenarios utilizing cost of electricity (COE) in cents/kWh to capture both initial capital cost as well as O&M costs during the system life-period. COE projections are presented as a function of time for the three solar technologies. As previously mentioned, uncertainty exists in these projections in both the expected technical achievements and the particular time in the future at which they will be realized. The technology advancements needed to lower the COEs displayed in Figures 12 and 13 for base case and accelerated R&D scenarios are discussed in detail in Section 4 for parabolic trough, central receiver, and parabolic dish technology power systems, respectively.

3.1 Parabolic Trough Power Plants

Luz is currently performing internally funded R&D on a fourth generation of trough collector, the LS-4. The LS-4 is projected to be a significant improvement over the LS-3. Utilization of direct steam generation would eliminate an oil/water heat exchanger. These improvements in efficiency and elimination of hardware are expected to result in significant system cost savings, as well as a 15% collector cost reduction.

Since the Luz system is already commercial, additional R&D funding is not required to help commercialize this technology. R&D funding expended in the 70s and 80s helped Luz in this regard. However, additional R&D funds could be used to improve the efficiency, operations, and cost of the Luz plants.

Advancements in future years for parabolic trough power plants are based on the assumption that larger SEGS plants will be built. Large plants take significant advantages from economies of scale and should be able to achieve a lower COE in coming years.

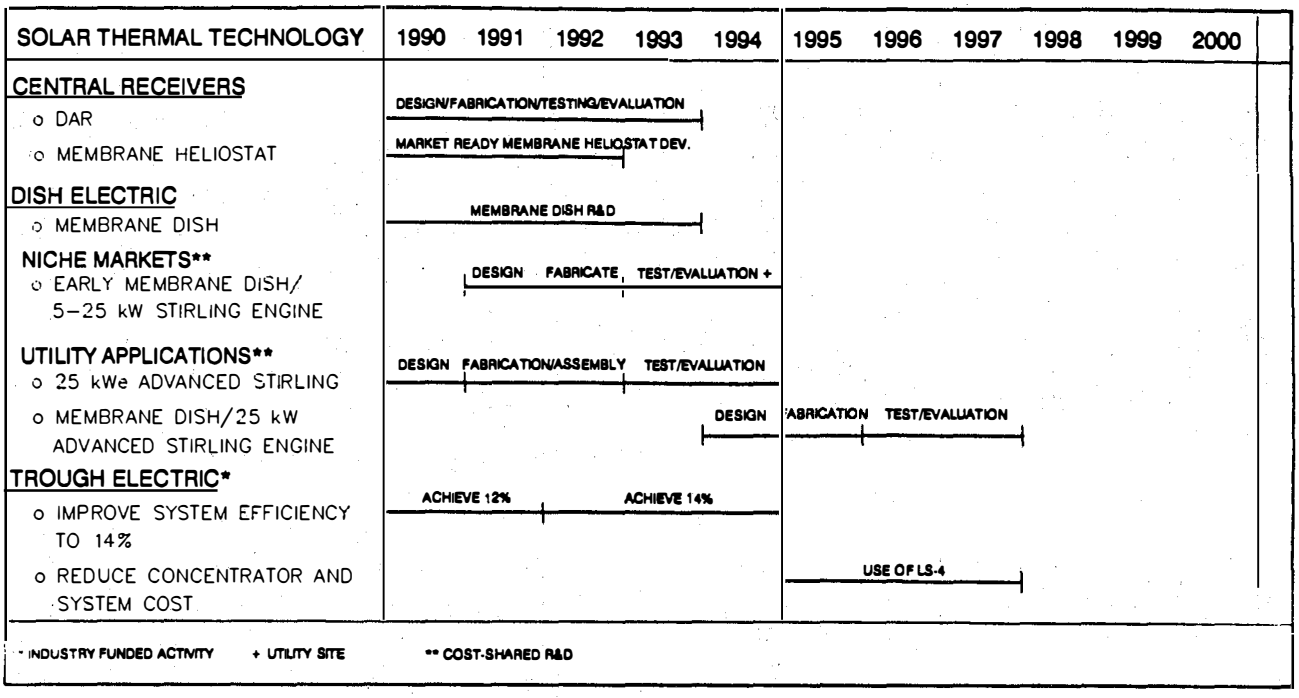


Figure 10. Schedule - Base Case

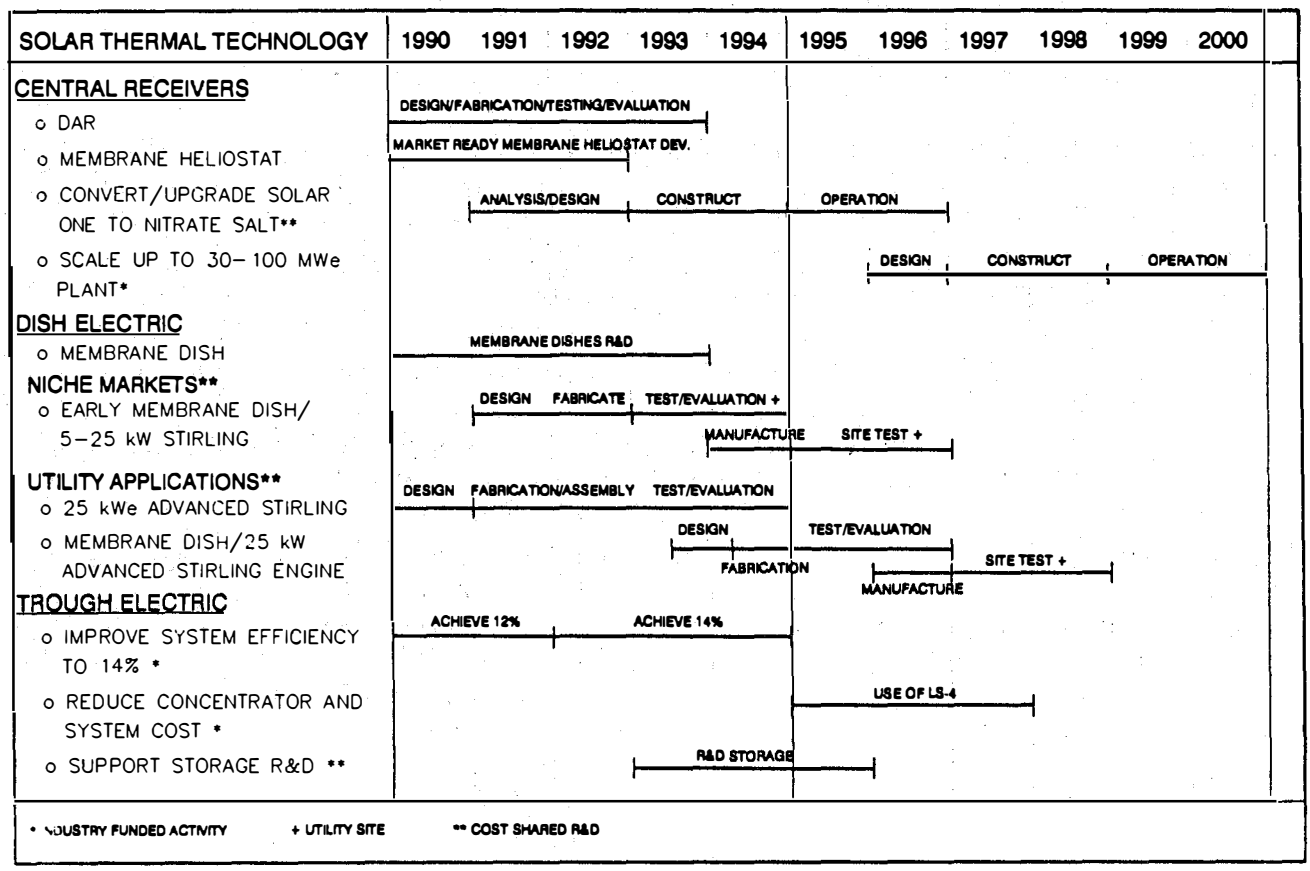
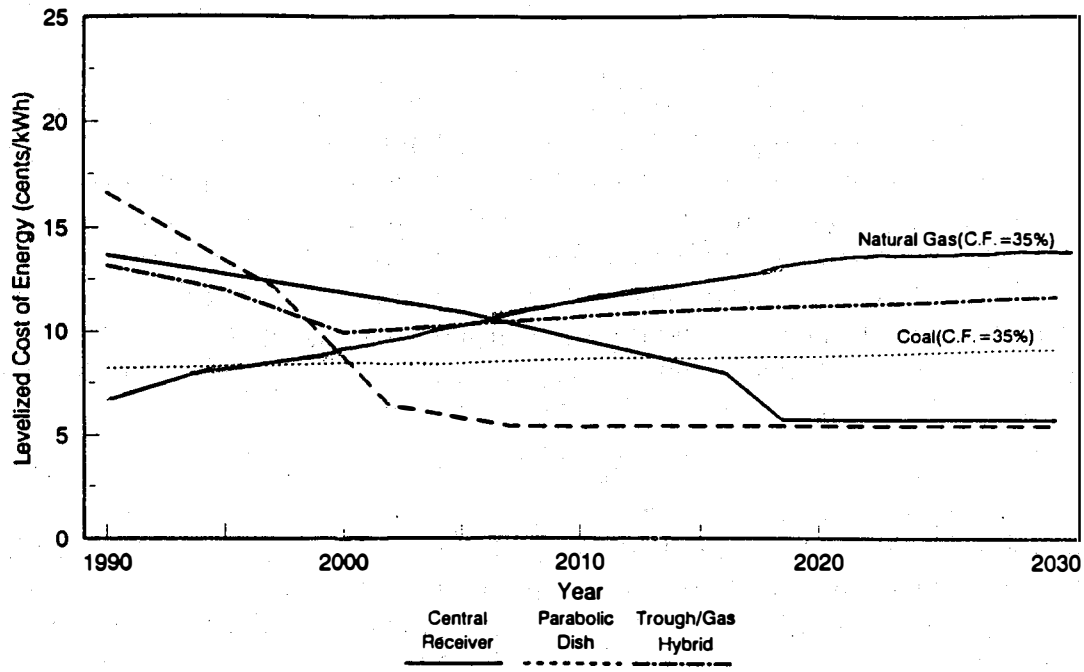
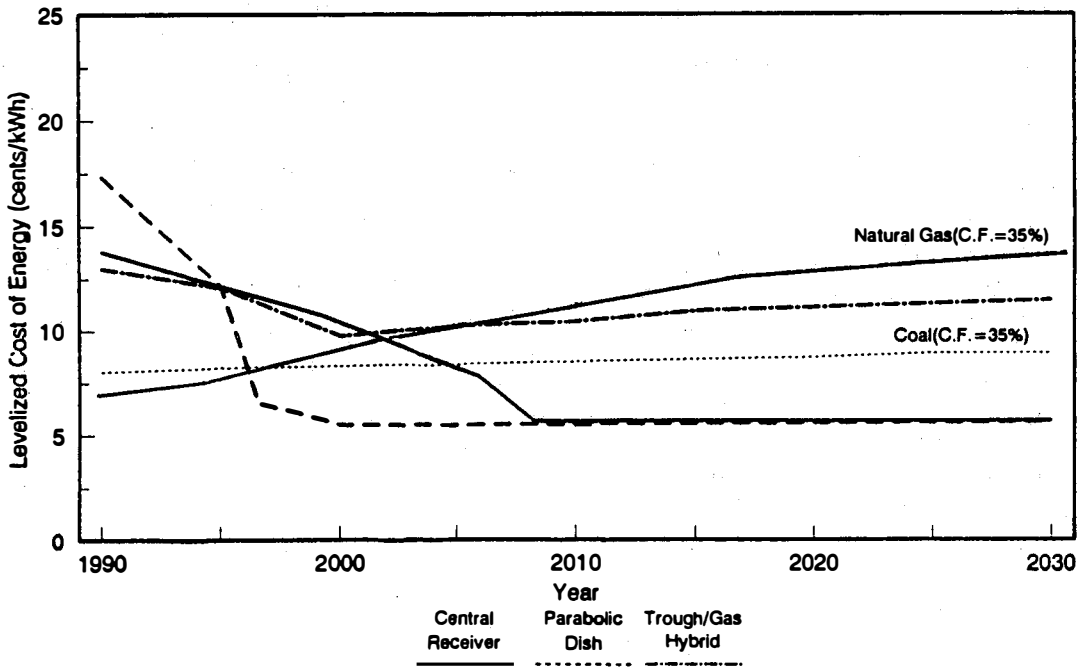


Figure 11. Schedule - Accelerated Case



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 12. Base Case Solar Thermal R&D



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

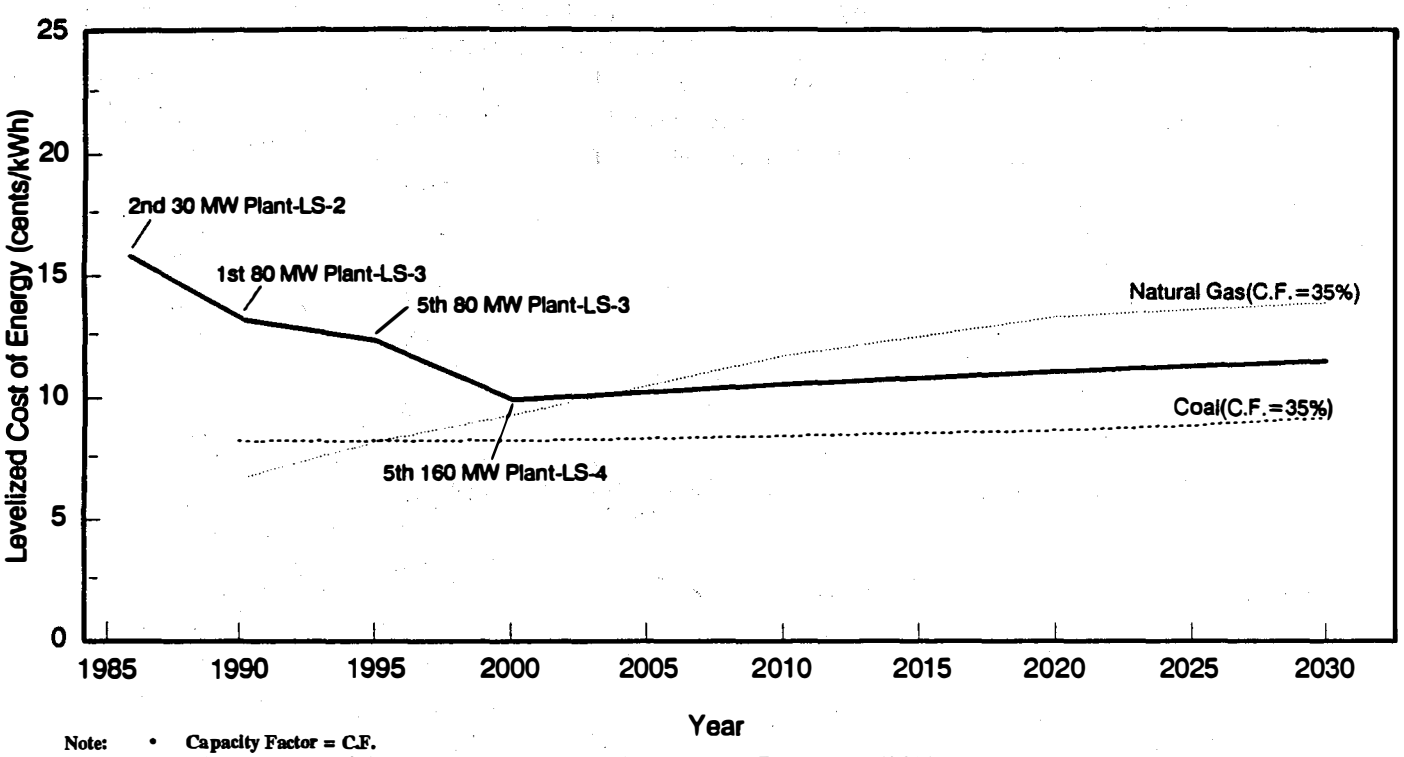
Figure 13. Accelerated Case Solar Thermal R&D

These larger plants will be competitive with the COE for natural gas intermediate plants (Figure 14). Table 1 presents base case as well as accelerated case parabolic trough cost performance projections on component and subsystem basis. In order for the Luz trough system to lower the COE, a cost-effective thermal storage system will have to be developed to eliminate the requirement of natural gas.

The LS-4 system under development utilizes direct steam generation. A cost-effective thermal storage approach for steam systems is not presently defined. Since the Luz system is already being developed to be commercial in 1995, additional funding is not included in the base case. Current concepts for appropriate thermal storage systems are loosely defined and have relatively high technical risk; thus, this may provide an opportunity for a joint DOE/Luz effort as an example in the accelerated case. Thermal storage systems could provide a significant opportunity for technology transfer to or joint R&D with other technology programs.

Table 1. Parabolic Trough Hybrid Cost and Performance Projections

Technology	Second LS-2	First LS-3	Fifth LS-3	Fifth LS-4
Base/Accelerated Case (year)	1986	1990	1995	2000
Plant Capacity (MW)	30	80	80	160
Capital Cost ($/kW)				
Concentrator	$1518	871	647	547
Power Bloc	560	560	560	560
BOS	980	975	960	437
Indirect	612	481	433	309
TOTAL	3670	2887	2600	1853
O&M (mils/kWh/yr)	20.0	16.7	15.0	13.5
Capacity Factor	35.0%	35.0%	35.0%	35.0%
Annual Efficiency	10%	12%	14%	15%
COE (¢/kWh)	15.7	13.0	12.2	9.9



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 14. Parabolic Trough/Hybrid Technology - Levelized Cost of Energy

3.2 Central Receiver Power Plants

Sandia Laboratories has completed the proof-of-concept step for a salt-in-tube central receiver (CR) power plant. All of the major components unique to the molten-salt central receiver power plant have been built and tested, and have demonstrated generally excellent performance. Sandia has tested 4 stretched-membrane heliostats with two market-ready heliostats under development, 3 salt-in-tube receivers, a nitrate salt storage system, a salt/water steam generator, and commercial-scale pumps and valves. Sandia will complete proof-of-concept tests for the direct absorption receiver (DAR) in 1993 upon completion of the Panel Research Experiment.

In order to complete the next step, prototype validation, the receiver needs to be scaled up. Scale-up of the other components listed above is straightforward and additional R&D is not required. Scaling up receivers entails additional risks, especially when the critical dimension, length, must be increased significantly (such as by more than a factor of three). To date, only 3 small-scale receiver panels using molten salt-in-tube technology have been built and tested. Sandia recently completed testing of a 5 MWt receiver panel in 1988. Prototype validation of a nitrate salt receiver in a cylindrical geometry at a reasonable size for future scale up to a 100 MWe plant can best be accomplished at minimum risk by testing it at the existing Solar One site. A nitrate salt receiver in a hybrid Solar One plant would be approximately 60% the height of a 30 MWe receiver (hybrid plant) and 45% the height of a 100 MWe receiver (hybrid plant) with reasonable diameter increase (see Table 2). If the Solar One receiver is sized for operation with storage (non-hybrid), then the receiver height will be closer to 60% of the receiver height in the 100 MWe hybrid plant.

Table 2. CR Receiver Scale-up Requirements

	RECEIVER			
CR PLANT	MWt	HEIGHT	DIAMETER	ABSORBER AREA
10 MWe				
w/Storage	70	9.7 m	9.3 m	282 m^2
Hybrid	40	7.3 m	7.0 m	161 m^2
30 MWe				
w/Storage	192	15.5 m	11.6 m	566 m^2
Hybrid	115	12.0 m	9.0 m	339 m^2
100 MWe				
w/Storage	470	21.0 m	19.0 m	1270 m^2
Hybrid	283	16.4 m	14.9 m	765 m^2

The next step, manufacturing validation, would be performed following the test at Solar One. The purpose of this step is to reduce the perceived risk of the technology. If a near-term commercial-scale plant is built, i.e. 30-100 MWe, and it operates satisfactorily for a number of years, investors and users would feel confident that a 100 MWe commercial plant would be successful (the final step). The 30-100 MWe plant would demonstrate reliable operation of a large salt-in-tube receiver and over 1000 stretched-membrane heliostats. Table 3 presents base case as well as accelerated case central receiver cost performance projections on component and subsystem basis.

3.2.1 Base Case Scenario

In the base case R&D scenario for central receiver, federal funding is assumed to be available to complete the proof of concept step. In this scenario, research will end when testing of the DAR is finished in 1993 and federal money will not be used to support a test at Solar One. If this occurs, commercial-scale central receivers will not be built until at least 2005 (when the technology is close to competitive), and the 5th plant will be delayed until at least 2015. It should be noted that this is an optimistic outlook; the first plant will be only marginally competitive. The first plant must be built, however, in order to provide the basis (in manufacturing and operating experience) for later, more cost-effective plants. Should other factors (such as environmental regulations or fossil fuel prices) change for the benefit of solar thermal technology, this first plant could become far more competitive. In addition, providing the basis for more competitive future central receiver plants will be a key factor in the decision to build the early, marginally-competitive plant. Later plants should benefit from greater production levels and economics of scale. Thus, penetration of the market could actually come much later. It can be seen from Figure 15 that in 2015 the COE for natural gas is expected to be approximately 5 cents greater than the COE from central receivers.

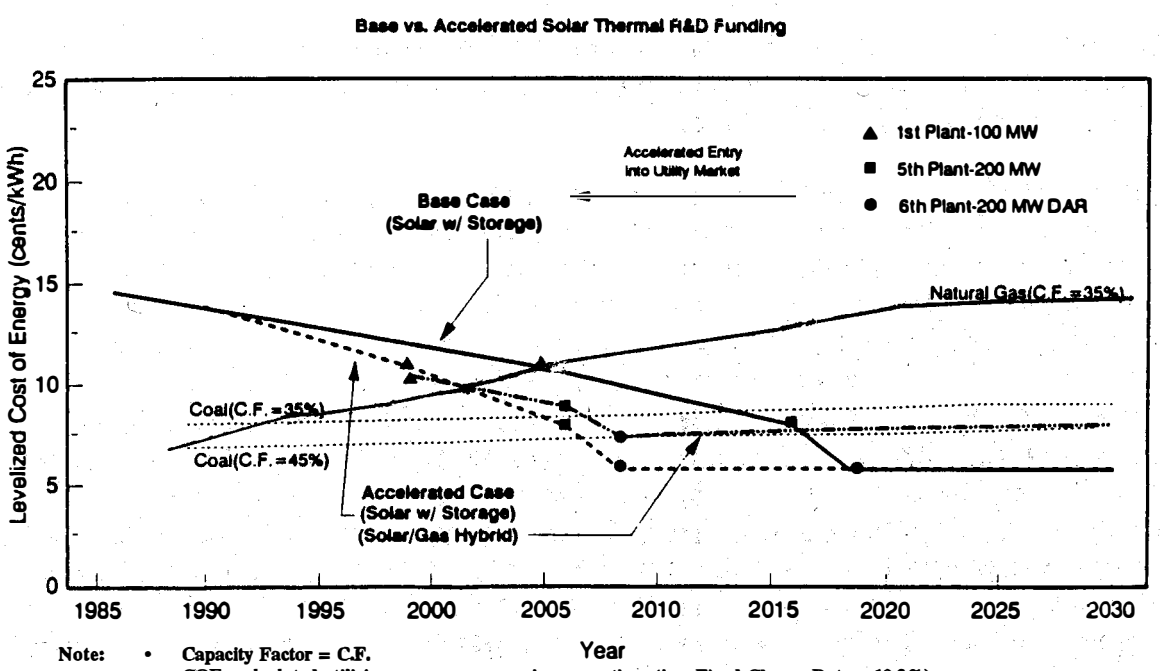
3.2.2 Accelerated R&D Scenario

In the accelerated R&D scenario for central receiver, federal funding is assumed to be available to support a 10 MWe test at Solar One in the early 1990s. Industry is seeking a majority (70%) cost share from DOE on such an endeavor. If the Solar One test is successful, it is believed the industry could begin building a 30-100 MWe plant to operate as early as 1999 (with a minority DOE cost share of approximately 20%). This postulate is supported by information presented in the COE curve. That figure shows that for subsequent plants in the early 2000s, the COE from central receivers is expected to be similar to natural gas plants. With a successful test at Solar One and operation of the first 30 - 100 MWe plant, perceived risk would be low and industry would be willing to build a central receiver which has the same COE as conventional plants, and thus support a faster introduction of subsequent plants. The accelerated funding scenario potentially speeds up the commercial development of central receiver power plants by nearly 10 years for the 5th and 6th plants (see Figure 15).

Table 3. Central Receiver Cost and Performance Projections Base and Accelerated Cases

Technology	ATS/SIT Prototype	First SIT Plant	Fifth SIT Plant	First DAR Plant
Base Case (year)	1986	2005	2016	2018
Accelerated Case (year)	1986	1999	2006	2008
Plant Capacity (MW)	100	100	200	200
Capital Cost ($/kW)				
Heliostats	$1576	962	743	659
Receiver	547	353	273	176
BOS +	1060	1060	840	741
Indirect	716	534	278	236
TOTAL	3900	2910	2135	1813
O&M (mils/kW/yr)	49.0	44.0	33.0	27.0
Capacity Factor	36.8%	36.8%	37.2%	43.1%
Annual Efficiency	14.7%	14.7%	14.4%	17.2%
COE (¢/kWh)	14.2	10.8	7.9	5.7

\+ Includes Thermal Storage, Power Bloc, Field Wiring and Controls



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 15. Central Receiver Technology - Levelized Cost of Energy

3.3 Dish Electric Power Plants

Dish electric concentrators, receivers, and engine/generators have all progressed to testing of the first generation systems. This effort has achieved solar to electric conversion system efficiency of 29% in 25 kWe full scale tests of the United Stirling Model 4-95 kinematic Stirling engine (KSE) mounted at the focal point of Vanguard and McDonnell Douglas glass metal concentrators. While this test demonstrated the feasibility of high performance for the dish-Stirling power generation concept, the high cost of glass metal concentrators and the use of an automotive-derived Stirling engine were recognized to be only a first step in the development process. Stirling Thermal Motors has built and operated a 25 kWe Stirling engine which replaces a conventional crankshaft drive with a variable swash plate drive linkage that transmits and controls power output to the generator. The simplicity and reliability of this improved control mechanism will be the basis for a second generation KSE. The configuration initially developed by Sunpower and MTI, free-piston engines with linear alternator and sodium heat pipe receiver, is being further developed by Cummins and Sunpower for stand-alone modules in the 5 to 10 kWe power range. In the joint DOE/NASA development program for 25 kWe Advanced Stirling Conversion Systems two concepts for free-piston Stirling engines (FPSE) have progressed through the preliminary design stage and are entering the final design and fabrication stages. Cummins/Sunpower is developing the 25 kWe FPSE with linear alternator and Stirling Technology Company/Westinghouse is developing the 25 kWe FPSE with hydraulic output to an induction generator. The design life for the engines is 60,000 hours with a major overhaul at 30,000 hours. These accomplishments provide a substantial base for next steps in the R&D process. Table 4 presents base case as well as accelerated case parabolic dish cost performance projections on component and subsystem basis.

3.3.1 Base Case Scenario

Base case R&D funding for Dish Electric Power Systems provides sufficient resources to take concepts for stretched membrane dish concentrators coupled with advanced Stirling Engines through to System Validation.

Development of dish concentrators has followed the same path as CR heliostats. Initially, dishes were built from commercially available glass/metal reflector materials. While high optical efficiency was demonstrated in 150 m^2 sizes, the need to drastically reduce dish costs without sacrificing performance has led to the development of dishes fabricated from a new class of materials -lightweight, durable, and highly reflective polymer membrane reflectors. Two approaches for dish development are underway. Multi-facet dish concepts can be easily produced and shipped utilizing smaller circular facets, up to 3.5 m diameter, supported on a lightweight space frame. This approach, which requires the least R&D investment and time, which will make the technology available for the near term off-grid market. While these dishes can be easily manufactured, the axis-symmetric facets at off axis positions can only roughly approach true parabolic optics and optical performance is decreased (collector efficiencies in 70 to 75% range). The second approach is to preform or inelastically stress a single monolithic reflective membrane to a true parabolic curvature and then mount the preformed reflector on a hoop rim. A second back membrane encloses the area behind the reflector and allows the internal pressure to be reduced to maintain the parabolic shape. Methods for manufacturing the reflector assembly will require greater precision and these

Table 4. Parabolic Dish Cost and Performance Projection Base and Accelerated Cases

Technology	MDAC Prototype	Stand-alone 5 - 25 kWe	Early Utility 25 kWe	Mass-produced 25 - 30 kWe
Base Case (year)	1985	1997	2002	2007
Accelerated Case (year)	1985	1995	1997	2000
Capital Cost ($/kW)				
Concentrator	$1098	824	563	370
Rec/Engine/Gen	2139	1070	403	437
BOS	75	75	75	75
Indirect	662	394	208	132
TOTAL	3974	2363	1249	1014
O&M (mils/kWh/yr)	22.2	14.4	8.2	7.9
Capacity Factor +	25.3%	25.6%	25.9%	25.9%
Annual Efficiency	22%	20%	22%	25%
COE (¢/kWh)	20.4	12.1	6.4	5.4

+ Solar only mode

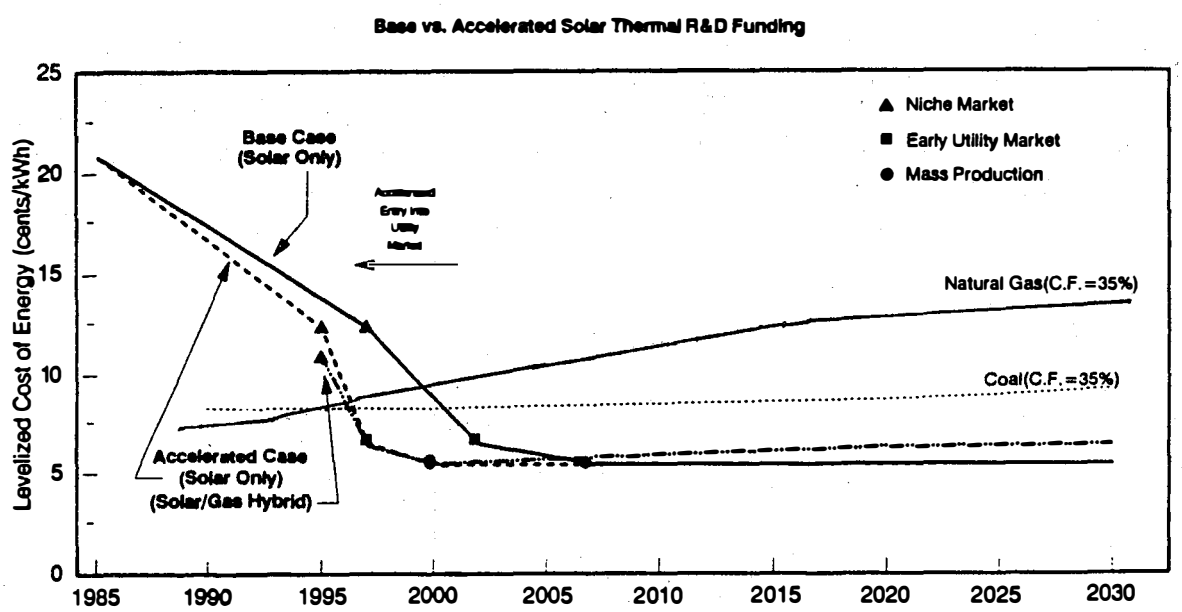
dishes are designed for the utility market where higher efficiencies are justified. The combination of high reflectivity with parabolic optics (efficiency >90%) and light weight construction contributes to a high degree of cost effectiveness ($105-125/m^2). Both multi-facet 3.5 m diameter and preformed single-facet 7 m diameter membrane reflector assemblies are presently being tested and are exhibiting excellent optics.

Heat engine/generator development and testing is furthest along for the 25kWe variable swashplate kinematic Stirling engine and the 5-10 kWe FPSE engines. Prototype FPSE engines with 25 kWe capacity will be tested in 1993. A critical element of the development effort is the substitution of a heat pipe or reflux receiver for a tube heater cavity receiver. The heater head tubes must sustain helium internal pressures of 18 MPa and withstand temperatures up to 800°C with solar flux exceeding 80 kWt. The subatmospheric liquid metal heat transfer process in the heat pipe or reflux receiver eliminates the stresses imposed on the heater head by the temperature variation caused by direct exposure to the solar flux. In tests, prototype receivers have demonstrated 90% efficiency at 800°C.

System validation tests will be designed to assess potential operational problems in the proof of concept phase and confirm the design improvements and evaluate system controls in the system validation phase. The Base Case R&D Scenario will support efforts to field test up to ten of the systems. Even with this level of field testing, the risks of moving toward a limited production capacity will remain high and market acceptance for all but niche markets will be delayed until after 2000 (Figure 16).

3.3.2 Accelerated R&D Scenario

The accelerated R&D scenario for Dish Electric Power Systems will permit a larger number of competing concepts to be brought to the proof of concept stage and will permit the program to carry the most successful prototype systems into the manufacturing validation phase at least two years earlier than the base case. Pioneer, in a study performed for NASA/DOE, estimated that the investment in capital equipment and tooling alone for limited production capabilities would exceed $5.5 million. By sharing the cost of a validation test for cost-effective manufacturing processes for high performance and reliable units for the dish modules, the risk of investing in manufacturing facilities would be reduced. Twenty to fifty dish electric modules built to mass manufacturing specifications would be fielded in off-grid and peaking power applications. The projects would be cofunded by DOE with the majority of project costs met by the private sector or utility sponsors. By demonstrating the capability to build cost competitive generators for the off grid and peak power market, construction contingencies and buyer/investor uncertainty can be significantly reduced. This would allow penetration into niche and domestic utility markets. As shown in Figure 16, this step will be critical to the market acceptance of the technology prior to the year 2000. With initial production facilities in place and the proven capability to generate electricity at nearly half the cost of conventional oil or gas fired plants, a sizeable market would be opened for the technology at a time when need for capacity additions is expected.



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 16. Parabolic Dish Technology - Levelized Cost of Energy

4.0 RATIONALE FOR TECHNOLOGY IMPROVEMENTS

While the previous section postulated two technology development scenarios, this section describes a general set of technical improvements believed possible, without specifying dates by which they will be realized.

Figure 17 portrays the phases of technology development toward commercialization in the context of the STEPS process outlined by the solar thermal industry. Table 5 indicates the implementation steps used to successfully commercialize parabolic troughs and required for central receiver and dish electric technology. This process picks up when the basic research has been completed and testing of individual components at experimental scale has proven the viability of the basic subsystems. The industry has shown that proof of concept has been achieved with the field testing of complete experimental prototypes, including: MISR trough, Solar One, Shenandoah, and Vanguard and McDonnell Douglas dish/Stirling modules. System Validation requires an extended field test of an intermediate scale plant using prototype systems, such as Solarplant 1 and SEGS I. Testing of these units provides verification of design improvements over the initial prototypes and provides longer-term operating data to validate control strategies and hardware. In the Manufacturing Validation stage, the systems must be built from components made to specifications for mass manufacture. These tests confirm that mass-producible components can meet performance, reliability, and O&M expectations. Prior to entering this phase, potential manufacturers must commit to a multimillion dollar investment in limited production facilities. Cofunding, tax incentives, and/or special power purchase offers from utilities (as for the early SEGS 30 MW plants) in this stage substantially reduce the risk of stepping up to a limited production capability. The final step initiates the full commercialization process. The identification of major market areas and placement of orders for multi-MW of capacity per year would allow manufacturers to make the investment in full production capacity. Results of the test market phase provide the experience for reliability verification and fine tuning of system design. The DOE base case R&D scenario provides for Federal Government assistance to industry in developing dish electric systems through the System Validation phase and the Proof of Concept phase for central receivers. An Accelerated R&D Scenario accounts for support to the STEPS Initiative through the Manufacturing Validation phase for dishes and the System Validation phase for central receivers.

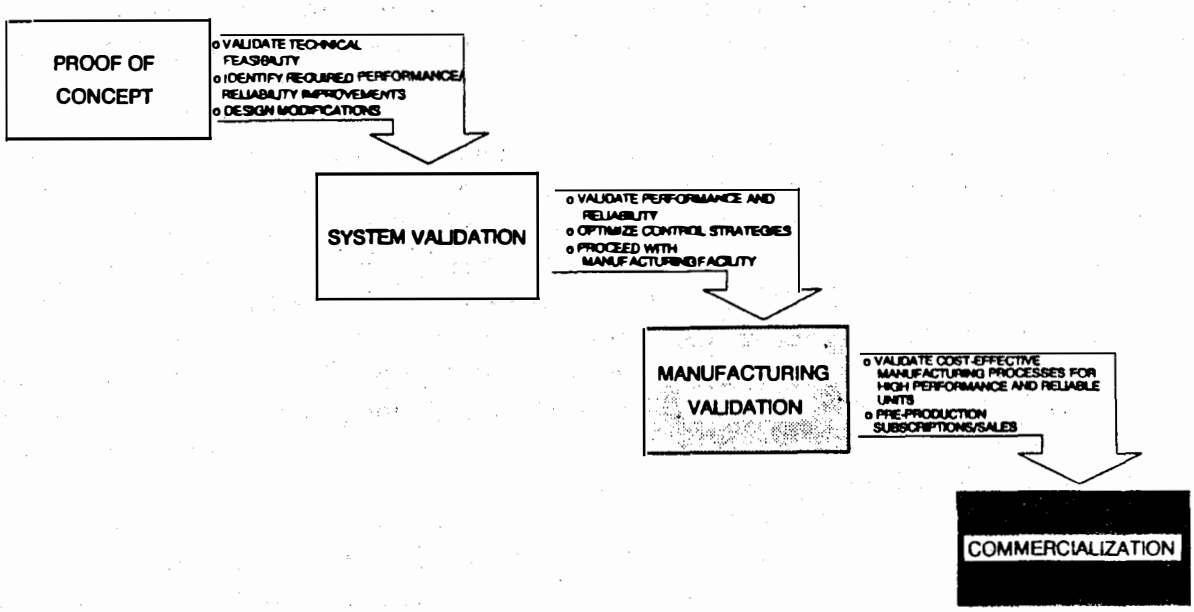


Figure 17. Solar Thermal Electric Technology Development Milestones in Context of Step Process

Table 5. Steps in the Development of Commercial-Scale Solar Thermal Power Plants

PHASE	TROUGHS	CENTRAL RECEIVER	DISH ELECTRIC
Proof of Concept	Component Tests and System Test (MISR)	Component Tests and Solar One (water) System Test	Component Tests and Systems Test (Vanguard, MDAC, Cummins)
System Validation	SEGS I System Test	Solar One (Nitrate Salt) System Test	Utility/User System Test (10 prototype modules)
Manufacturing Validation	SEGS 30 MWe Plants	30-100 MWe Plant	Performance/Reliability System Test (20 to 50 Units)
Commercialization	SEGS 80-200 MWe Plants	100-200 MWe Plant	30-300 MW/year Production

4.1 Parabolic Trough Power Plants

In order to achieve a lower COE, Luz is currently developing a fourth generation collector trough known as the LS-4. Unlike previous trough collector systems which used oil as the heat transfer fluid, the LS-4 will pass water through the collector tubes to create steam. This will permit the removal from the system of an expensive, efficiency-reducing heat exchanger. In addition, flex hoses will be eliminated from the collector design along with other simplifications. The LS-4 is thus expected to have a higher efficiency and lower cost than the LS-3 (Figure 18). The LS-4 will remain a fossil hybrid system since a cost-effective energy storage system does not exist for use with a water/steam system.

Advancements in future years are based on the assumption that larger SEGS plants will be built. Large plants take significant advantages from economies of scale and should be able to achieve a lower COE (Table 6) and be competitive with the COE for natural gas intermediate plants. In order for the Luz trough system to have an even lower COE beyond 1997, a cost-effective thermal storage system will have to be developed to reduce the dependence upon natural gas.

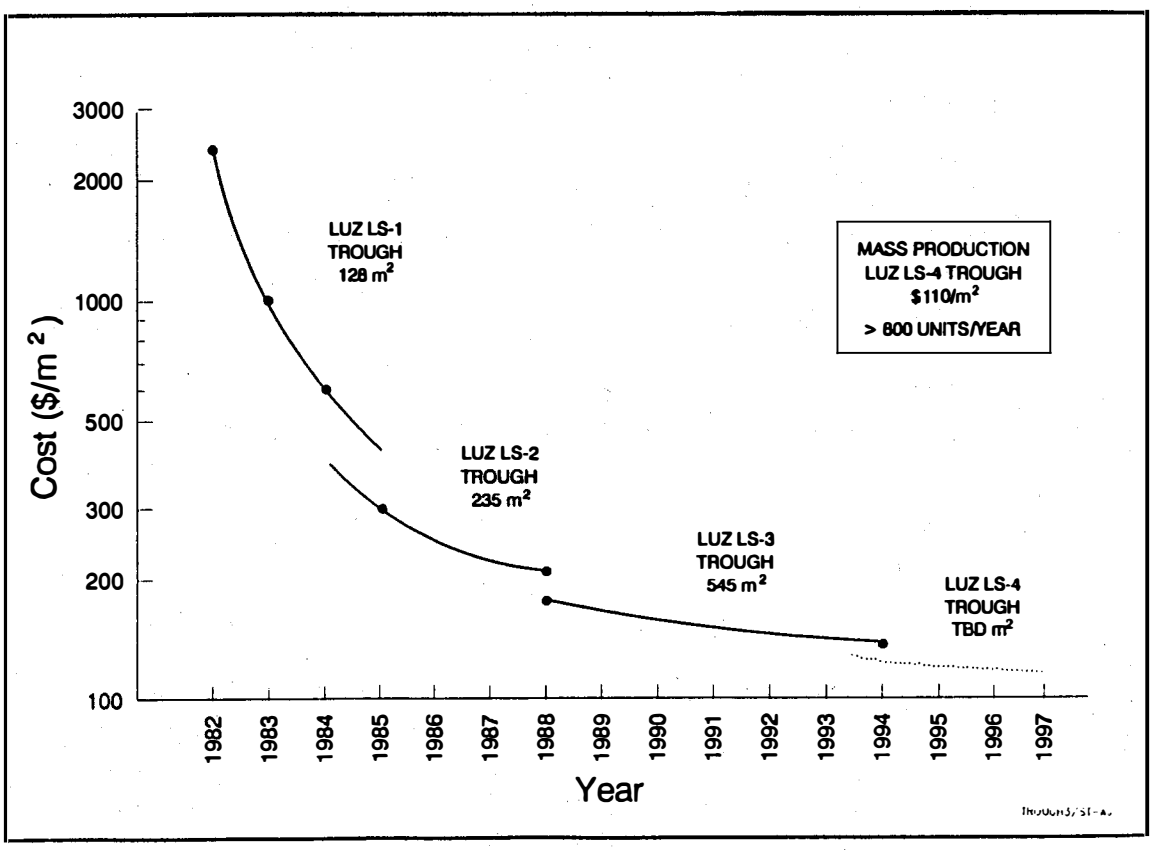


Figure 18. Parabolic Trough

Table 6. Projected Cost of Electricity for Hybrid-Parabolic-Trough Power Plants

TECHNOLOGY DESCRIPTION	PROJECTED COE*	COST REDUCTION COMPONENTS**
1st 80MWe Power Plant (Reference Case) a) 80MWe power plant b) LS-3 Large glass/metal trough c) Oil heat transfer fluid/heat exchangers for indirect steam generation	13.0¢/kWhe	Present system
5th 80MWe Power Plant a) 80 MWe power plant b) LS-3 glass/metal troughs c) Oil heat transfer fluid/ heat exchanger	12.2¢/kWhe	• Concentrator cost reduction due to mass production (1%) • Efficiency improvement from 12 to 14% and reduced BOS costs due to projected learning curve effects (5%) • Overall system cost reduction of 6%
5th 160MWe Direct Steam Power Plant a) 160 MWe power plant b) LS-4 Large glass/metal trough c) Direct steam collector system	9.9¢/kWhe	• Reduction in concentrator cost and increase in efficiency to 15% due to use of LS-4 direct steam trough (5%) • Scale-up and elimination of heat exchanger reduces BOS (19%) • Overall system cost reduction of 24%

* Utilizing common economic assumptions (i.e, Fixed Charge Rate = 10.2%), Value of capacity credits is not included).

** Percentages shown under this column indicate COE cost reduction improvement compared to reference case.

4.2 Central Receiver Power Plants

To produce economical power from a central receiver, plants in the 100 to 200 MWe range should be built. This is because large plants realize significant advantages from economies of scale and reduced operation and maintenance costs. Several U.S. utilities have expressed interest in central receiver technology and recently completed a $4 million cost-shared study of the economics of power plants in this size range (Table 7). It was predicted that the 1st commercial scale plant would be 100 MWe in size and utilize a salt-in-tube receiver and stretched membrane heliostats. It was also predicted that such a plant would produce power for about 11¢/kWh. Since prototypes of all solar components analyzed in the utility study have been built and tested at Sandia Laboratories, it is believed that such a plant could be built today.

If the first 100 MWe plant is successful, the utility study recommends that the next significant advancement would be to build a 200 MWe plant. This plant enjoys a greater economy of scale than the 100 MWe plant. Economies of scale have a significant impact on the COE for large power plants. This is because the cost of power plant components and personnel do not scale linearly with plant size. The utility study also predicted that an advanced salt-in-tube receiver would be used in the 1st 200 MWe plant. This receiver would have a 20% higher flux limit than the receiver in the 100 MWe plant and would be more efficient. As production levels of stretched membrane heliostats increase, their cost is predicted to decrease. Between 3000 and 5000 heliostats per year should be produced by the time 200 MWe power plants are built. At this production level, heliostats costs could drop from $\$105/m^2$ to $\$75/m^2$. This heliostat cost reduction will contribute significantly in achievement of 200 MWe system COE of 7.9¢/kWhe. However, some form of early demonstration and integration of these advanced concentrator and receiver subsystems is critical to achieve COE targets.

Further CR system COE reduction will be achieved by constructing a 200 MWe power plant using the more efficient direct absorption receiver (DAR) over the salt-in-tube receiver. Development of the nitrate salt cooled receiver and storage system was completed in 1988. Use of the heat storage media as the receiver heat transfer fluid improves overall efficiency and operation during solar transients. The receiver is designed to operate at 593°C. The potential to achieve even higher efficiencies and lower costs is being explored through the development of the DAR (Figure 19). In the DAR, a nitrate salt film falling on the surface of a vertical plate directly absorbs the high intensity flux. This receiver is scheduled to be tested in 1992. Since the DAR does not have a flux limit it can be much smaller than a salt-in-tube receiver. Lack of tubes allows the receiver to run at a lower surface temperature, start up faster, and use less pumping power. These factors should improve the annual efficiency of the receiver from 80% to 90% and the plant efficiency from 15% to greater than 17%. Since it is more efficient, the plant will produce more annual energy and will be able to achieve a system COE target of 5.7¢/kWhe. A comparison between central receiver and trough systems is shown in Table 8.

Table 7. Projected Cost of Electricity for Central Receiver (CR) Power Plants

TECHNOLOGY DESCRIPTION	PROJECTED COE*	COST REDUCTION COMPONENTS**
100MWe Power Plant Study (Reference Case) a) 100 MWe power plant b) Large area salt-in-tube receiver c) Large area glass/metal heliostats	14.2¢/kWhe	• 1986 Technology
1st 100MWe CR Power Plant a) 100 MWe power plant b) Large area salt-in-tube receiver c) Large area stretched-membrane heliostats	10.8¢/kWhe Solar Mode 10.3¢/kWhe Hybrid Mode (23% gas input)	• Low-cost membrane heliostats (18%) • Reduced receiver cost for advanced nitrate salt receiver (6%) • Overall cost reduction of 24%
5th CR Plant - 1st 200MWe Power Plant a) 200 MWe power plant b) Advanced salt-in-tube receiver c) Large area stretched-membrane hellostats	7.9¢/kWhe	• Reduced concentrator cost (25%) • Reduced receiver cost with higher flux limit (11%) • Balance of system cost reduction due to scale effects and reduction of indirect costs due to plant maturity (9%) • Overall 45% reduction
6th CR Plant - 1st 200MWe DAR Plant a) 200 MWe power plant b) Direct absorption receiver c) Large area stretched-membrane heliostats	5.7¢/kWhe	• Mass-produced stretched membrane hellostat concentrator (27%) • DAR results in reduced receiver costs and increased plant efficiency (24%). • Balance of system cost reduction due to scale effects and reduction of indirect costs due to plant maturity (9%) • Overall 60% reduction

* Utilizing common economic assumptions (I.e., Fixed Charge Rate = 10.2%), Value of capacity credits is not included.

** Percentages shown under this column indicate COE cost reduction improvement compared to reference case.

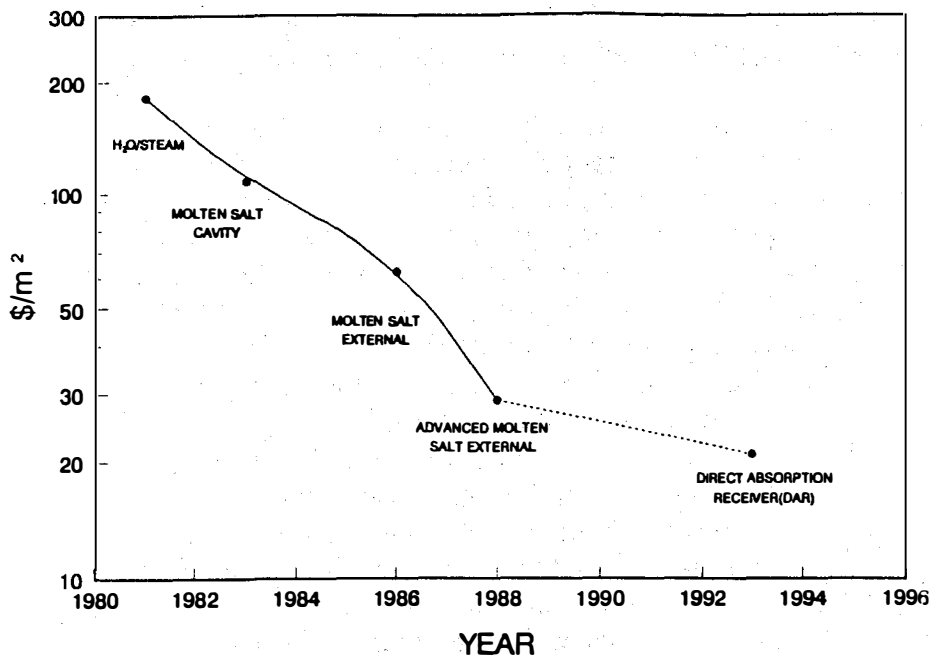


Figure 19. Central Receiver

Table 8. Projected Levelized Energy Costs (Trough/Central Receiver Comparisons)

	LUZ TROUGH		CENTRAL RECEIVER			
	80MWe/Year PRESENT	160MWe/Year GOAL	1st Plant 100MWe	1st Plant 100 MWe HYBRID	5th Plant 200 MWe	1st DAR Plant 200 MWe
INSTALLED CAPITAL COST ($/kWe)	2887	1850	2910	2007	2135	1813
ANNUAL ENERGY EFFICIENCY - SOLAR MODE	12%	15%	14.7%	14.7%	14.4%	17.2%
METHOD FOR ENHANCED LOAD MATCHING	25% Natural Gas	25% Natural Gas	Thermal Storage	23% Natural Gas	Thermal Storage	Thermal Storage
CAPACITY FACTOR	35.0%	35.0%	36.8%	35.0%	37.2%	43.1%
LEVELIZED ENERGY COSTS* (¢/kWh)	13.0	9.9	10.8	10.3	7.9	5.7

* Utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
Value of capacity credits is not included.

The major projected gains in concentrator system cost reductions are attributable to the substitution of stretched membrane optical elements for currently used glass/metal reflectors. This extremely lightweight system (75% weight reduction) system with fewer parts and large area design reduces costs for both structural support and optical surfaces and is a major contributor in achieving high overall system efficiency at lower cost (Figure 20).

Central receiver plants employ a low-cost and highly efficient (99%) molten salt storage system which allows operation during solar transients and low insolation and improves the economics of central receiver power plants for two major reasons. First, capacity factor is increased by adding a large energy storage system to the solar power plant and COE is reduced. Second, storage allows the plant to produce power during periods of peak demand when electricity production has its highest value. The capacity factor selected in the U.S. utility study was 37% and required 6 hours of thermal storage. This capacity factor was selected to optimize the benefit/cost ratio based on PG&E's electric grid. In the DAR plant, the capacity factor is increased to 43%. Without storage or hybrid capabilities, solar technologies typically attain a capacity factor near 25%. This capacity factor is typically the optimum value for photovoltaics and non-hybrid trough and dish technologies because large battery storage is deemed not to be economic. This is <u>not</u> the case for central receiver technology. Use of thermal storage affords greater utilization of the turbine generator system. A 200 MWe turbine generator system costs approximately $84 million. The cost per kilowatt-hour, associated with this part of the plant, is reduced if this item is allowed to produce more annual electricity, i.e. allowed to achieve a higher capacity factor. It is possible that, in the near-term, solar/natural gas hybrid central receiver plants using approximately 23% natural gas will be used to achieve capacity factors equal to similar solar-only systems employing thermal storage. While natural gas is relatively cheap, the hybrid plant will have a COE of approximately 10¢/kWh. As natural gas prices increase, however, solar operation with thermal storage becomes the lower-cost option, leveling off at below 6¢/kWh.

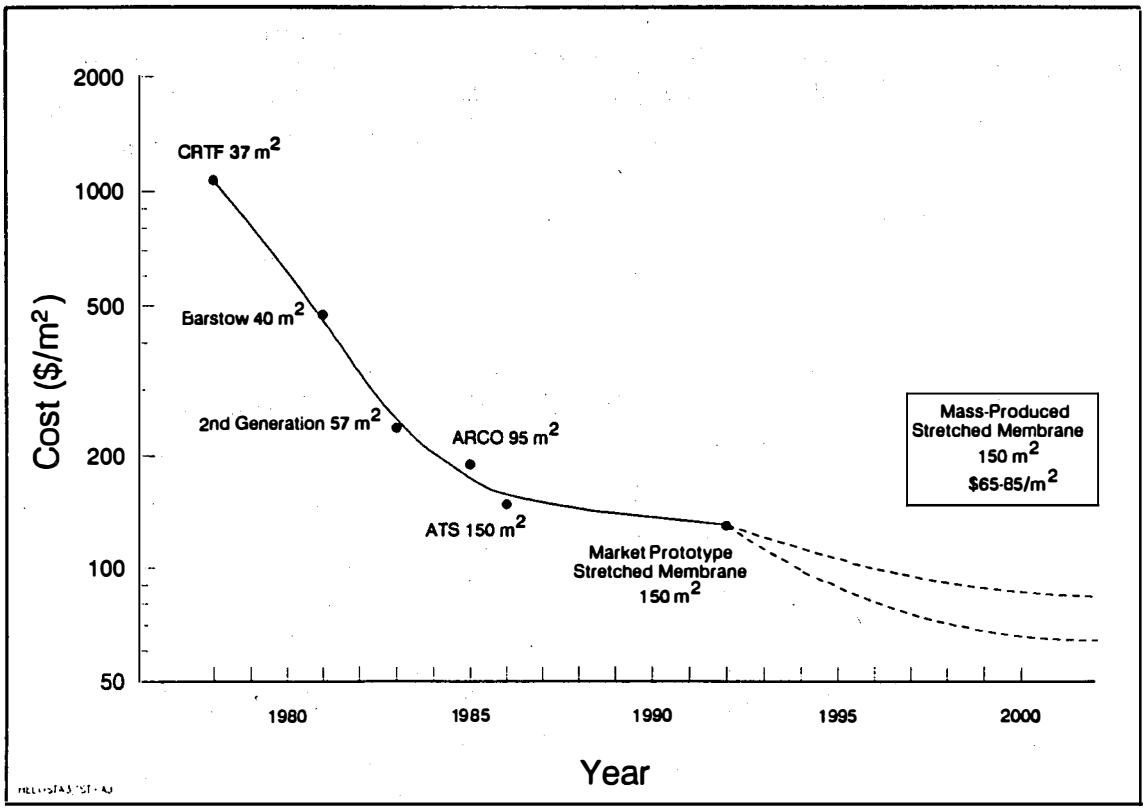


Figure 20. Heliostat

In coming decades, several central receiver plants will be built and a significant solar industry will be established with multiple companies competing for the same work. The costs of components in the Utility Study were, in general, based on quotes from single vendors. It is anticipated that competition will reduce the costs of plant components further.

4.3 Dish Electric Power Plants

Future improvements under development in engine and concentrator technology will drive the cost of electricity down into the competitive ranges with most conventional utility peaking and intermediate power generation units. These improvements are discussed below.

As in the case of central receivers, major gains in system cost reductions are expected from the substitution of stretched membrane optical elements for currently used glass metal reflectors. Both multiple facet and single facet dish reflector configurations are being developed. This lightweight design reduces costs for both structural support and optical surfaces and contributes significantly in achieving higher overall dish module system efficiency at lower cost (Figure 21).

Two alternative receiver concepts to improve both efficiency and rates of heat transfer to the engine heater head are in development, they are heat-pipe and pool-boiling liquid metal receivers. The liquid metal reflux boiler directly boils off the liquid metal pooled behind the absorber while the heat pipe configuration wicks the liquid metal over the inner surface of the absorber/evaporator. The metal vapor then condenses on the engine heater tubes effectively providing a small temperature drop and a one-way mechanism for heat transfer with uniform heater tube temperatures, resulting in higher receiver efficiency.

A high performance (45% efficiency at 800°C), low maintenance heat engine/generator coupled with the high efficiency dish concentrator offers the potential of very high solar-to-electric conversion efficiency (near 33% solar input to electric conversion efficiency at peak power conditions) in relatively small modular units of 5-25 kWe. Kinematic Stirling engines with either a swashplate or conventional crankshaft drive linkage are in the final stages of development. The free-piston Stirling engine (FPSE), currently in development, can deliver performance comparable to the kinematic and also can potentially have engine life of 50-60,000 hours and minimize engine maintenance significantly (Figure 22).

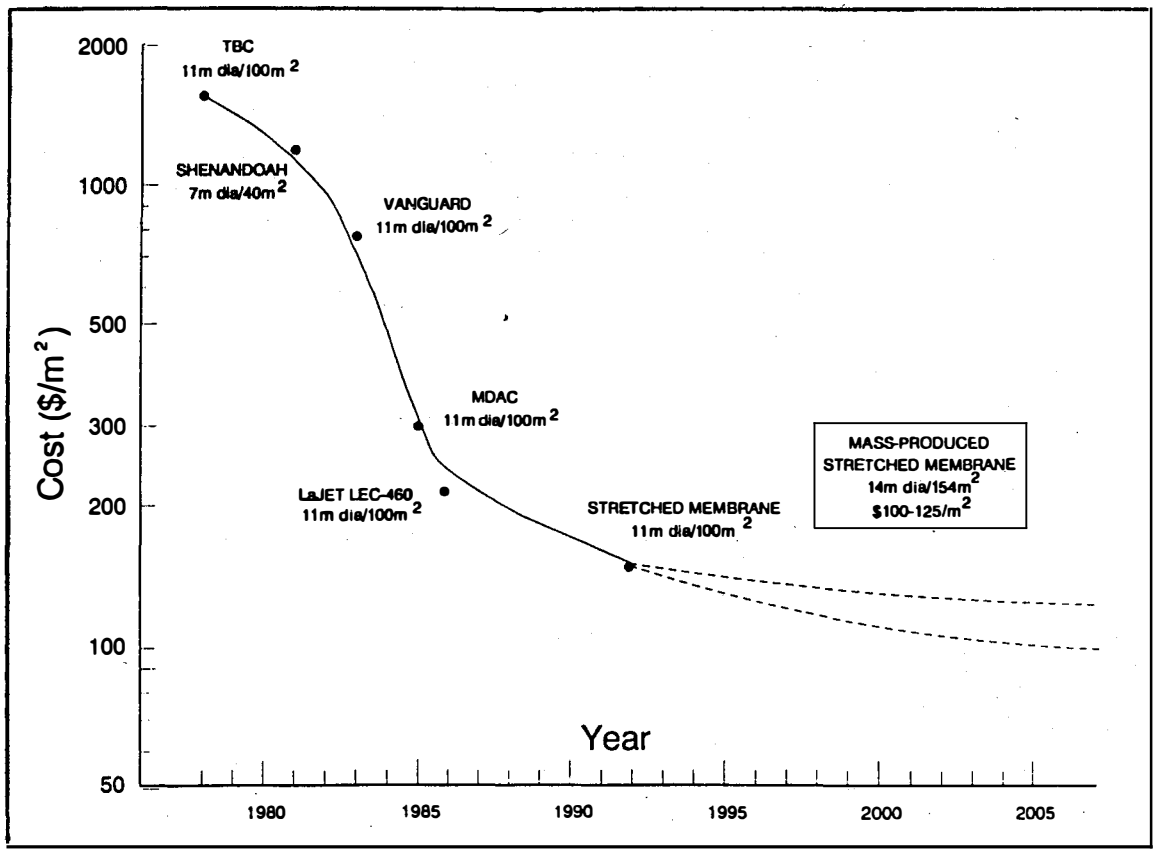


Figure 21. Parabolic Dish

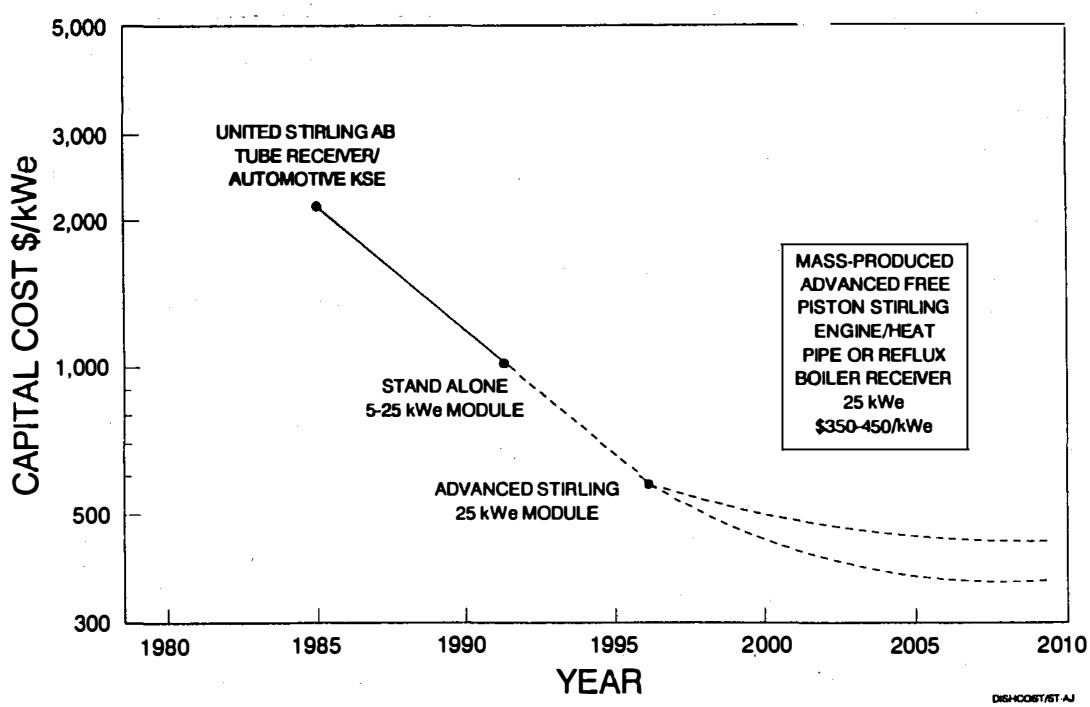


Figure 22. Solar Thermal Dish Electric Technology Receiver-Engine-Generator Subsystem Cost

Table 9 lists the underlying technology improvements which are the basis for cost and performance projections for Dish Electric Technology. The COE estimate for available technology is based on the test experience for the 25 kWe United Stirling Kinematic Engine (automotive design derivative) operated in both the Advanco Vanguard and McDonnell Douglas/glass/metal parabolic dishes. The cost projections for this technology were made by McDonnell Douglas in 1985 for a production level of 200 units per year. The hydrogen piston seals for these automotive design derivative engines would require annual replacement as would the directly-heated heater tubes, resulting in high O&M costs.

Table 9. Projected Cost of Electricity for Parabolic-Dish Power Plants

TECHNOLOGY DESCRIPTION	PROJECTED COE*	COST REDUCTION COMPONENTS**
1st 25kWe MDAC Dish Module (Reference Case)		
a) MDAC glass/metal concentrator b) USAB 4-95 kinematic Stirling engine and tube-type receiver	20.4¢/kWhe solar mode	1985 Technology
5-25kWe Stand-alone Dish Modules -Near-term Niche Markets		
a) Multi-facet stretched membrane concentrator - spherical optics b) 5-25 kW Stirling engine c) Reflux boiler or heat pipe receiver d) 3 MWe/year	12.1¢/kWhe solar mode 10.5¢/kWhe hybrid mode (20% gas input)	• Low cost membrane multi-facet concentrator (9%) • Reduced engine cost and improved engine life and reliability with advanced receiver (31%) • Overall 41% improvement in COE • Hybrid operation improves capacity factor and efficiency for additional 10% COE reduction
25 kWe Modules Mass-produced for Utility Scale Plant		
a) Large area, single facet, stretched membrane dish b) 25-30 kWe advanced Stirling engine c) Reflux boiler or heat pipe receiver d) 300 MWe/year	5.4¢/kWhe solar mode 5.5¢/kWhe hybrid mode (20% gas input)	• Low cost/high optical efficiency single-facet membrane dish (20%) • Scaled up engine designed to high production tolerances (54%) • Overall 74% improvement in COE • Hybrid operation improves capacity factor and efficiency but increased costs of natural gas result in higher COE

* Utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%), Value of capacity credits is not included.

** Percentage shown under this column indicate COE cost reduction improvement compared to reference case.

In the near term, a free-piston Stirling (linear alternator) or advanced kinematic Stirling (potentially the swashplate design) will be available in the 5 to 25 kWe range. With helium replacing hydrogen in the engines, the relative simplicity and potentially high reliability of either the kinematic Stirling with swashplate control and drive linkage in a helium pressurized crankcase or the free-piston Stirling engine (FPSE) with linear alternator, coupled with multifaceted stretched membrane dishes is expected to reduce concentrator, engine, and receiver costs by a factor of 2 and O&M costs by 40%. Although the multi-faceted dish represents a relatively low cost, lightweight design, the spherical optics of the facets limit the optical efficiency of the concentrator. A design life of 50,000 hours appears achievable for either the swashplate or advanced Stirling engine. Hybrid operation reduces COE to 10.5¢/kWh by increasing plant capacity factor and efficiency.

A single-facet stretched membrane concentrator and advanced Stirling engines with 25 to 30 kWe peak output are under development for utility and industrial power markets. A single facet reflector shaped to parabolic optics can be installed at low cost (105-125 $/m^2). The lightweight design permits additional cost reductions in structural supports and tracker drives. The cost of the concentrator in limited production is based on a manufacturing cost estimate for a petal faceted lightweight reflective film dish with true parabolic optics. Although the optics of the two dishes are comparable, the cost estimate is conservative since a single-facet stretched membrane could further reduce production costs. The advanced Stirling engine with a projected life of 60,000 hours and minimal maintenance will provide a further improvement in the Dish Electric System COE. Based on the estimated manufactured cost of $8030 (FOB Factory) for the 26 kWe (peak) engine/generator and cost reductions in the stretched membrane concentrator a total installed cost of $1250/kWe is projected.[2] Pioneer Engineering and Manufacturing company prepared manufacturing cost estimates for the conceptual design of the STC FPSE based on production levels of 10,000 units/yr (250 MWe/yr). General Engineering, Inc. recently updated the Pioneer cost estimates for the NASA/DOE preliminary design report for the STC engine. The COE for this configuration is projected to be 6.4 ¢/kWh. Cofiring the engine with natural gas in a hybrid configuration provides the same advantages which accrue to the Luz parabolic trough plants. Hybrid operation increases plant capacity factor and allows the plant to reliably provide full capacity output during peak demand periods. While this effect does not reduce the COE as computed for this report due to escalating gas prices, relative plant economics will improve when utility capacity credits for peak generation are factored into the analysis. Table 10 summarizes Dish Electric cost and performance improvements in perspective with the trough electric technology.

Increased production will further reduce concentrator costs. The cost of the complete system is expected to be near $1000/kWe (installed) in mass production. This is based on a similar manufacturers cost estimate for the Cummins FPSE with linear alternator initially developed by MTI under the joint DOE/NASA Stirling R&D program. Early results from the preliminary design for this engine configuration by Cummins indicates peak power output of 30 kWe and efficiency of 34% for the receiver-engine-generator subsystem.

[2] Costs in 1990 dollars

Improved power output and efficiency coupled with higher production levels for membrane dishes yield a COE of 5.4 ¢/kWh for solar only operation and 5.5 ¢/kWh for hybrid operation. Additional cost reductions will occur over the next decade due to learning curve and competition effects as the technology makes inroads into the utility power market for modular 30 to 50 MWe plant capacities.

Table 10. Projected Levelized Energy Costs (Trough/Dish Stirling Comparisons)

	LUZ TROUGH		DISH/STIRLING					
	80 MWe/YEAR PRESENT	160MWe/YEAR GOAL	3 MWe/YEAR EARLY NICHE MARKET		30 MWe/YEAR EARLY UTILITY MARKET		300 MWe/YEAR UTILITY MARKET	
CAPITAL COST 3($kWe)	2887	1850	2360		1250		1000	
ANNUAL ENERGY EFFICIENCY	12%	15%	20%		22%		25%	
METHOD FOR ENHANCED LOAD MATCHING	25% Natural Gas	25% Natural Gas	Solar only	<20% Natural Gas	Solar only	<20% Natural Gas	Solar only	<20% Natural Gas
CAPACITY FACTOR	35.0%	35.0%	25.6%	35%	25.9%	35%	25.9%	35%
LEVELIZED ENERGY COSTS* (¢/kWh)	13.0	9.9	12.1	10.5	6.4	6.3	5.4	5.5

* Utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
Value of capacity credits is not included.

4.4 Rationale Summary

To arrive at a justifiable rationale for the Solar Thermal Electric Technology and to establish credible scenarios for the solar thermal technology implementation for the National Energy Strategy (NES), a three step process was used to establish a schedule combined with cost and performance projections for the introduction of Solar Thermal Electric power systems in the utility markets.

Efforts to bring solar thermal systems to the marketplace are already showing measurable results. Building on the wealth of system experience developed in the DOE program, several companies have made commercial sales of parabolic trough industrial process heat systems. Luz International, for example, projects installation of approximately 700 MWe of power generating stations in the United States by 1994. Today, these parabolic trough systems generate electricity below 10¢/kWh (according to Luz's economic assumptions)[3], with the potential for even lower cost.

In 5 to 7 years, solar thermal systems based on advanced components should find substantially expanded domestic and export market opportunities. These systems will perform better and be available at lower cost than systems at present. One example is central receiver electric power plants that use stretched membrane heliostats and an advanced nitrate-salt receiver. Another is 5 to 25 kWe dish-electric systems, which use low-cost membrane concentrators and advanced focal-mounted engines. Such dish-electric systems can run with solar or fossil fuel for remote and grid-connected markets.

According to the National Energy Strategy Study, the potential market for electric power generation in the southwestern United States alone could be 35,000 MWe in the next decade. Developing export markets for solar thermal systems can further expand this market base. The DOE strategy for moving solar thermal research to the marketplace involves improving cost effectiveness and reliability of solar thermal components and establishing additional early markets with high strategic or economic value to U.S. industry. The strategy also includes establishing cost-shared industrial partnerships that will improve the competitiveness of existing solar thermal electric systems.

In order to provide a rationale for technology improvements and a uniform basis for comparing various technologies, a standardized model including consistent economic assumptions was utilized to calculate cost of electricity (COE) values. Due to the variability of capacity credit payments from utility to utility, these payments are not included in the model. The use of storage or hybrid operation (using fossil fuels) allows Solar Thermal plants to increase these payments, thus significantly improving the overall plant economics. The ability to serve peak demand is valuable because it replaces typically high-cost energy. Other factors including various ownership scenarios and increasingly stringent environmental regulations will also improve economics for solar thermal plants relative to conventional options. Figures 23, 24, and 25 display the projected technology improvements, timing and COE for the introduction of Parabolic Trough/Hybrid power plants, Central Receiver power plants and Dish Electric power plants, respectively. The following paragraphs highlight the

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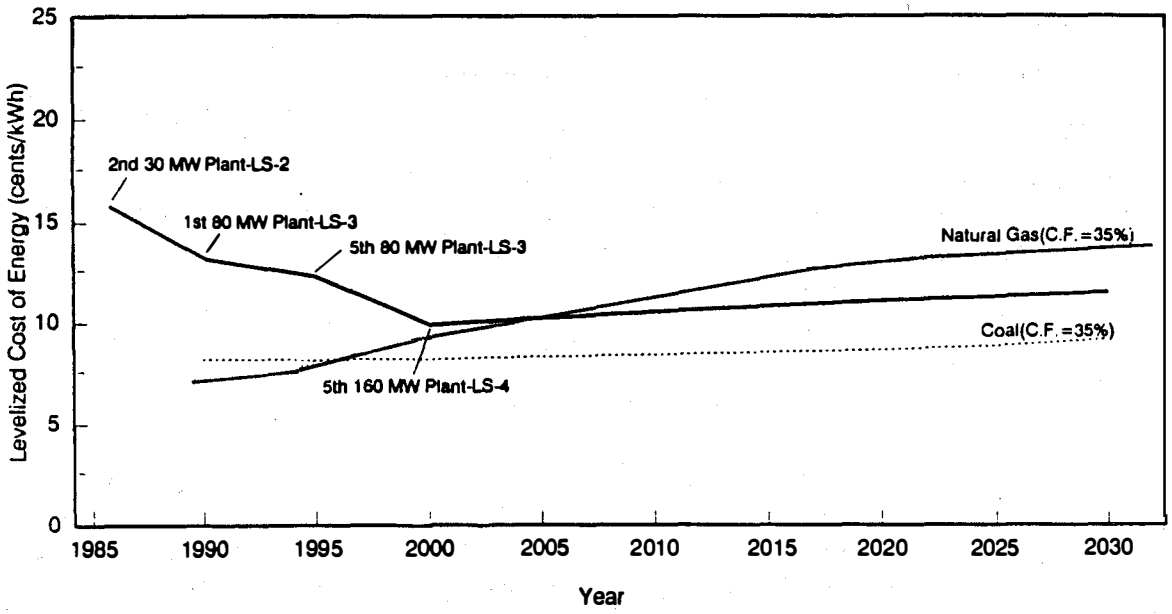
[3] Luz's economic assumptions include capacity credits and also differ from those utilized for the analysis in this document. Therefore, the values are not directly comparable.

results of the analysis and the R&D programs (base and accelerated) that are required to achieve the performance, reliability and cost improvement necessary for commercial success.

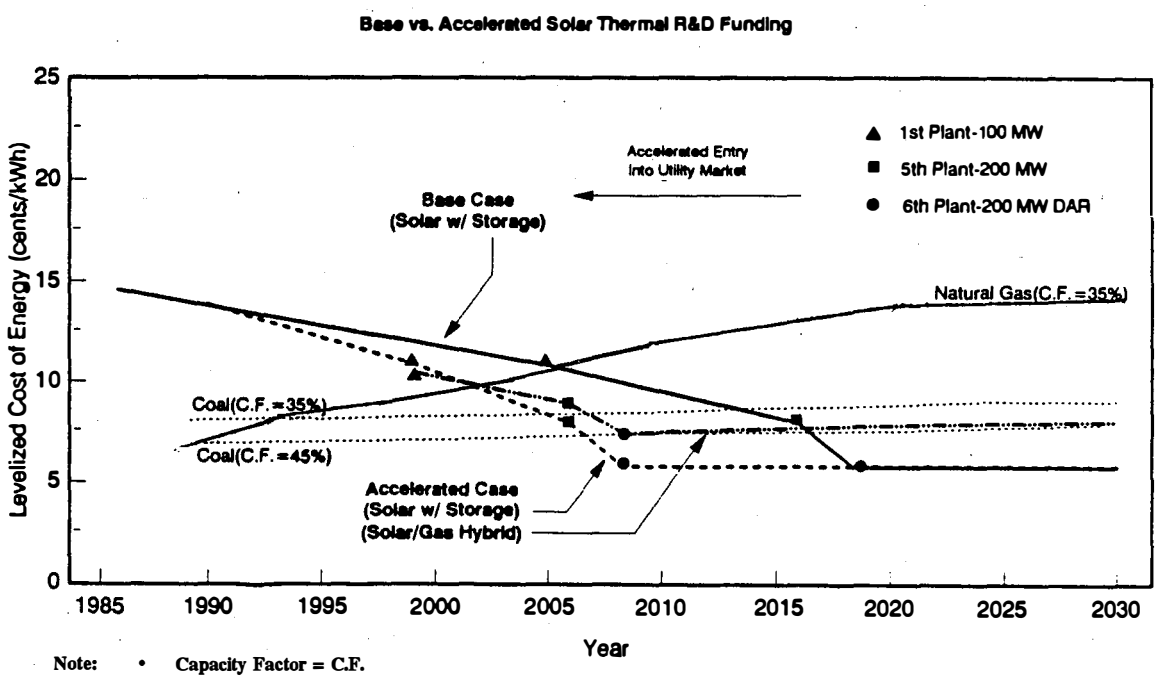
Parabolic trough systems are currently being commercialized in the U.S., primarily by Luz under signed contracts through 1994. It is anticipated that sales of these systems will continue with Luz's development of the LS-4 trough systems by 1995. Therefore, base and accelerated case scenarios for troughs are the same. As can be seen in Figure 23, the COE for troughs operating in a hybrid mode will be comparable to the COE for natural gas intermediate plants after the introduction of several 160MWe, direct-steam generation plants. This plant will attain performance improvements due to economies of scale, the lower cost, fourth-generation concentrator and learning curve effects. At this point, the COE for the fifth plant is projected to be 9.9¢/kWh. The COE after this point will increase due to escalating natural gas price projections of EIA. Development of low-cost thermal storage could lead to reduced dependence upon natural gas, resulting in lower overall COEs. In a more accelerated case, there could be meaningful activities with thermal storage and operations issues to lower COE.



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 23. Parabolic Trough/Hybrid Technology - Levelized Cost of Energy

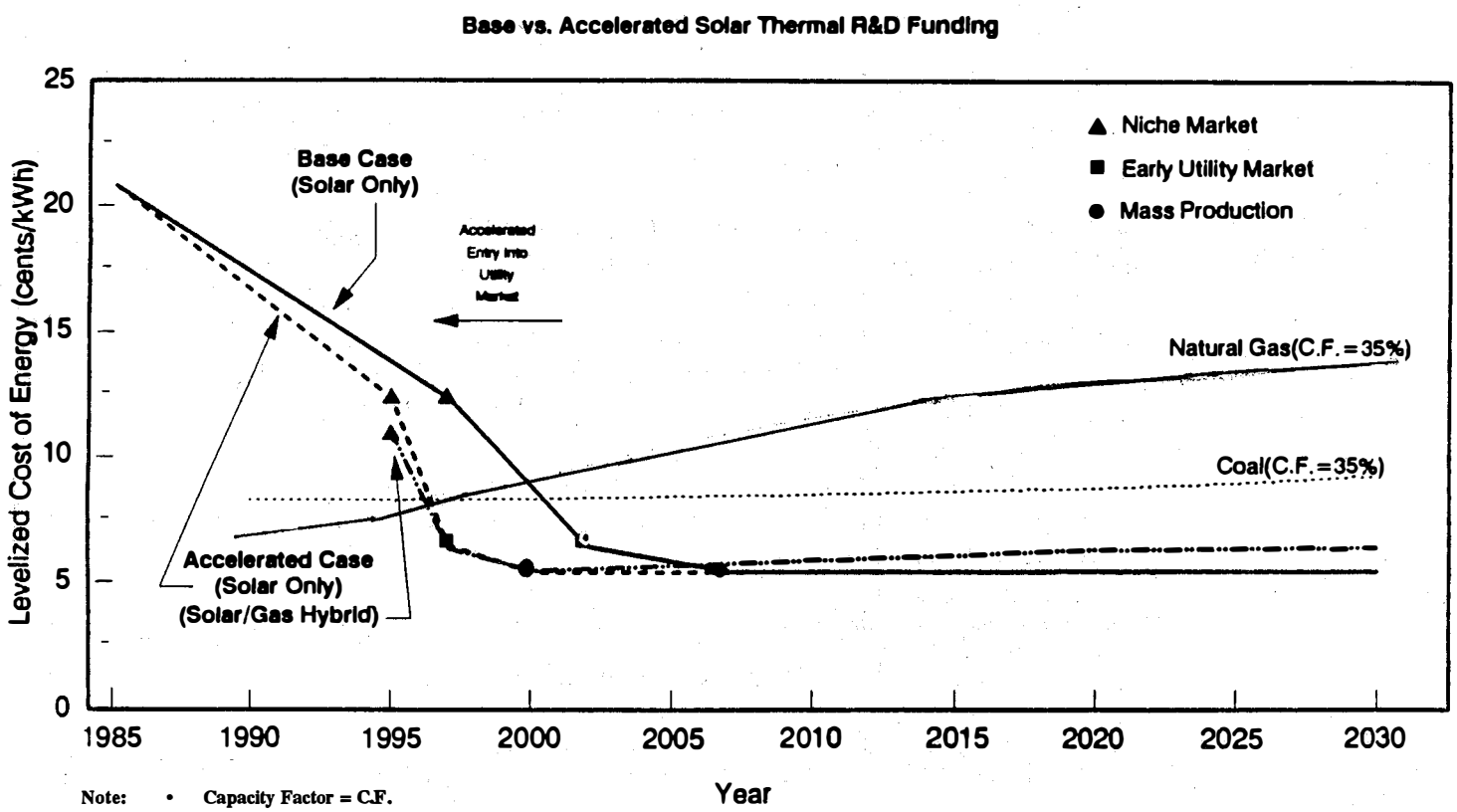
In the accelerated case, Central Receivers (CR) would become competitive with natural gas turbine plants by the year 2002 with the introduction of the salt-in-tube system configuration in year 1999. By the fifth CR plant (the first 200 MW plant), learning curve effects and risk reduction in addition to design improvements will result in a COE that is 3/4 that projected for natural gas intermediate plants. The introduction of the highly efficient and cost effective Direct Absorption Receiver (DAR) subsystem by the 6th CR plant will bring electricity generating costs within the range of competition with baseload power generation from coal. Efficient and very cost effective nitrate salt storage allows the central receiver plant to achieve capacity factors exceeding 40%. The technical and economic risk of fielding CR technology in the 100 to 200 MWe range would be reduced with DOE cost sharing in the construction of a 10-30 MWe plant and potentially accelerate the CR entry into the domestic utility market by almost ten years based on current EIA projections of coal, natural gas, and oil fuel prices. (See Figure 24)



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 24. Central Receiver Technology - Levelized Cost of Energy

In the accelerated case for Dish Electric systems, niche market applications in the remote/off-grid power and international power markets would be accessible to the industry by 1995. At a projected COE of under 13¢/kWh, parabolic dish generators would compete favorably with diesels, photovoltaics, and other systems designed for remote power generation. The combination of a multi-faceted, stretched membrane dish, combined with a 5 to 25 kWe free-piston or kinematic Stirling engine with high solar to electric conversion rates and limited production economics are the primary contenders for this market. As early as year 1997 continued DOE support for the development and testing of the 25 kWe Dish Stirling system would lead to early introduction of the technology in the domestic utility markets particularly in the southwest. DOE support for a field test at a utility of a 30 MWe peaking power plant based on the low cost, high optical efficiency of stretched membrane dish modules coupled with the long life, high conversion efficiency 25 kWe Advanced Stirling engine/generator, will provide the basis for the utility industry to evaluate the commercial potential of the technology in operation. With a COE projected near 5.4¢/kWh in mass production, the Dish Stirling system will compete very favorably with gas turbines in peaking and intermediate load applications. Minimal use of natural gas co-firing (less than 20%) will enhance plant capacity factors and allow the plants increased reliability in meeting peak demand requirements. The COE for hybrid operation (at a capacity factor of 35%) is projected to be slightly higher than solar only operation. Due to the higher capacity factor of the hybrid dish plant, however, the overall economic picture will be better than that of the solar-only plant, due to greater capacity credit payments. With the follow through to the utility field test, it is projected that entry into the utility market could be accelerated by potentially five years as shown in the dish R&D scenario. (See Figure 25)



Note:
- Capacity Factor = C.F.
- COEs calculated utilizing common economic assumptions (i.e., Fixed Charge Rate = 10.2%)
- Value of capacity credits is not included.

Figure 25. Parabolic Dish Technology - Levelized Cost of Energy

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Section 7

TECHNOLOGY EVOLUTION RATIONALE FOR WIND TECHNOLOGY

October 5, 1990

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Technology Evolution Rationale for Wind Energy Technology

Preface

This paper is intended to provide detailed justification for the base and accelerated case wind energy cost and performance projections for the National Energy Strategy. It is a supplement to the document Renewable Energy Technology Characterizations, March 20, 1990. As such, it reviews the basic principles of wind energy conversion, the previous contributions to technical progress of the Federal Wind Energy Program, discusses the market status of wind energy, and identifies user requirements that dictate the form that the technology must take and the historical role of the wind industry in meeting these needs. It projects likely trends in the performance and cost of the technology based on the expert judgment of laboratory and industry experts. Two scenarios are assumed for projections: a base case in which the current trends in industry and technology development continue in a business-as-usual sense, and an accelerated wind R&D case in which the pace and scope of the Federal program is modestly increased. Of course, since projections are never perfect, there is some uncertainty associated with each scenario. However, based on what the entrepreneurial wind industry has achieved in the 1980s and the major milestones contributed by the Federal Wind Energy Program in that same period, it is believed that the scenarios are reasonable.

1.0 INTRODUCTION

1.1 Technology Description

Wind is a nondepletable resource that can provide significant quantities of energy to support the nation's energy needs. Wind is created primarily by the sun's uneven heating of the earth's surface and by the rotation of the planet. Wind energy conversion systems (WECS) are a means of converting the wind resource to a useful form of energy, such as electricity or mechanical power. Wind turbines have been deployed in sizes ranging from below 1 Kw to 4 MW. For the last decade, electricity applications have predominated, but in earlier years, wind turbines had been used for small stand-alone applications such as water pumping and farm power needs.

Although the details of wind turbine aerodynamics and structural dynamics are quite complex, the basic working principle of the wind turbine is relatively simple. (see figure 1) Turbine blades interact with the air in much the same way as do aircraft wings. When wind moves across the airfoil-shaped blades, lower pressures are created on the more rounded surface. The net pressure differential between the sides of the blades creates aerodynamic lift, the primary force acting on the rotor, causing it to turn. The rotating blades drive the gear box and electrical generator.

A wind turbine system, as shown in figure 1, contains five basic subsystems: (1) a rotor, usually consisting of two or three blades; (2) a drive train, generally including a gearbox and generator; (3) a tower and foundation that supports the rotor and drive train; (4) various turbine supporting systems including controls and electrical cables; and (5) "balance-of-station" subsystems which, depending on the application, might include roads, ground support equipment

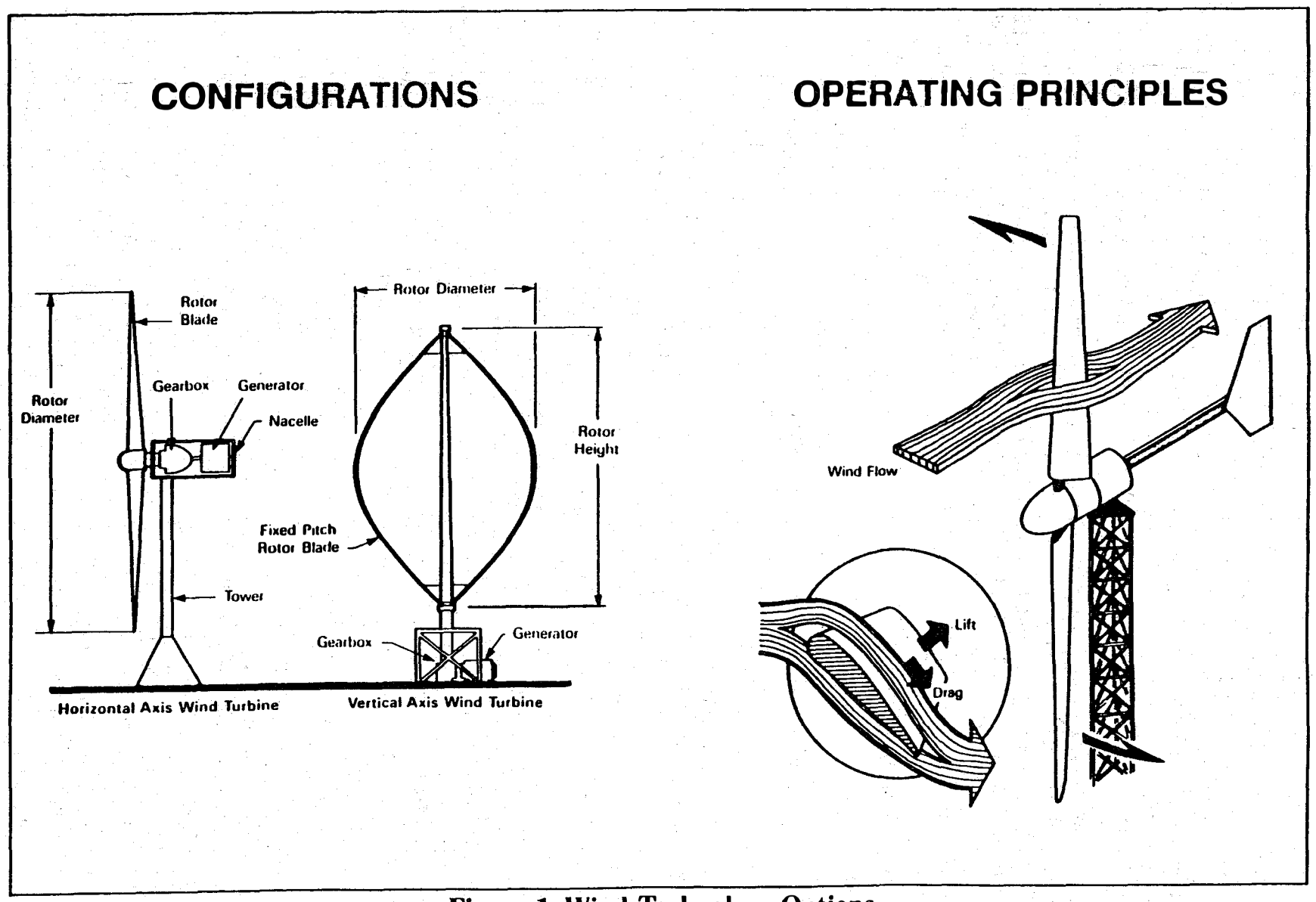


Figure 1. Wind Technology Options

or interconnection equipment.

There are two basic technical approaches to wind turbine design: horizontal-axis machines, in which the axis of the rotor's rotation is parallel to the wind stream and the ground; and vertical-axis (Darrieus) machines, in which the axis of rotation is perpendicular to the wind stream and the ground. The majority of turbines in commercial use today are of the horizontal-axis type.

Many variations in horizontal axis wind turbine configuration are possible. For example, several mechanisms are designed to keep the rotor oriented properly in the wind stream. Some machines simply have a tail vane or rudder to control the turning, or "yawing" motion; others (typically larger machines) have active motor-drive systems controlled by microprocessors. On most of the recently installed horizontal-axis machines, the blades are located on the upwind side of the tower; others are downwind. Some machines, called "fixed-pitch turbines", have blades that are fixed to the hub in a single, stationary position, thereby reducing design complexity. Another design, called "variable pitch" uses blades that can rotate around their own axis ("pitch") in order to aid in starting, stopping, and regulating power output by changing the angle at which blades cut through the air. Rotors that are attached to the hub using flexible couplings are known as "teetered rotors" and can help reduce the loads experienced by the turbine, acting much like shock absorbers on an automobile.

1.2 Technology Applications/Users

The major application for wind energy is in the bulk power market, with units owned by either the utility or an independent power producer. Other applications include remote power production for communications stations, village electrification, diesel fuel augmentation, and irrigation. These latter applications may have a mix of private and government ownership.

In the near-term, some of the best markets for wind energy systems are in remote locations where diesel generators are commonly used or where the terrain is too rough or isolated for reliable delivery of diesel fuel. Used in conjunction with other renewable technologies or batteries, this application should continue to provide a market for small, high reliability wind turbines. Two additional markets in which WECS are currently competitive are small, local grid applications that utilize diesel-fired generation, and some water pumping applications. Both markets are expected to grow in response to the large projected increase in electric capacity and water supply required by developing countries. International donor agencies and governments will be a major source of funding for projects in these countries.

Wind energy for bulk power will first compete primarily as a fuel-displacing technology, with wind plants in some geographic areas receiving partial value from utilities for firm capacity. This "capacity credit" is based on the hourly correspondence between wind plant power output and utility loads. Market penetration will most likely grow slowly for the next decade. Except for very high wind speed sites or favorable buy-back rate contracts, some of which are still available in California, WECS are not currently competitive as fuel savers for bulk power generation markets. Several factors may combine to increase penetration into the bulk power market. First, as is occurring in several European countries, national planners are creating markets to accelerate the implementation of WECS for bulk power applications. This creates an initial demand and enables manufacturers to implement incremental design improvements. Second, external environmental costs may start to be included in fossil fuels costs, causing

increased justification for and emphasis on utilizing technologies that do not contribute to global pollution. Finally unforseen near-term increases in fossil fuel prices, especially oil and gas, could accelerate market penetration.

In the longer term, as oil and gas prices rise, wind energy will become competitive in the more widespread areas characterized by lower wind power classes. In addition, the ability to predict winds on a relatively longer time scales will improve, potentially allowing wind energy plants to be operated with greater certainty, thereby increasing their value to utilities. Due to the regional variation in the amount and levels of the wind power resource, and due to the other regional variations determining the competitive market for power generation, wind technology will achieve different levels of regional market penetration. Operating requirements of the electric system will begin to constrain wind energy penetration at certain levels of total installed wind capacity. These levels have been estimated to be in the range of 5 to 20 percent of the total electric system capacity [1].

All major wind plants currently installed in the U.S. are owned by independent power producers. However, these take several forms. The third party, limited partnership projects, popular in the early and mid 1980s, have given way to project financing from institutional investors, wind energy companies, and electric utility subsidiaries. It is expected that in the near-term, most projects will also be owned and operated by independent power producers, unless regulatory changes encourage utility involvement.

1.3 Resource/Land Use

Wind energy resources are widespread in both the continental U.S., and Hawaii and Alaska. The wind resource is very large with an accessible resource base of 29 billion barrels of oil equivalent per year (nearly 170 Quadrillion BTU) [2]. The resource is characterized by wind power density classes, ranging from class 1 (the lowest) to class 7 (the highest), where each class represents a range of wind power densities and associated average annual wind speeds. As shown in figure 2, good wind resources (class 4 -- approximately 13 mph annual average wind speeds -- and higher) are available in most regions of the country, with only the Southeast and East Central regions without significant resources [3]. Wind speed is an extremely important measure of the potential for wind energy conversion because the power in the wind increases as the cube of the wind speed.

Given the nature of the resource, the annual energy generated from the wind can be predicted with some certainty, on a long term basis, but the ability to schedule and dispatch wind power is somewhat limited. In advantageous locations such as Hawaii, the trade winds are steady and turbines can operate continuously, while in others with winds driven by pressure differentials associated with frontal systems, the winds are high when the front is passing and low thereafter. In the California passes, wind turbines are driven by the inrush of cooler coastal air as the mountain desert air is warmed and rises. The winds are quite predictable in the summer, and largely follow the daily electric utility load cycle with some time shift. Thus it is possible for wind plants to get some "capacity credit" in California. A region with a large amount of wind in the moderate power-class range (classes 3 and 4, corresponding to 13-14 mph average annual wind speeds) is the Great Plains states. As shown in figure 2, such moderate resources exist from Montana as far South as Texas, and as far east as Arkansas and Minnesota. In any region, specific locations can benefit from local terrain features that enhance air flow by channeling it

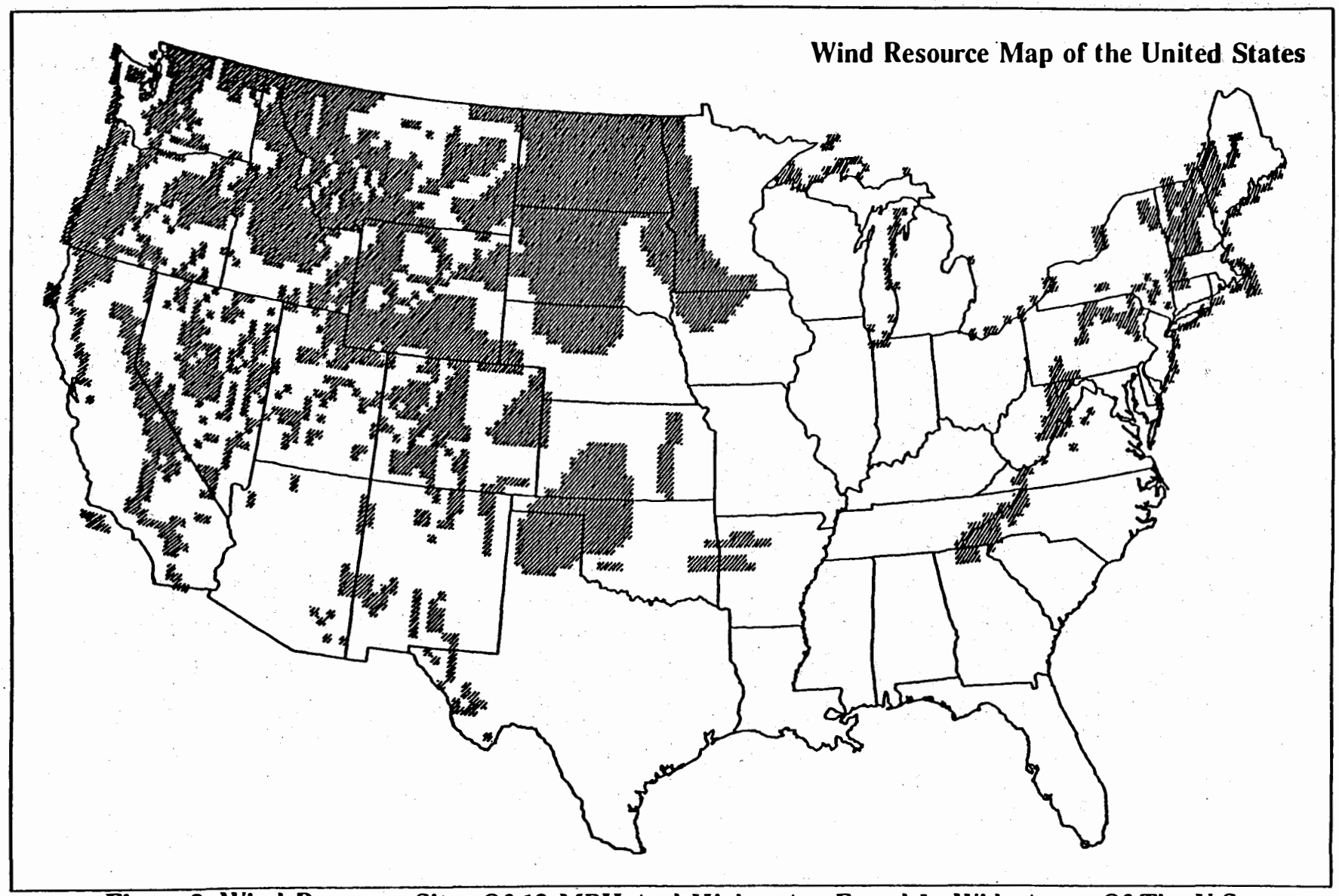


Figure 2. Wind Resource Sites Of 13 MPH And Higher Are Found In Wide Areas Of The U.S.

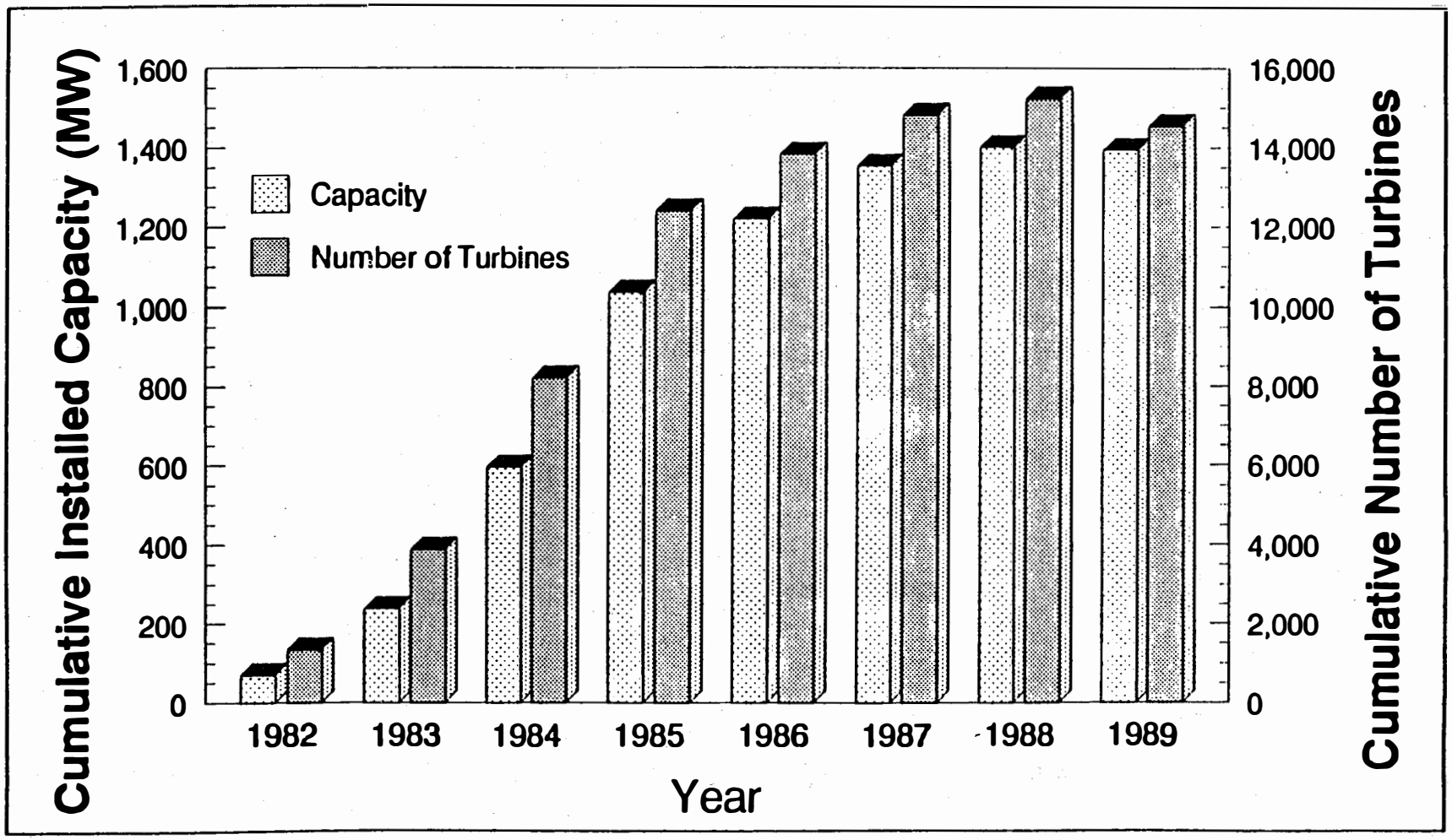
through smaller areas, thus increasing its velocity and resulting power density.

Although the better wind class sites (class 5 and higher) present opportunities for market penetration of wind energy systems in the near-to-mid term, over the long-term, class 4 resources must be utilized for wind-generated electricity to be broadly economically competitive with other forms of electrical generation over large areas of the U.S.. A preliminary analysis by Pacific Northwest Laboratories has indicated that the amount of available land exhibiting power class 4 or higher (land with no restrictions on wind energy development such as urban areas, park land, bodies of water, etc.) is approximately 7 percent of the contiguous U.S., or nearly 600,000 square kilometers. The amount of available land with power class 5 or higher falls to approximately 1 percent of total land area, or nearly 80,000 square kilometers [4]. Reference 1 calculates these estimates more conservatively, arriving at nearly 317,000 square kilometers available in classes 4-7. Using very conservative assumptions of 13 mph average annual wind speed in all areas and a 10 diameter-by-10 diameter spacing of turbines, these land areas equate to approximately 600-1,800 GW of installed wind capacity, which is far more than NES market penetration estimates (less than 100 GW). Thus, market penetration should not be constrained nationally by resource availability. Using either the 10-by-10 spacing, or a less conservative 5-by-10 diameter spacing equates to 3-10 MW of installed capacity per square kilometer. However, it is important to note that land does not have to be purchased and dedicated only for wind energy production. Leases are quite common where co-uses such as livestock grazing reduce the cost to the wind plant owner while increasing the land value to the land owner. Another possibility is to utilize former agricultural lands designated under the soil conservation program to enhance the fixed per-acre revenues allowed by the government.

1.4 Industry Status

Between 1981 and 1985, the U.S. wind energy industry experienced rapid growth due to a combination of favorable utility contracts, government tax credits, and available wind resource sites. However, a severe consolidation has occurred since the industry's peak in 1985. Currently, there are 3 wind turbine manufacturers producing machines domestically, down from over fifty in 1985. Only one of these has had sales of intermediate-size (100 Kw to 1 MW) turbines during the past three years. The other two companies compete in the small, high reliability, remote system market. Several companies in addition to the three mentioned previously are actively pursuing new designs reflecting incremental improvements to existing technology. Some firms are developing joint ventures with European companies. In addition, a few companies have shifted to an emphasis on service and turbine refurbishment. Most of the materials necessary for wind turbines are commonly available, and as such, do not present a likely obstacle to future industry growth. It is possible that, given certain market conditions, former manufacturers who are still in other areas of business may rejoin the industry.

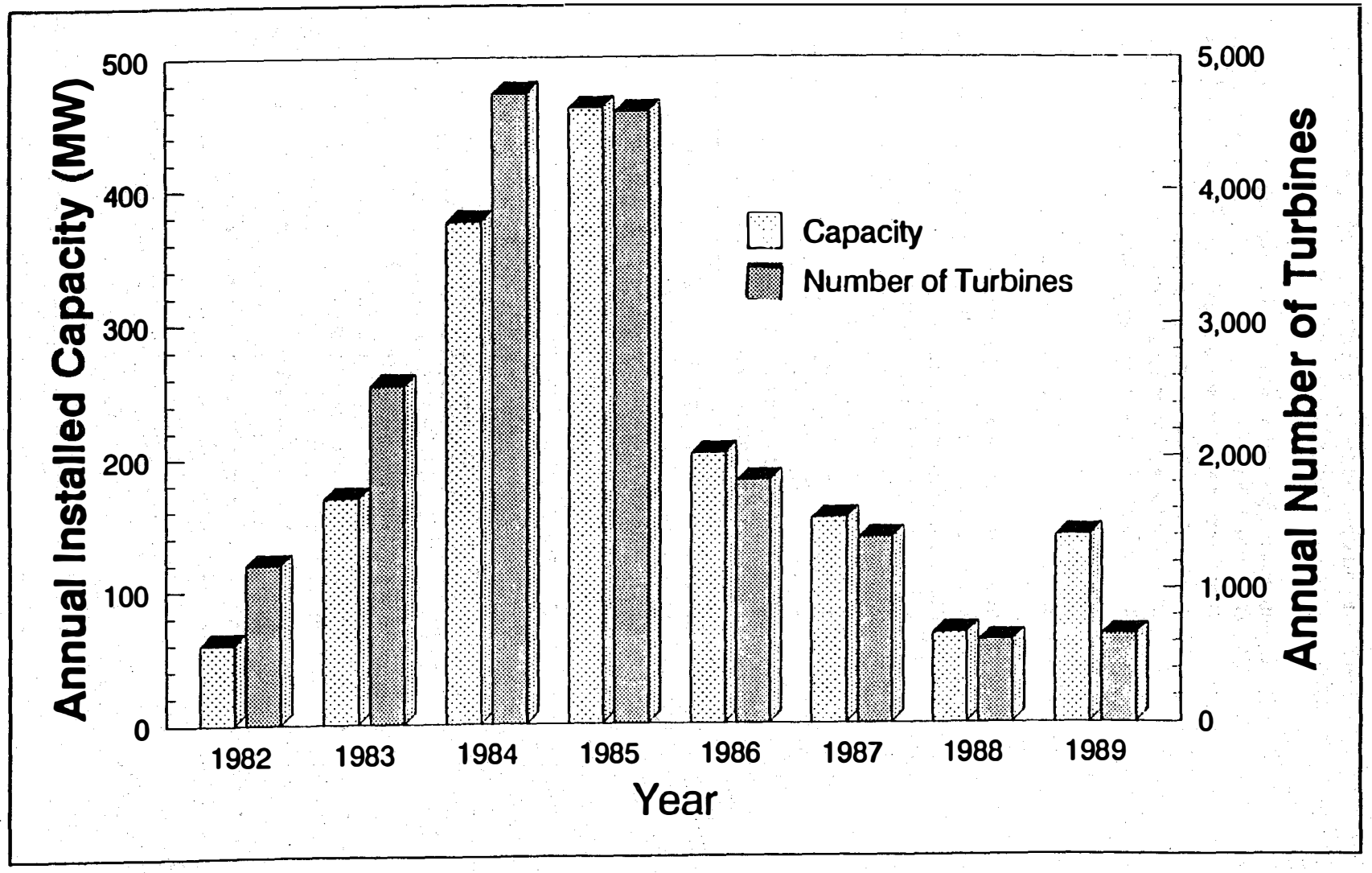
As of 1989, there were over 14,000 wind turbines installed in California wind plants representing about 1400 MW of on-line capacity. Figure 3 displays the growth of these installations since 1982. In 1989, these turbines generated 2.1 billion Kwh of electricity or about 1% of total California generation. Figure 4 shows that annual California wind turbine installations dropped continuously between 1985 and 1988 due largely to the expiration of wind energy tax credits and the recent industry focus on refurbishing older machines that have experienced reliability problems. In 1989, 660 turbines, representing 140 MW of capacity, were installed, far below the 1985 peak year capacity installation of 4590 turbines and 462 MW of capacity. The number of



Note: Numbers include replacement/retirement of turbines.
1989 includes 200 MW, approximately 1700 turbines retired.

Source: American Wind Energy Association

Figure 3. The U.S. Already Has A Significant Wind Capacity Connected To The Electric Grid



Note: Numbers include replaced/retired turbines

Figure 4. Annual Installed Wind Capacity

new turbines installed in 1989 remained nearly constant from the year before, however the installed capacity increased, reflecting the trend toward larger turbines.

Wind plant operators hold several hundred megawatts of additional utility power purchase contracts with high avoided cost payment schedules, which will expire shortly, suggesting that turbine installations may increase over the next year. Once these existing contracts expire, wind energy will have to compete at cost equivalence with conventional generation alternatives. Without continued technological advancement to resolve reliability issues and achieve higher performance and lower costs, the number of new wind turbine installations will most likely decline further.

1.5 Market Acceptance and Experience

Considerable operating experience has been gained over the last decade from wind plants, primarily in California and Hawaii. Large advances have been made in the ability to operate and maintain turbines, both on a single-unit level as well as part of an entire wind plant. Additionally, the "laboratory" provided by the extensive deployment of commercial turbines has resulted in improvements in turbine engineering and design, elimination of bad designs, and increased ability to properly site and install turbines in cost-effective ways. The fact that financing for wind energy projects has shifted from third party limited partnership investors concerned chiefly with large initial payback and higher financial returns associated with tax credits, to institutional investors with lower required rates of return reflects the trend towards market acceptance of the technology. The gains in performance and cost reduction made by the industry are the prime reason for growing market acceptance. Still, uncertainty exists in the minds of many would-be investors and utilities. Private developers have indicated that their projects include a premium that reflects the cost of guaranteeing certain levels of reliability comparable to more mature generation technologies.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

The wind energy technology section of the Renewable Energy Technology Characterizations presents estimates of several figures of merit to characterize the projected progress of wind technology. Choosing one single measure of progress is difficult for several reasons. One of the most often cited figures of merit is the levelized cost of energy, or COE, in units of $/kWh. Since COE estimates combine initial cost, annual O&M cost and replacement costs with annual energy capture (see reference 4), the resulting value is too complex to use as the basis for a descriptive rationale. For this reason, the following discussion presents COE which can be used to describe improvements in cost and performance. All figures of merit listed below are found in the wind energy technology characterizations. However, when comparing to other technologies, the key figure to use to characterize cost is $/kW, and the key figure to characterize performance is capacity factor.

Key Figures of Merit:

- Installed cost per square meter of swept area ($/m^2) - Despite differences in how

turbines are rated, the aspect that always remains consistent from one turbine to another is the energy contained in the incoming wind. In order to compare wind turbines against each other, we can express their initial capital cost in terms of dollars-per-square meter of rotor area. It is impossible to use this figure for comparison with other technologies, however, when used in conjunction with the next figure of merit, a comparison can be made.

- Energy output per square meter of swept area ($kWh/m^2/yr$) - Like cost, wind turbine performance (energy output) can also be expressed per unit of swept rotor area in order to provide a consistent basis of comparison between turbines. This figure of merit necessarily requires an assumption about the available resource.

- Installed cost per unit of annual energy ($/kWh/yr) - Installed cost per annual kWh produced combines cost and energy production into a single figure while eliminating assumptions concerning choice of financial parameters and the time-value of money. However, it ignores the annual cost for operation and maintenance. This figure is can be calculated from the previous two figures.

- Installed cost per unit of design capacity ($/kW) - Wind energy systems come in different sizes and ratings. One system may achieve its rated capacity at a certain wind speed, while another may require a totally different wind speed to achieve its rated capacity. Also, designers are free to choose between different-size generators for a wind turbine with any given-size rotor blade. For these reasons, two different systems with the same rating may actually produce different amounts of energy when placed at the same site. Because of these difficulties, using the rated capacity for comparing different turbines against each other another does not provide a consistent basis for comparison. However, because cost-per-unit kW is a well-known way to express cost, it is retained as one figure of merit to be used to compare wind energy systems to other generation technologies.

- Capacity factor (%) - The capacity factor is the amount of energy that the system produces at a particular site as a percentage of the total amount that it would produce if it operated at rated capacity during the entire year. This figure can be used to calculate annual energy production using a similar method as for other technologies.

- System average annual efficiency (%) - The system average annual efficiency is the percentage of energy extracted by the turbine from the wind passing through the rotor. It is a good technical measure to use in tracking performance trends.

- Operation and Maintenance Cost (cents/kWh) - O&M accounts for all cost incurred for regular, or scheduled, operation and maintenance of the wind plant facility, including labor and parts.

2.2 Historical Technology Trends/Current Status

Over the last several years, wind turbines have experienced the largest deployment in clusters of so-called "windfarms", now commonly referred to as "wind plants". Individual turbine sizes for wind plants have ranged from 18 kW to 600 kW, however the majority of turbines installed to date have been in the 100 kW size range. Most recently, turbine installations have been in the larger size range above 200 kW. Figure 5 shows the trend towards larger machines.

Spurred by booming market activity and federal and private R&D, wind plant costs, as shown on figure 6, have fallen by a factor of 4 from 1500-2000 $\$/m^2$ in 1980 to 400-500 $\$/m^2$ in 1989. This equates to approximately 3000-4000 $/kW in 1980 and 1000-1200 $/kW in 1989. Figure 6 also shows that, during the same period, net annual energy has increased by a factor of more than two from 200-400 kWh/m^2 to 600-800 kWh/m^2 (for 13 mph sites). Another important indicator of technical and operational advances is that the average performance of all California wind plants, shown in figure 7 as annual kWh per unit installed capacity, has improved annually since the early 1980s. This industry-wide improvement can be attributed to better performing turbines being brought on-line in the latter years, better turbine availability through improved operation and maintenance, and retirement of the poorly designed turbines installed during the first half of the decade. DOE-sponsored R&D has also played a key role in this increase in energy capture. Designers are using more efficient system configurations, as well as better techniques for siting both wind plants and individual turbines within the plants.

Figure 8 shows that availability has increased from as low as 60 percent in 1980 to over 95 percent for the best current plants. Scheduled O&M costs have fallen nearly four-fold, from approximately 4 cents/kWh to 1-1.5 cents/kWh. The cost of unscheduled repairs or replacements for components such as blades, drive trains, and yawing mechanisms is estimated to be about half of scheduled O&M costs. Figure 9 shows that COE has fallen from 25-30 cents/kWh to 7-10 cents/kWh at 13 mph sites (however, this does not include the cost of long-term guarantees often required by investors because of the perceived risk of wind projects compared to more mature technologies). A complete assessment of current wind energy technology status, including a description and listing of key cost/performance parameters is located in reference 5.

3.0 COST/PERFORMANCE PROJECTIONS

The improvements in wind energy technology cost and performance projected in the Wind (Horizontal Axis) section of Renewable Energy Technology Characterizations are plotted in figure 10 for both a base case and an accelerated R&D case. The base case scenario assumes that the annual funding level remains at the FY90 level over the entire planning horizon. The accelerated R&D scenario assumes an increase by a factor of 2 or 3 in funding level compared to the base case. These scenarios are fully described in sections 3.1 and 3.2 of this paper.

The basic figure of merit used to compare wind energy with other technologies in the NES framework is the levelized cost of electricity (COE). Projections of the COE values are plotted in figures 11 and 12 for the three different resource levels of 13 mph, 14 mph, and 16 mph annual average wind speed, for the base and the accelerated R&D cases, respectively. The levels also are used to define the wind resource on a regional basis in the one page summary

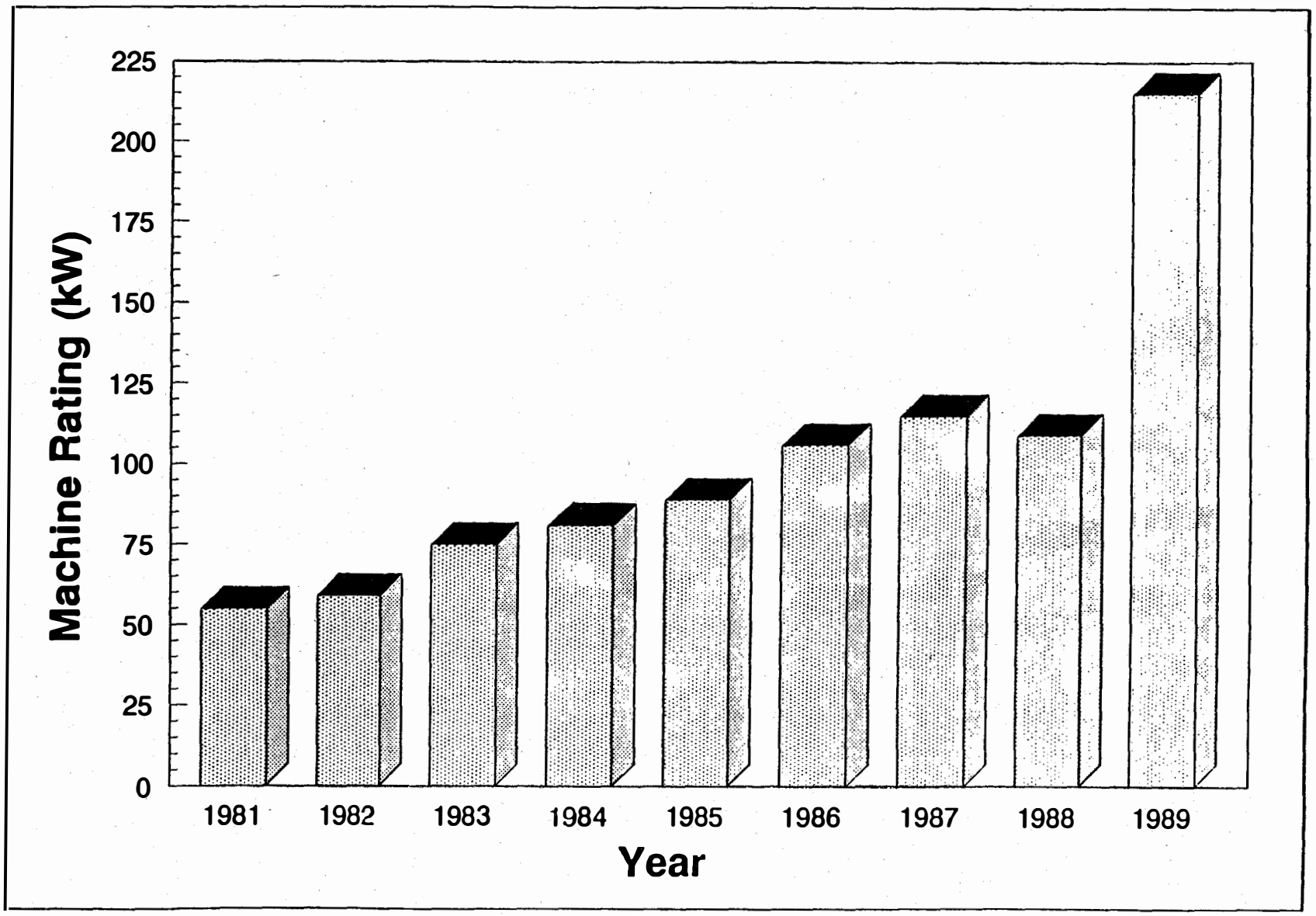


Figure 5. Average Machine Size Shipped

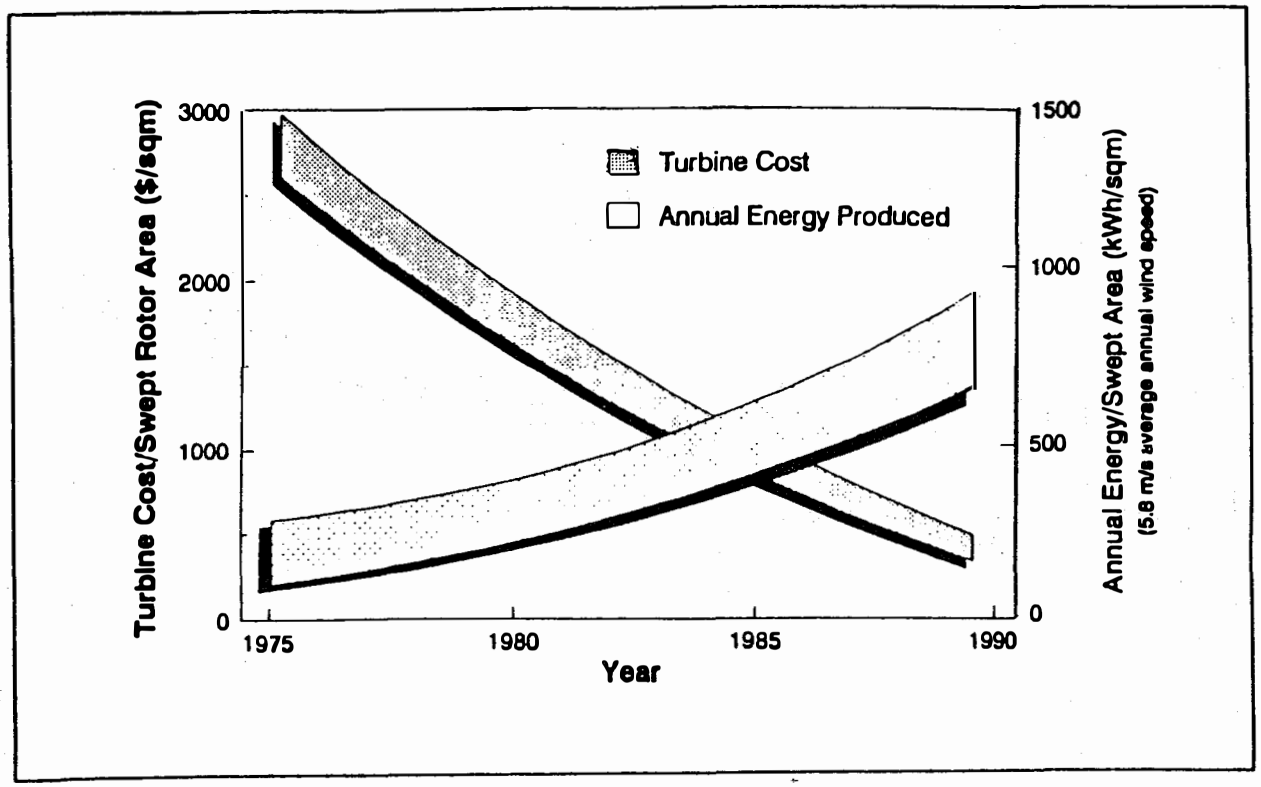


Figure 6. Wind System Figures of Merit

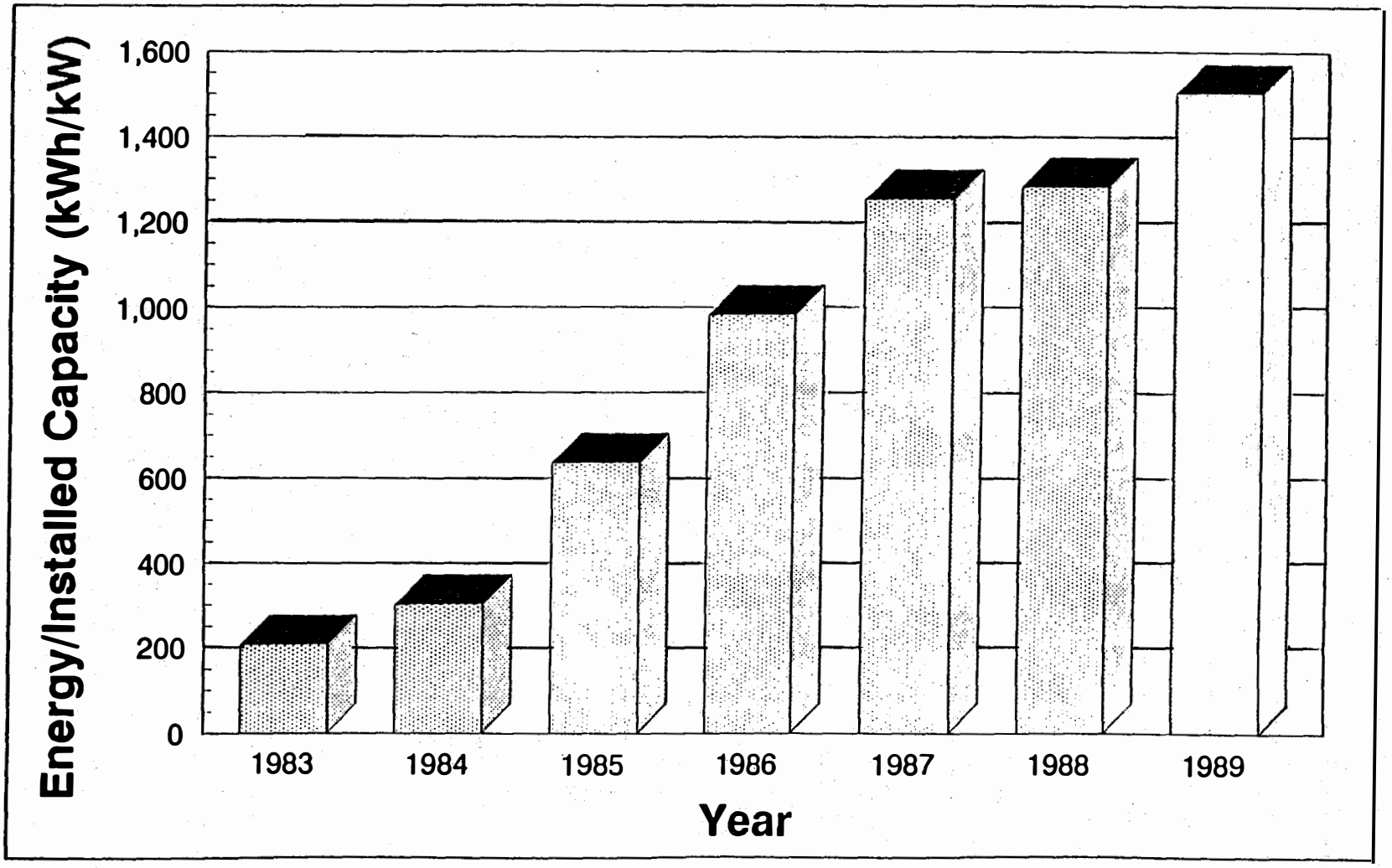
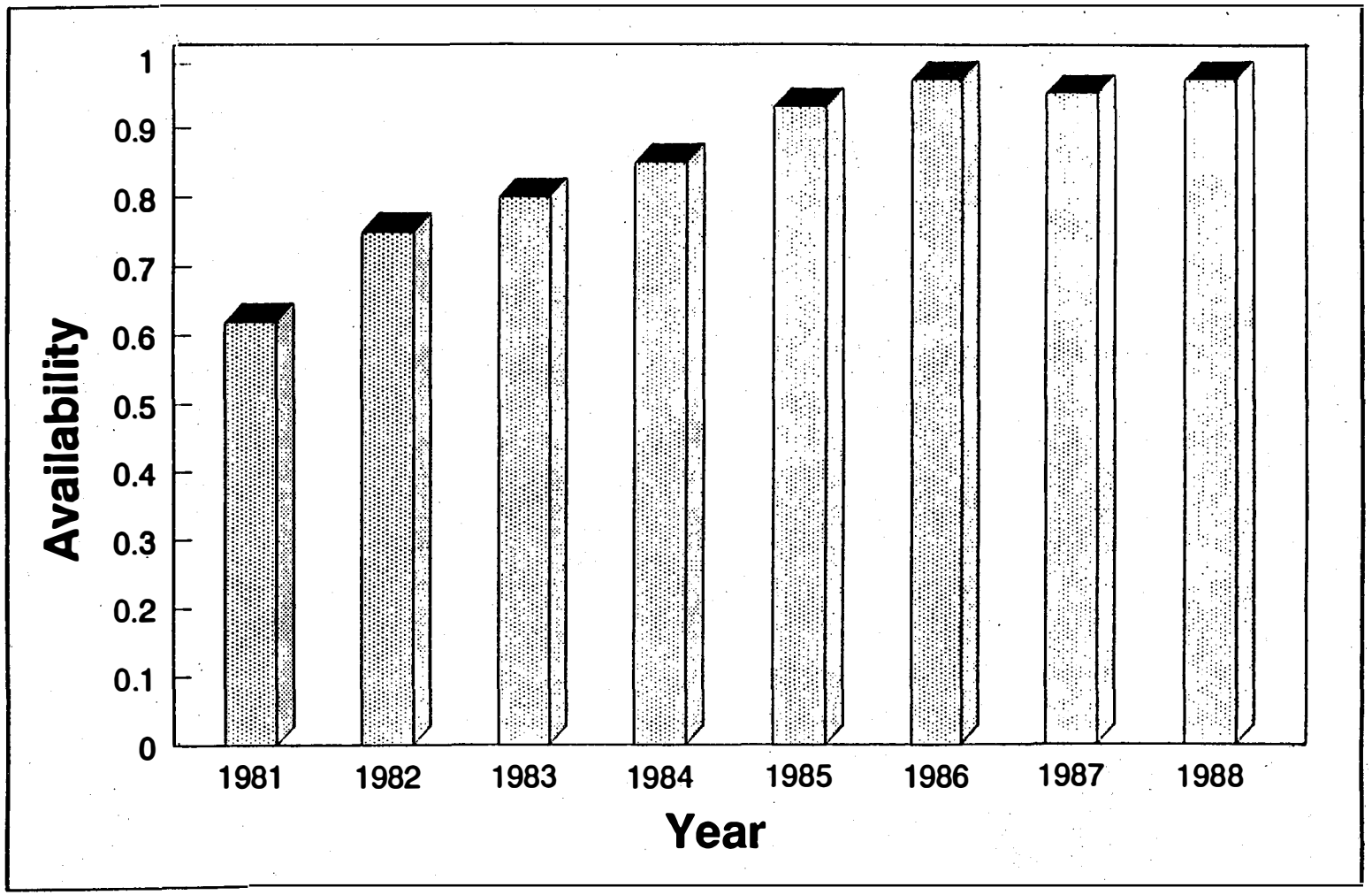


Figure 7. Wind Turbine Production Efficiency Improvements



Reference: R. Lynette

Figure 8. Availability For The Most Reliable Installations Has Increased

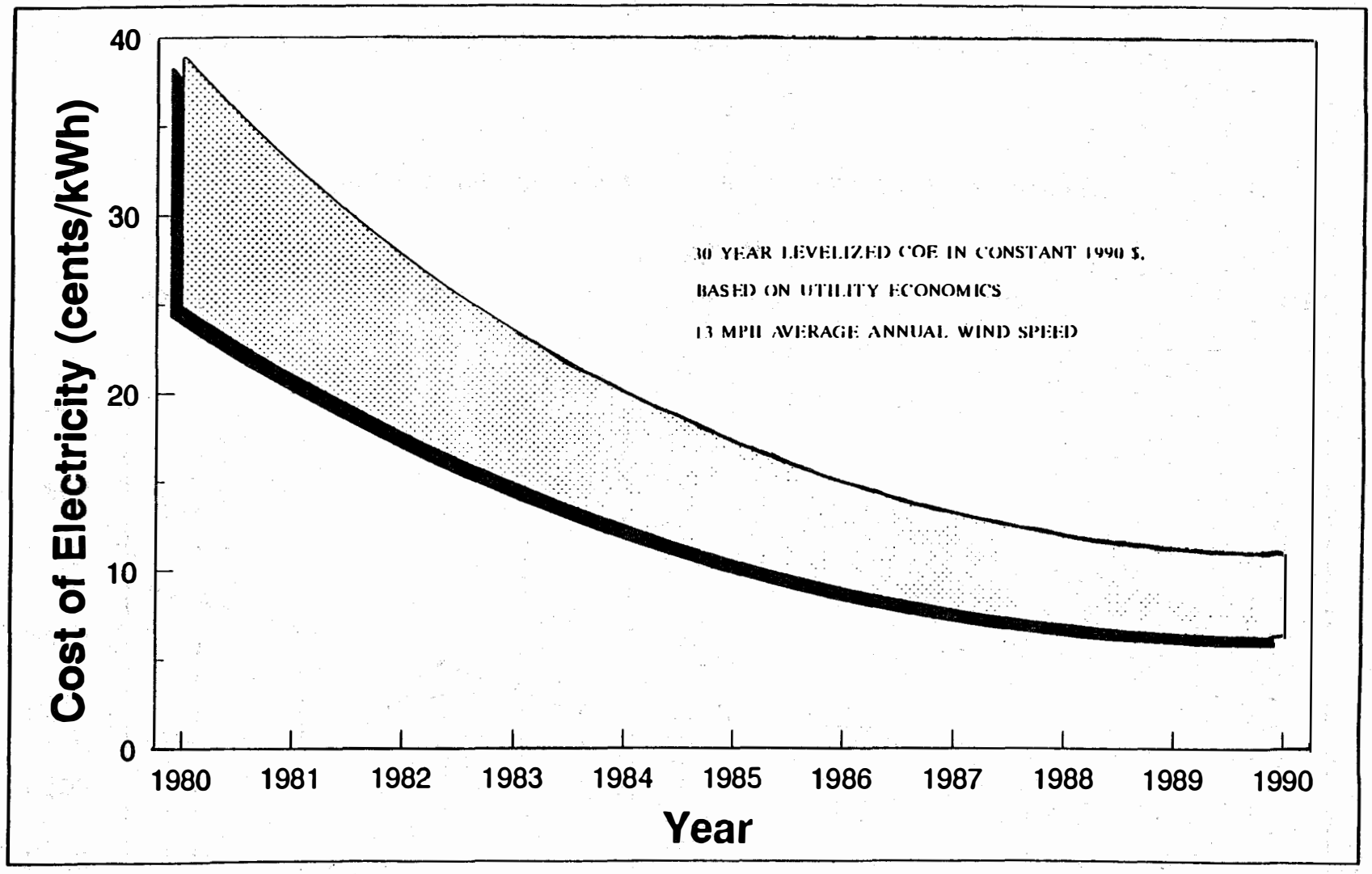


Figure 9. The Cost Of Electricity From Wind Turbines Has Declined Dramatically Since 1980

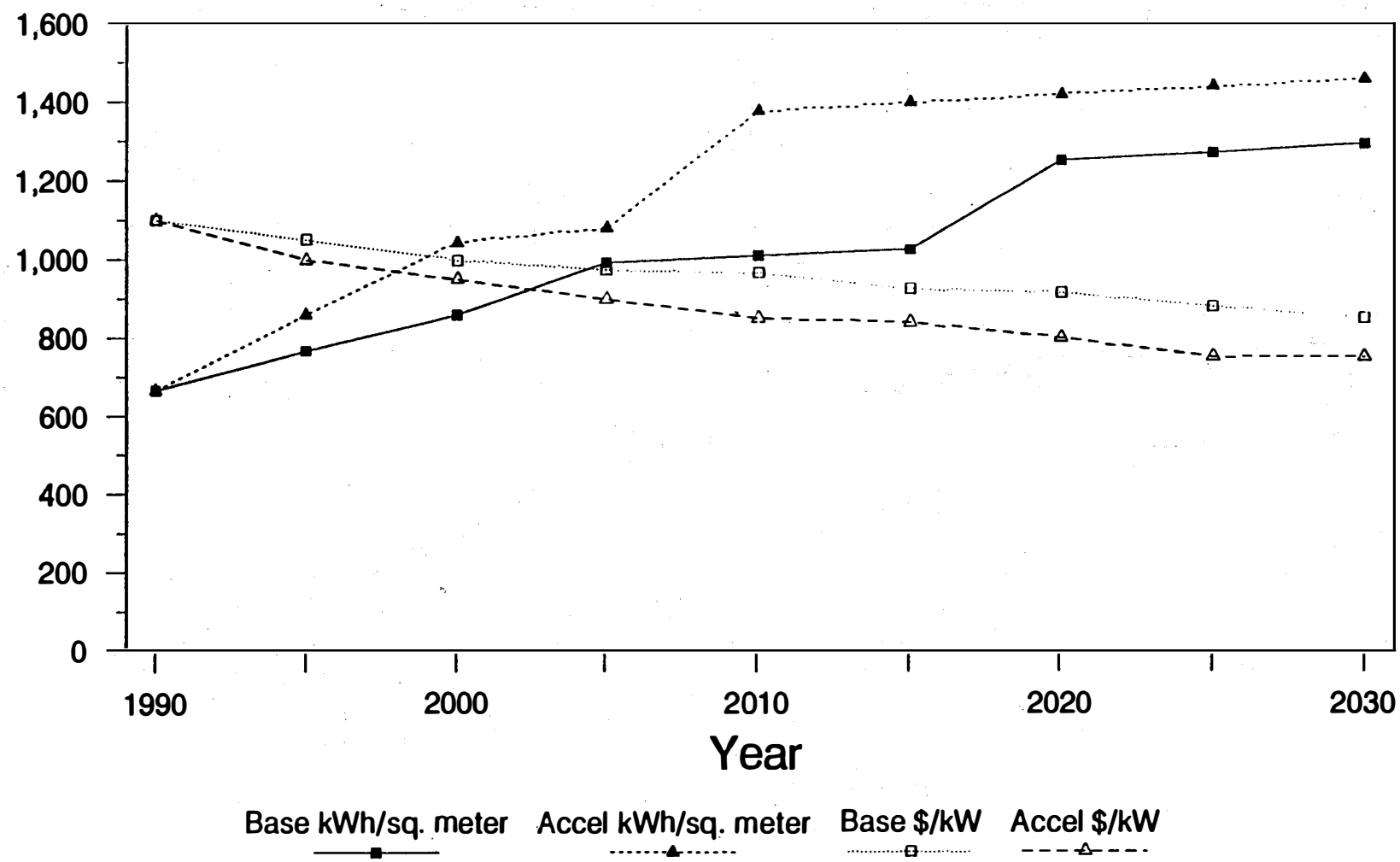


Figure 10. Energy And Cost - Base Case Vs. Accelerated Case at 13 mph

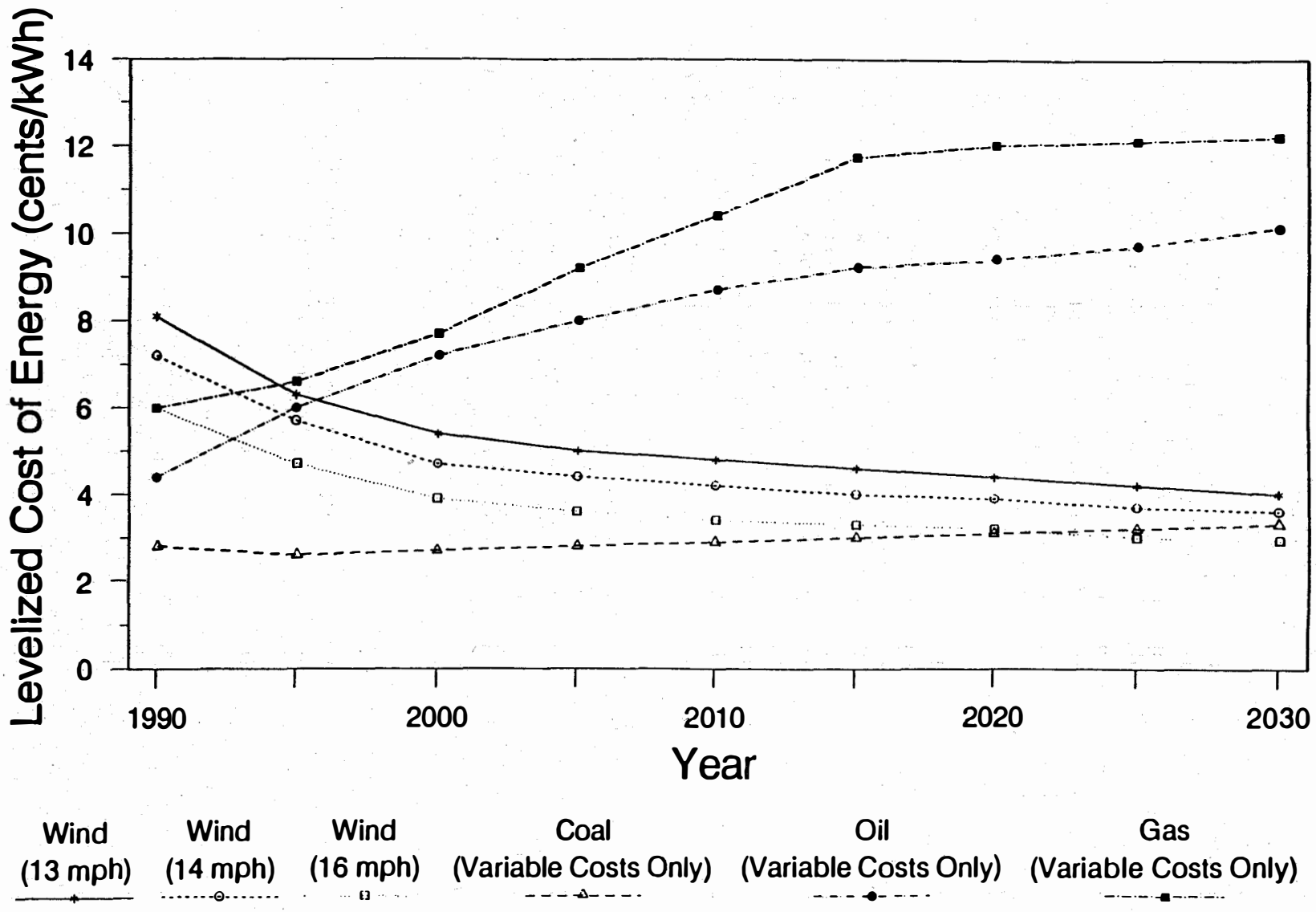


Figure 11. Intermittent Renewable Technologies - Base Case

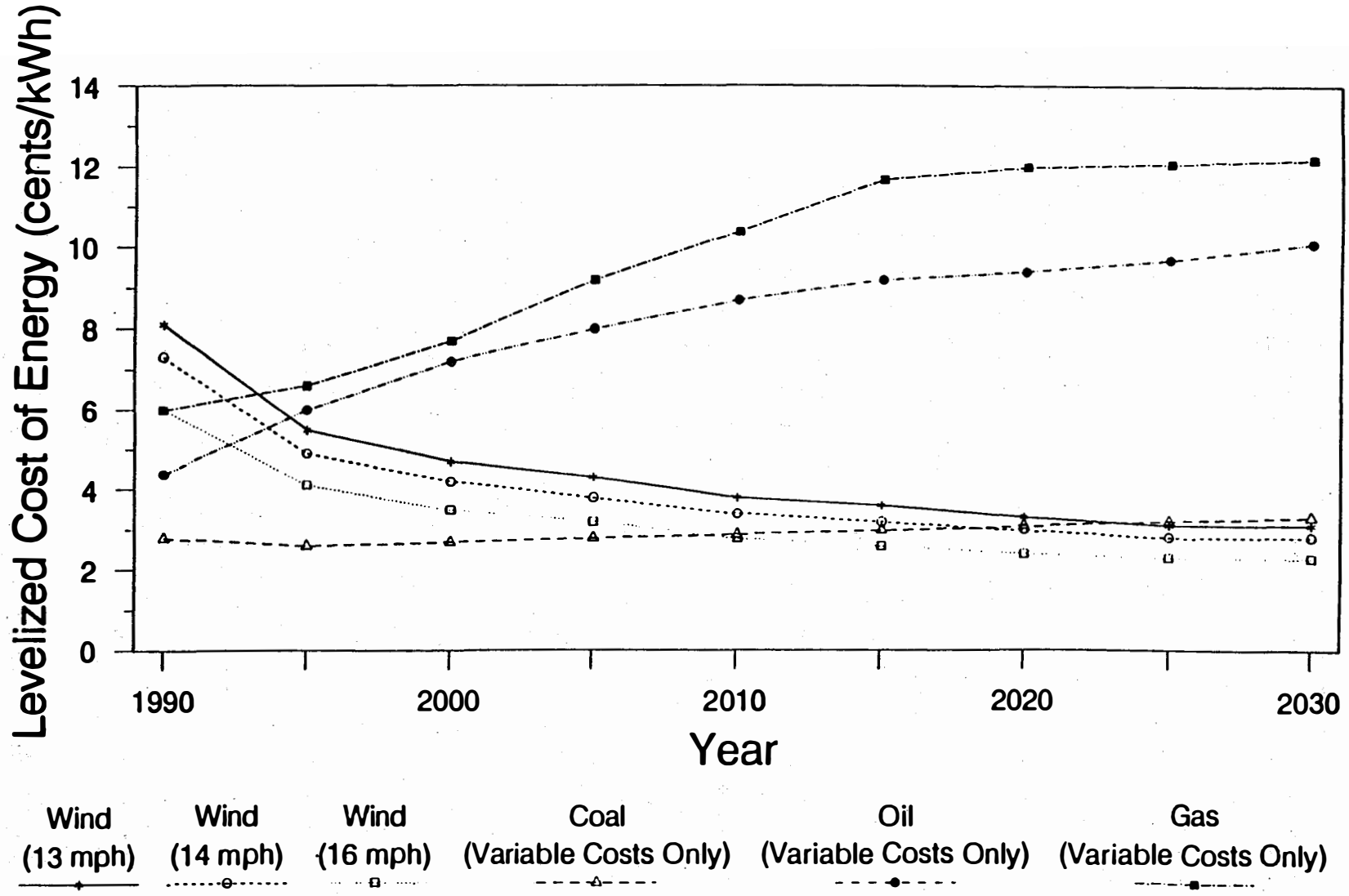


Figure 12. Intermittent Renewable Technologies - Accelerated Funding Case

sheet preceding the detailed characterization for each wind energy technology in Renewable Energy Technology Characterizations. Figures 11 and 12 are taken from pages __ and __, respectively, in the characterization report. The COE for wind energy is compared to the variable operating costs (fuel plus O&M) for coal, oil, and natural gas. It should be noted that no improvements in conventional technologies are included in these graphs.

For both funding scenarios, market penetration will occur first for sites with exceptional wind resources, or relatively high percentage of oil and/or natural gas in the fuel mix. Note that figures 10 through 12 represent technology that is available for commercialization. However, because of the time lag associated with commercializing a product, market penetration from that technology will not show up until the following time period (the NES analysis assumes a 5 year time period).

Researchers can provide the analytical justification for the values of cost/performance advances with a relatively high degree of confidence (see Section 4.0). However, projecting their timing, or even the probability of their occurrence, depends on assumptions concerning the level of R&D effort. Therefore, before detailing the technical reasoning used to form the cost/performance projections, the base case and the accelerated funding scenarios must be defined.

3.1 Base Case Funding Scenario

The base case funding scenario assumes that the FY 90 annual funding level of $8.6 million remains constant over the planning horizon. The technology improvements projected under this scenario are believed to be achievable at that funding level. Under the base case funding scenario, the program will have to balance the longer-term benefits of a basic science research program with the need to perform applied research toward advanced turbine technology.

3.1.1 Research Activities

A strong basic science research base is vital to lead the industry past the next round of improvements towards the innovative designs that will be required for competitiveness in the post-2000 timeframe. This activity will be continued under base case funding. However, because of its desire to support industry's near- and mid-term needs, the program has taken the first steps toward an advanced turbine project and has recently negotiated contracts for several Conceptual Design Studies of advanced wind turbines. These designs, when completed, could form the basis for future advanced turbine development activities.

The program and industry believe that timely introduction of "advanced turbine technology" is crucial to U.S. industry in terms of meeting a utility market "window of opportunity" that is expected in the 1995-2005 timeframe. If the program were to proceed with the next step in this advanced turbine activity, detailed design and fabrication, the basic science program would come under intense budget pressure. For that reason, the level funding scenario assumes that advance turbine development activities would be limited to a single design and would likely be spread out over a number of years. Technical risk would be much higher than that of multiple full-scale development projects (which is included in the Accelerated R&D scenario) as different design approaches would not be investigated. Furthermore, the benefits from competition in the marketplace that come from having multiple competitive designs available would never

materialize.

3.1.2 Base Case Technology Development Scenario

Table 1 summarizes the projected technology path for the base case scenario. Additional information detailing the rationale for each technology stage can be found in section 4. Under base case assumption, the pace of improvement to the 1995 turbine is slowed (compared to the accelerated case) due in part to the weak state of U.S. companies, and the relatively unfavorable image of the industry from problems with machines from the first half of the 1980s. A single advanced wind turbine, scaled up to a larger size, will begin to penetrate the market by the year 2005. The 2005 design will include incremental improvements to current technology, and will be

Table 1. Projected Technology Path for Base Case Scenario

Year	Turbine Rated Capacity (kW)	Turbine Diameter (meters)	COE at 13mph (cents/kWh)	Technology Description
1990	100	18.3	8.1	Composite of 6 commercial turbines.
1995	300	33.0	6.3	Scale up to U.S. WP 33-300.
2000	300	33.0	5.4	Partial "Advanced" design but still 300 kW.
2005	500	40.0	5.0	Completed "Advanced Turbine" design.
2010	500	40.0	4.8	Incremental design improvements to
2015	500	40.0	4.6	"Advanced turbine".
2020	1000	51.7	4.4	Scale up to optimum size.
2025	1000	51.7	4.2	Incremental design improvements to
2030	1000	51.7	4.0	optimum size.

able to deliver electricity at 5 cents/kWh at a 13 mph wind site. Turbine erection will be inexpensive (without a crane or using only a small crane), and routine maintenance will be on the ground, which will reduce O&M costs. Advanced features of the turbine are detailed in section 4 of this paper. A detailed breakdown of costs and turbine capacity factors for the base case scenario is given in Table 2.

After this major development effort, further advances to the technology will be small, most likely taking advantage of economies of scale related to larger rotors, eventually reaching an optimum size (shown as 1 MW in the characterization document) by the year 2020. Although only one turbine configuration is shown as this "optimum" design, it is likely that, in reality, there will be different "optimum" designs, depending on the local operating characteristics such as wind speed and turbulence level, terrain, climate, etc. Since the basic sciences portion of the Program will have to be cut back in the 1990s in order to support the advanced turbine development program, it is likely that the COE that will be achieved by 2030 under this scenario will approach only 4 cents/kWh (in 1989 dollars, for a 13 mph site), which will not be competitive with baseload energy (coal), except under special circumstances such as excellent wind sites, or favorable avoided costs from utilities.

Table 2. Cost and Performance Details

CAPITAL COSTS ($M)										
Major Components		1990	1995	2000	2005	2010	2015	2020	2025	2030
Rotor		14.7	13.5	12.3	11.9	11.5	11.2	11.0	10.8	10.7
Tower		5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
Generator		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Electrical		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Transmission/ Drive Train		6.3	6.0	5.6	5.5	5.4	4.8	4.7	4.3	4.1
Nacelle		2.8	2.7	2.5	2.4	2.4	2.3	2.3	2.1	2.0
Land		3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Balance of System		3.7	3.4	3.2	3.1	3.1	2.8	2.7	2.6	2.5
Total Direct Cost		43.9	42.1	40.2	39.4	38.9	37.7	37.2	36.3	35.8
Installation		7.3	7.0	6.6	6.3	6.3	5.8	5.8	5.5	4.8
Engineering Fee		3.7	3.4	3.2	3.1	3.1	2.8	2.8	2.2	1.9
Total Installed Cost		54.9	52.5	50.0	48.8	48.3	46.3	45.8	44.0	42.5
OPERATION AND MAINTENANCE COSTS										
Major Repairs ($/kW)		12.3	11.0	9.8	5.0	5.1	2.6	2.6	2.6	2.5
Routine O&M (cents/kWh)		1.0	0.9	0.8	0.7	0.7	0.7	0.7	0.7	0.7
CAPACITY FACTOR										
Regions	Avg. Wind Speed (MPH)	1990	1995	2000	2005	2010	2015	2020	2025	2030
1, 2, 5	13	20.0	25.0	29.0	29.5	30.0	30.0	30.0	30.5	31.0
6, 7, 9, 10	14	23.1	28.6	33.4	33.8	34.4	34.4	34.5	35.0	35.7
8	16	30.0	37.4	43.3	44.3	44.8	44.8	45.1	45.8	46.5

3.2 Accelerated Wind R&D Funding Scenario

The accelerated wind R&D funding scenario assumes a doubling or tripling in funding relative to the base case.

3.2.1 Research Activities

Under the accelerated scenario, R&D in the basic sciences would run concurrently with the "Advanced Turbine" development program, positioning U.S. industry to compete favorably by 2015 in large land areas, where the predominant fuel is coal. In addition, by completing the advanced turbine program by 1995, there would be a better probability of U.S industry meeting the utility market "window" in the near-to-mid-term (1990s and early 2000s). Because there is a higher probability that this market will be penetrated, the basic R&D being performed by the program could be utilized by companies with increasing field experience and capital resources. Compared to the base case scenario, this combination of private engineering knowledge and capital should result in a both an earlier scale-up to optimum size (identified as 1 MW in the technology characterizations) turbines, and utilization of more advanced design tools for those scaled-up turbines.

It is clear that the U.S wind energy manufacturing industry is in severe need of revitalization, both in terms of a broader manufacturing base, and increased market activity. Under the accelerated wind R&D funding scenario, the wind program could take a progressive role towards addressing these industry-related issues by working closely with industry in three focused areas. These areas fall under the following headings: 1) **Wind Plant R&D to Address Industry and Electric Utility Needs**, 2) **Wind Energy Technical Applications**, and 3) **Advanced Turbine Development**. A concentrated effort in these three areas, in addition to the basic research program currently being pursued by the Federal Labs, is required to address the current pressing needs of industry. The combination of these areas with the basic research program is shown graphically in Figure 13.

The objective of **Wind Plant R&D to Address Industry and Electric Utility Needs** is to enhance the performance, efficiency, and reliability of current wind plants through cooperative ventures with industry by accelerating the introduction of advanced technology for use on existing hardware. Wind plant operators face daily challenges in maintaining large numbers of turbines representative of early, and often flawed, designs. It is important to improve the performance and reliability of these highly visible turbines in order to revive the confidence and support of potential new customers and the public in general. The Wind Program would assist the industry in the design, development, testing, and analysis of solutions to current operational problems. This would in effect be an expansion of the current Cooperative Research Program, which has been very successful in addressing specific problems, including micrositing, fatigue load measurement, and poor rotor performance due to inappropriate airfoil selection. Extensive analysis sponsored by the program of over 4000 turbines in California wind plants has identified the key areas requiring better understanding. In figure 14 the annual impact on revenues is shown by basic research element, and by actual cause.

The **Wind Energy Technology Applications Program (WETAP)** would assist potential users of wind technology in the identification and development of wind systems for specific applications, and to develop methods that facilitate large-scale implementation of wind energy worldwide.

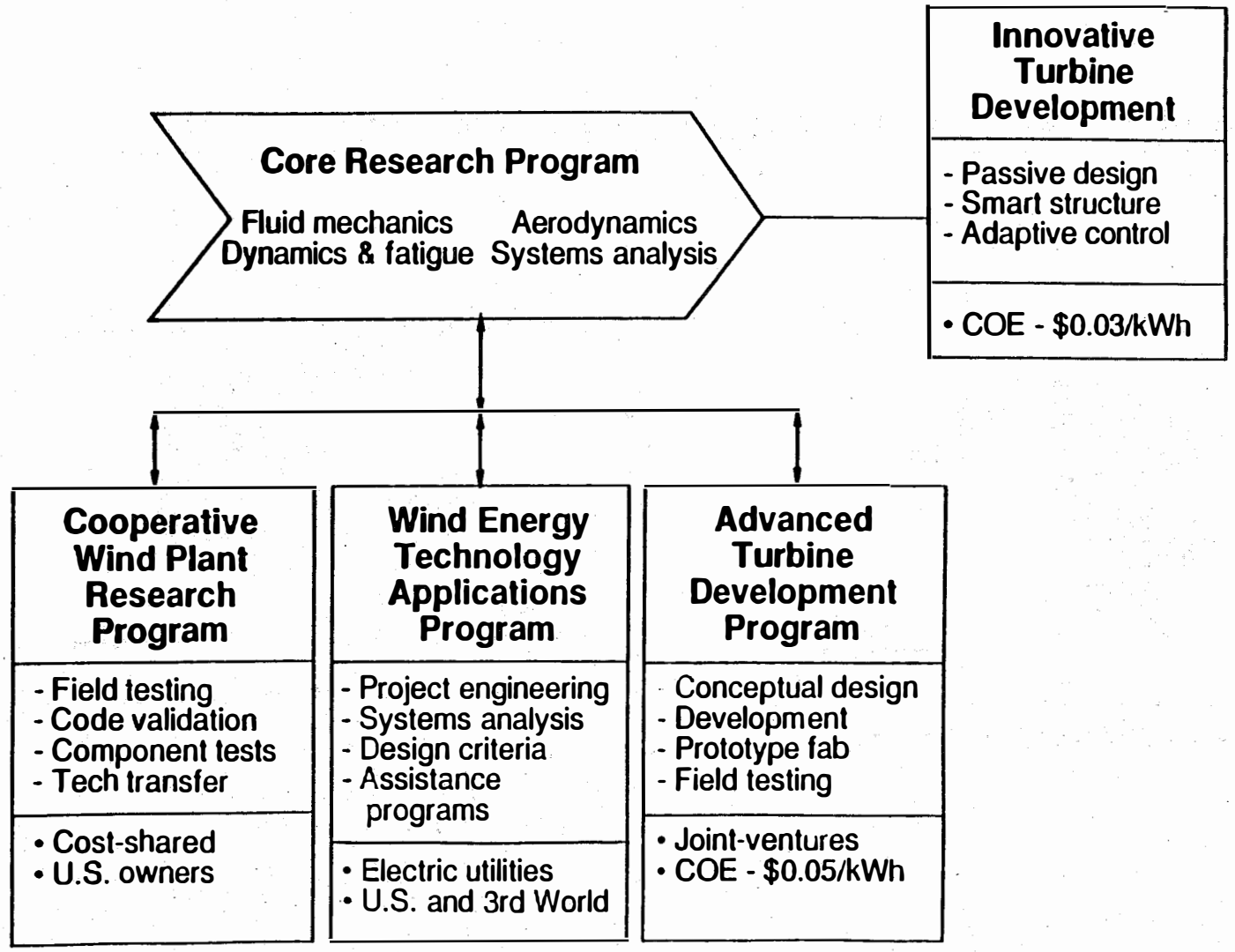
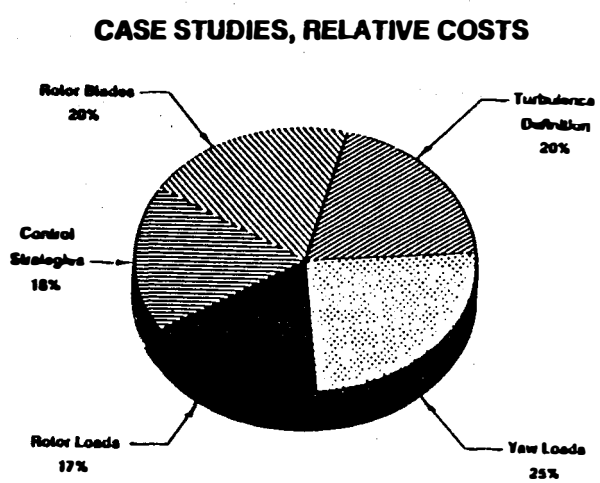


Figure 13. Wind Energy Program Structure Under Accelerated R&D Assumptions



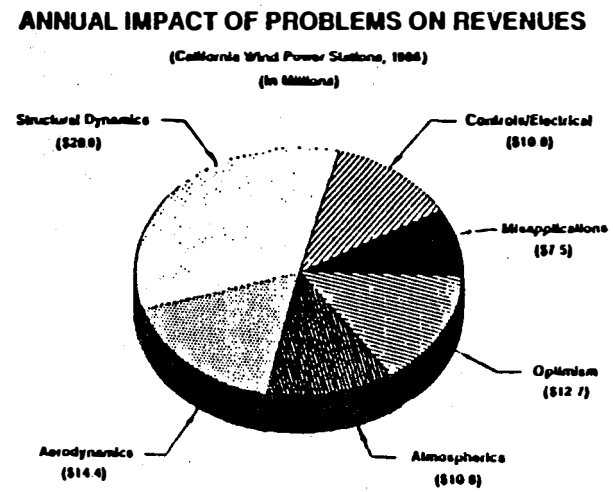


Figure 14. Field Experience Has Highlighted Areas For Research Emphasis

One function of this initiative would be to provide support to potential users of wind energy, as required for integration of the technology into existing systems. This is similar to the service that the Sandia Design Assistance Center currently provides for users of photovoltaic systems. This project will be directed mainly at U.S. utilities and independent power producers. However, support would also be provided for foreign markets to improve small systems.

Systems analysis capabilities would be enhanced so that the program can address utility concerns regarding large scale wind energy penetration, such as system stability, wind energy capacity credit, and transmission and storage. This project would also need to help industry establish system design guidelines for different applications and operating environments. Coordination of donor agencies' assistance with worldwide marketing programs and technology demonstrations would also fall under this activity.

The final, and perhaps the focal point, of the three programs is the **Advanced Turbine Development Program**. The objective of this program is to assist the U.S. industry in the design, development, fabrication, and testing of at least one advanced wind turbine concept by the mid-1990s that can complete with conventional electric generation at $0.05/kWh. As mentioned previously, it is essential for the revitalization of the wind industry to proceed along this development path as quickly as possible, in order to compete with foreign designs and have a successful product for the utility market. Joint ventures may be partially funded by the Renewable Energy and Energy Efficiency Technology Act of 1989 (P.L. 101-218), but this funding alone is insufficient to complete the job.

3.2.2 Accelerated R&D Technology Development Scenario

Table 3 summarizes the projected technology path for the accelerated scenario. Additional information detailing the rationale for each 5 year increment can be found in section 4. The accelerated R&D scenario assumes that a good portion of the "advanced turbine" technology is available by 1995, although scale-up to the complete 500 kW advanced turbine design is shown in year 2000. There is higher probability of success for the advanced turbine technology under

Table 3. Projected Technology Path for Accelerated R&D Scenario

Year	Turbine Rated Capacity (kW)	Turbine Diameter (meters)	COE at 13 mph (cents/kWh)	Technology Description
1990	100	18.3	8.1	Composite of 6 commercial turbines.
1995	300	33.0	5.5	Partial "Advanced" design but still 300 kW.
2000	500	40.0	4.7	"Advanced" design plus other improvements
2005	500	40.0	4.3	from basic science research program.
2010	1000	51.7	3.8	Scale up to optimum size.
2015	1000	51.7	3.6	Incremental design improvements to
2020	1000	51.7	3.3	optimum size.
2025	1000	51.7	3.1	
2030	1000	51.7	3.1	

the accelerated scenario because multiple designs will be able to be tested, resulting in less technical risk and more market competition (which should drive product improvement even

further). In addition, technology transfer and design assistance programs discussed below could speed adoption, and improve quality, of the new technology. Further incremental improvements are experienced by 2005, and scale up to an optimum (shown as 1 MW) turbine, utilizing significantly better design tools developed by the basic science element of the program, should occur in the 2010 time frame. Small, incremental improvements should follow after 2010. A detailed breakdown of costs and turbine capacity factors for the base case scenario is given in Table 4.

4.0 RATIONALE FOR TECHNOLOGY IMPROVEMENTS

While the previous section postulated two technology development scenarios, this section describes a general set of technical improvements believed possible, without specifying dates by which they will be realized.

4.1 Current Technology (1990)

The 1990 technology is representative of several of the top-performing commercially available wind turbines, both stall controlled, and variable pitch designs (see reference 5). Because of the large number of commercial turbines installed over the past decade, this information is considered extremely reliable. Furthermore, this data has been reviewed with industry and is widely accepted.

4.2 Mid-Term Projections (1995-2005)

Estimates for the mid-term technology characterizations are based on (1) projections for the U.S Windpower/EPRI/PG&E turbine, described in reference 21, and (2) analysis conducted by SERI of potential advanced design improvements based on technical insights from the current R&D program (the analysis is discussed in this section and is detailed completely in reference 6). The U.S. Windpower/EPRI/PG&E turbine is scaled up from the current 18 meter commercial U.S. Windpower model. Because a prototype of this turbine is currently being field tested, it is clear that market introduction of this technology will precede introduction of the advanced technology described by the SERI analysis. It should be stressed that COE estimates for the former (scaled-up) turbine are based on manufacturer projections and have not been verified by published performance test and hardware cost data.

The general approach used in the SERI analysis to determine the effects of design improvements on existing wind turbine technology can be described by three basic steps. First, a reference system was selected to represent current technology and its performance and costs were tabulated. Because this system was defined seperate from the NES process, it is slightly different from the description of 1990 technology in Renewable Energy Technology Characterizations. Second, two configurations representing possible improvements to the reference design were identified, and the effect of each improvement on performance and cost was estimated. Industry was consulted to corroborate these estimates. Lastly, figures of merit were calculated from the reference and improved design parameters. Table 5 summarizes the reference technology.

Table 4. Cost and Performance Details

ACCELERATED R&D SCENARIO

CAPITAL COSTS ($M)

Major Components	1990	1995	2000	2005	2010	2015	2020	2025	2030
Rotor	14.7	13.0	12.1	11.6	11.0	10.8	10.4	10.0	10.0
Tower	5.5	5.5	53.0	4.8	4.7	4.7	4.6	4.3	4.3
Generator	3.7	3.4	3.3	3.2	3.1	3.1	2.7	2.7	2.7
Electrical	3.7	3.7	3.7	3.5	3.4	3.4	3.3	3.3	3.3
Transmission/ Drive Train	6.3	4.5	4.3	3.9	3.8	3.8	3.3	2.5	2.5
Nacelle	2.8	2.5	2.5	2.4	2.4	2.4	2.3	1.8	1.8
Land	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Balance of System	3.7	3.4	3.2	3.1	2.6	2.6	2.6	2.5	2.5
Total Direct Cost	44.0	39.6	37.8	36.2	34.7	34.5	32.9	30.8	30.8
Installation	7.3	7.0	6.5	5.8	5.4	5.2	5.0	4.8	4.8
Engineering Fee	3.7	3.4	3.2	3.1	2.4	2.3	2.1	1.9	1.9
Total Installed Cost	55.0	50.0	47.5	45.1	42.5	42.0	40.0	37.5	37.5

CAPACITY FACTOR

Regions	Avg. Wind Speed (MPH)	1990	1995	2000	2005	2010	2015	2020	2025	2030
1, 2, 5	13	20.0	28.0	30.0	31.0	33.0	33.5	34.0	34.5	35.0
6, 7, 9, 10	14	23.0	32.2	34.5	35.6	45.5	38.6	39.1	39.7	40.3
8	16	30.0	42.0	45.0	46.5	59.3	50.3	51.0	51.8	52.5

Table 5. Reference Design Assumptions

System Rated Capacity	200 kW
Rotor Diameter/Swept Area	25m/491m^2
Total Installed System Cost	\$210,000 (\$430/m^2, \$1050/kW)
Annual Gross Energy Capture	330,000-550,000 kWh (depends on resource) (675 kWh/m^2-1122 kWh/m^2)
Availability	95%
All losses	23%
O&M Costs	\$0.010/kWh
Replacement Costs (8th year)	\$30,000
Replacement Costs (20th year)	\$30,000
All Costs	1989 Constant Dollars

The first turbine configuration SERI identified for mid-term use incorporates a variable speed rotor with pitch control for maximum power control, using power electronics to produce constant frequency line current. It also utilizes advanced control systems to take full advantage of different wind characteristics (i.e, to "smooth" the effects from turbulent wind gusts by absorbing energy, and to adjust rotational speed to longer-duration changes in wind speed), and advanced airfoils for increased power output and reduced loads. The drive train and the rotor hub will incorporate designs optimized for reduced mechanical loading resulting from the other improvements. To take advantage of the fact that wind velocity increases with height above the ground (this occurrence is known as "vertical wind shear") the turbine will be mounted atop a considerably taller tower, which will be optimized for the site.

The second configuration is a stall controlled rotor, using passive aerodynamics to limit maximum power output during high winds. This concept would also take advantage of the other advances in the first concept, including advanced control systems, advanced airfoils, improved rotor and drive train designs, and the taller tower.

The expected impact of improvements in general analytic and design capabilities, as well as specific hardware advances for the two concepts, is shown in Table 6. The improvements are listed as percentage changes relative to the reference design assumptions for system cost, annual energy capture, and annual O&M costs. For instance, for a variable speed turbine design, SERI concept 1, the cost impact from application of the structural codes is a negative 5 percent of the reference (cost is reduced 5 percent of the reference total cost). No change in energy is projected due to the use of this tool. As another example, note that "Control Systems" actually raises system cost by a small amount (the amount is shown as a positive percentage impact), which brings the net cumulative change in cost back up toward the original cost. The cumulative total increase in energy production from all technology improvements to SERI Concept 1 is 46 percent (1.46 x reference energy), while there is no net change in cost from these same improvements. For the stall-regulated turbine design, SERI Concept 2, a total cumulative increase in energy of 39 percent and a decrease in cost of 12 percent, is projected. A discussion of projected key impacts for each design follows. All impacts are assumed to be independent of each other; the presence of one impact should not alter the size of another to a large extent.

Table 6. Performance and Cost Estimates for (1995) SERI Concepts 1 and 2

Technical Advances	% Improvement System Cost	% Improvement Energy Capture	Improvement In Annual O&M (cents/kWh)
Codes			
Structural	5%	--	--
Fatigue	5%	--	--
Micrositing	0%	6%	--
SERI Concept 1 - Variable Speed			
Power Electronics	-10%	10%	.00
Control Systems	-1%	5%	.20
Advanced Airfoils	0%	10%	.10
Drive Train	4%	--	.10
Structurally Tailored Tower	-8%	15%	.01
Rotor Hub	5%	--	.10
Total	0%	46%	.51
SERI Concept 2 - Stall Controlled			
Aero Dynamic Controls	2%	3%	
Control Systems	-1%	5%	.15
Advanced Airfoils (Rotor Design)	2%	10%	.15
Drive Train	2%	--	.10
Structurally Tailored Tower	-8%	15%	.01
Rotor Hub	5%	--	.10
Total	12%	39%	.61

Common To Concept 1 and Concept 2

- Structures Codes - By enabling designers to incorporate better understanding (developed by program R&D) of the loads felt by the rotor, predictive structural analysis codes will allow them to optimize designs, thereby saving cost on materials. Cost savings on the order of 5 percent are predicted by researchers. There are several reasons why the 5 percent estimate is conservative. First, it does not account for any gains in "manufacturability," it is simply an estimate of cost reduction through advances in design capability. Industry has proved that, given advances in the technical base, they are able to bring costs down to a significant degree.

  Secondly, recent research indicates that the estimated percentage is well within reason. One paper [7] from SERI indicates that field tests have confirmed FLAP (Force and Loads Analysis Program) model predictions that teetered, flexible rotor designs show greatly reduced loading compared to rigid hub, stiff rotor designs (see figure 15). From field tests performed in cooperation with industry, the normalized deterministic flapwise bending moments for the first two harmonics of the rotor were found to be generally one-half as much for the flexible design. In addition, the variances of the random blade root bending moments for the rigid design were an order of magnitude larger than for the flexible design. These results agree with FLAP code predictions, showing the importance of designing the rotor blades to produce natural frequencies that are not coincident with rotor passage frequencies. Figure 16 illustrates the correlation between FLAP code predictions and test results for the first two blade harmonics for a rigid hub machine. Loads felt by the turbine tower were also analyzed for the industry turbines. Understanding how to minimize such loads will lead to reductions in material for the tower and other structural components. Again, test results showed that the energy content in the harmonics of the stiff system were higher than for the flexible. Thus, it has been demonstrated that predictive structural design tools will be able to be used to more accurately optimize rotor design and turbine operation to control the harmful loading experienced by the wind energy system.

- Fatigue Codes - Use of fatigue life prediction design codes will reduce installed cost because it will enable manufacturers to design within tighter margins while maintaining fatigue life goals. In addition, a reduction in component replacement costs, resulting from longer lifetime, will be possible. A reduction of approximately 5 percent of cost is estimated for both concepts. (The combined benefit on cost of using predictive structures and fatigue codes is 10 percent.)

  A recent analysis by researchers at Sandia National Laboratories [8] indicates that such reductions in design margin are easily achievable with the use of fatigue analysis/lifetime prediction tools. Using the newly-developed LIFE-2 code, the analysis compares rotor blade lifetime calculations using design-condition inputs to those made with measured-condition estimates from the 34 meter VAWT test program. It found that estimates using the design- conditions consistently underestimated service lives for all operating modes investigated. Because service lifetime was found to be very sensitive to the various lifetime calculation input parameters, a small increase in the confidence of predicting the lifetime calculation input parameters will translate into a significant increase in the confidence of service lifetime prediction, and concurrently, a decrease in

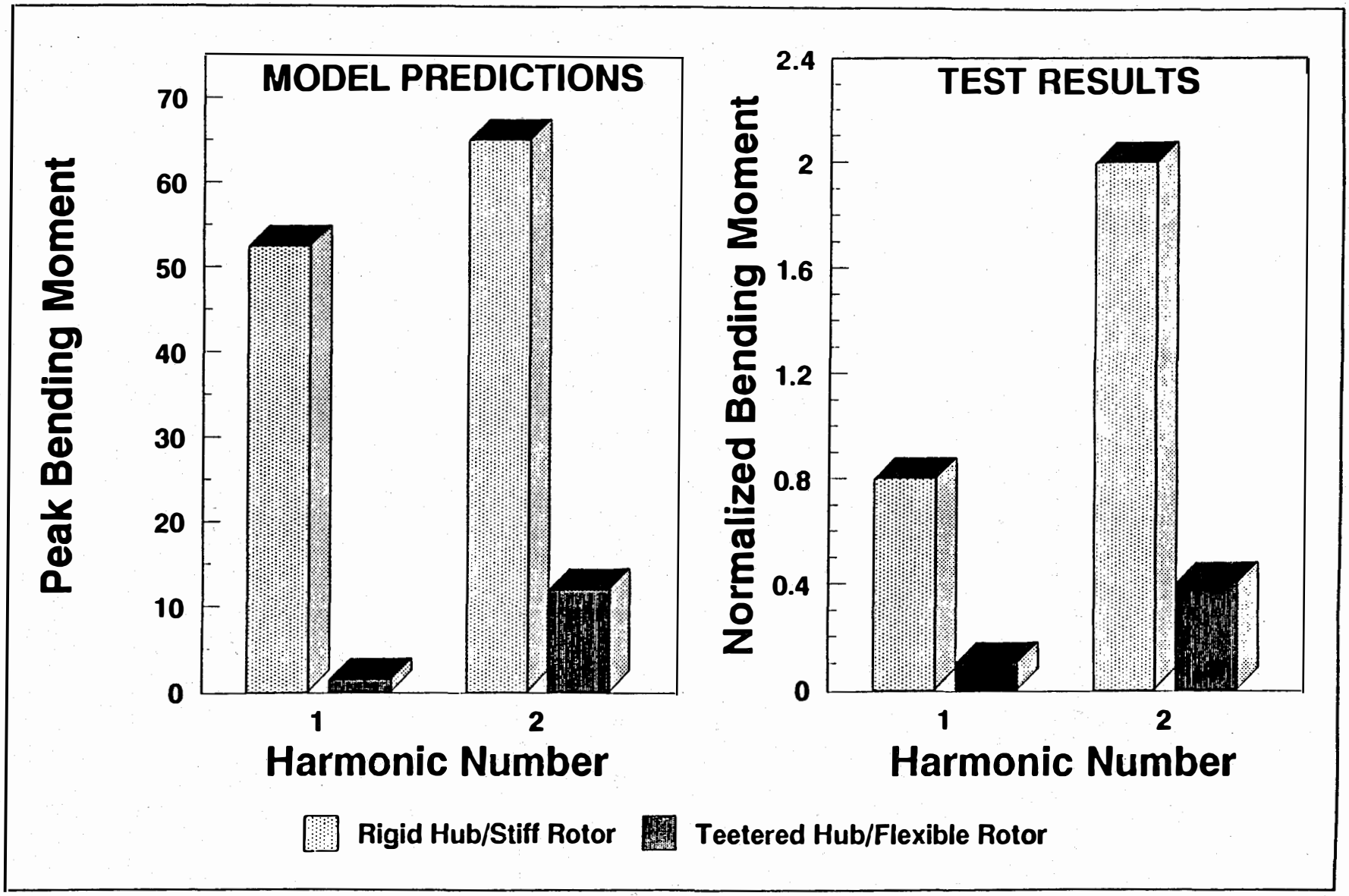


Figure 15. Tests Confirm Predictions That Teetered Flexibile Rotors Show Greatly Reduced Loading

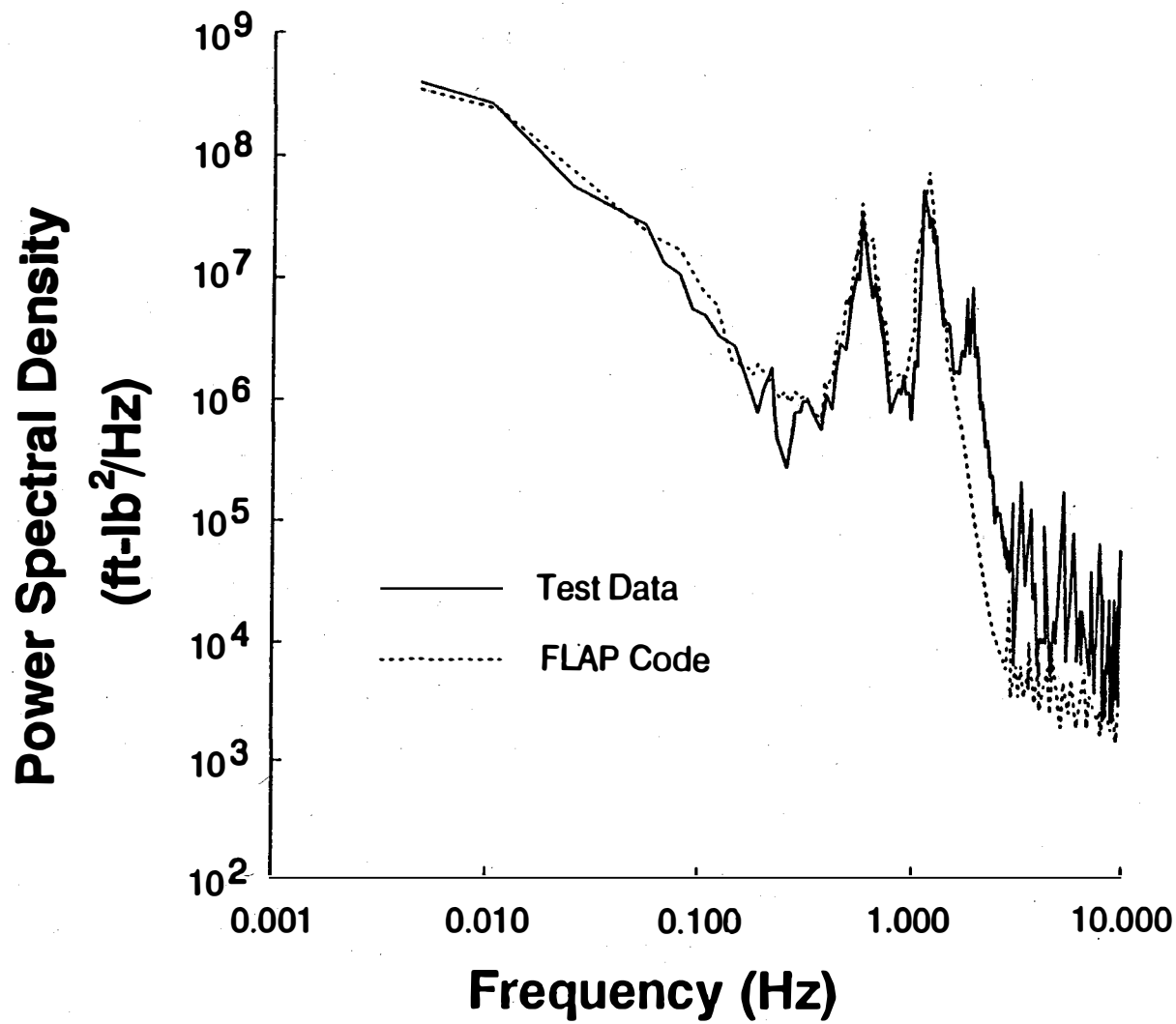


Figure 16. Structural Dynamics Codes Now Predict Turbulence Loads For First Two Blade Harmonics

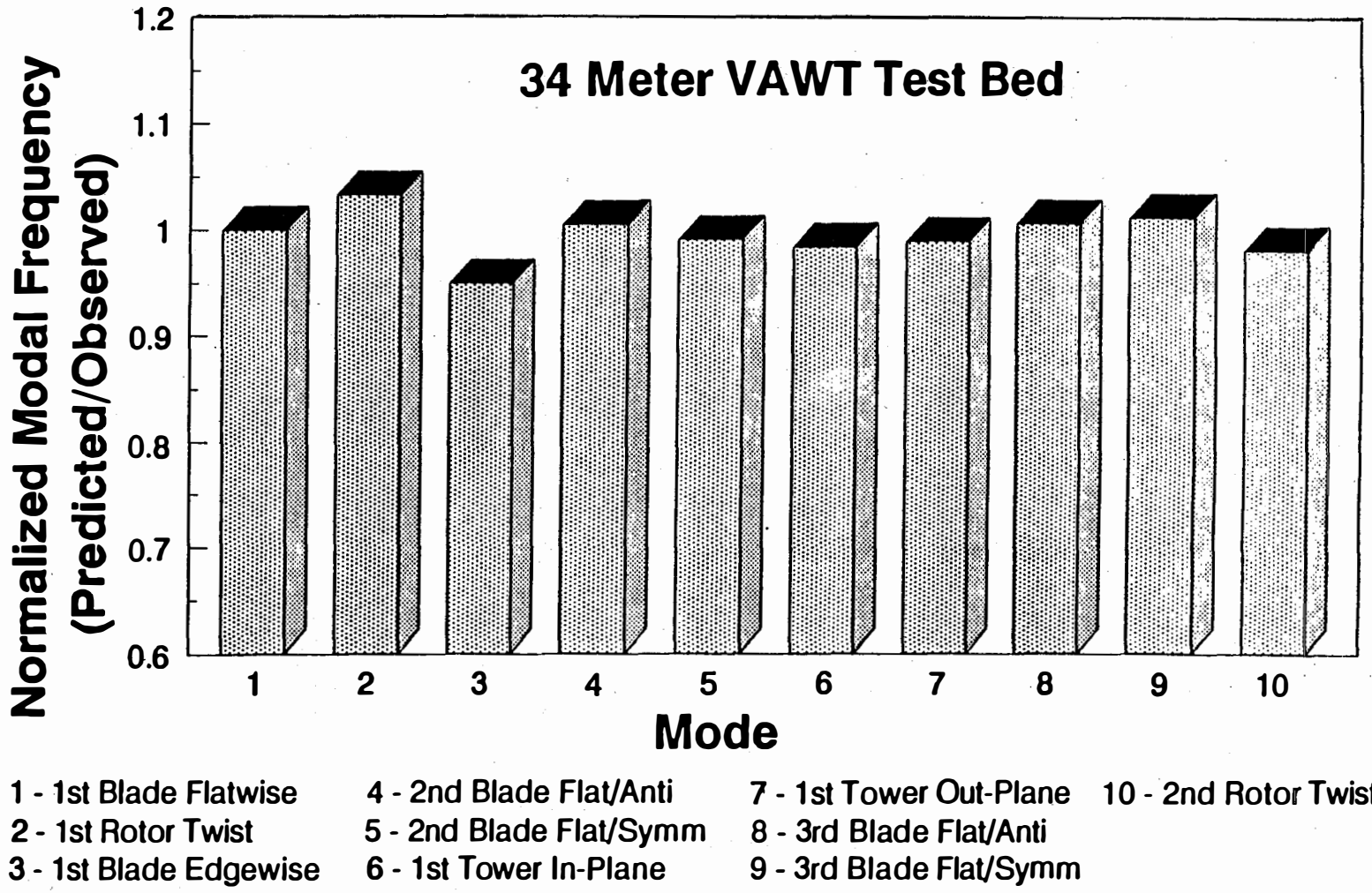
the necessary design margin. Therefore, if designers could have more confidence in the accuracy of the input parameters, they would be able to decrease current design margins.

There are numerous examples of recent progress made by the program in increasing the confidence in predicting the various input parameters. For instance, advances in wind prospecting instrumentation calibration techniques [9] and in theoretical characterization of the incoming wind field [10] have increased the ability to predict both the resource on the larger scale of the array and describe the wind input on the smaller turbine rotor-scale. As shown in figure 17, predictions of mode shapes and frequencies for the 34 meter VAWT test bed have been shown to be within 5 percent of observed values for a wide range of blade modes [11]. Combined, these advances will enable industry to easily meet the 5 percent cost reduction estimate.

- Micrositing - Improved energy capture, on the order of 5 to 10 percent, is possible by locating turbines to avoid losses from wake interactions and to take advantage of terrain-induced effects. Other possible benefits include lower fatigue loads by avoiding local high turbulence zones. Based on recent studies investigating such effects, researchers feel that increasing energy by 5 to 10 percent is well within the range of achievable improvements. Several studies have shown wake energy deficits to be between 20 and 30 percent, and even as high as 40 percent, in the Altamont pass region [12][13]. Figure 18 shows an analysis by Pacific Northwest Laboratories (PNL) of relative energy loss in a wind plant as a function of row number and wind speed. Figure 19 is taken from the Cooperative Test Program and shows macro-scale wake deficits up to 20 percent at a site in the Altamont Pass.

  Using results from array wake measurements taken under the Cooperative Test Program in the mid-late 1980s, researchers at PNL estimate that they were able to predict array deficit uncertainty to within 25 to 30 percent accuracy. The most recent work at PNL involving a comprehensive summary of wake/array loss R&D results should allow estimates to be made with better than 20 percent accuracy. A recent analysis of field data from turbines at the Goodnoe Hills site in Washington concluded that reductions in wind speed of 30 percent and increases in turbulence by a factor of 2 to 3 were present at locations within 500 meters from up-wind clusters of trees [14]. The increased variation of wind speed and gusts created by trees is illustrated by PNL data in figure 20. Another study estimates that of the 50 percent energy shortfall between predicted and actual values for all wind plants in California in 1985, 13 percent was from siting/array losses and 34 percent was from wind resource overestimates [15]. Combined, these studies indicate that a 5 to 10 percent increase in energy capture resulting from a better understanding of micrositing phenomena is quite conservative.

- Advanced Airfoils - Substantial analytical work and field testing of new families of thin airfoils at SERI indicates that predicted energy capture increases of 10 percent have already been exceeded under field test conditions [16]. The improved power output from these blades is shown in figure 21 relative to current technology and the theoretical "Betz" limit. Incorporation of these new airfoils in the next generation of advanced turbines imposes no technical problems. Even greater gains in energy capture have been demonstrated by researchers at Sandia using test results from the 34 meter VAWT test



1 - 1st Blade Flatwise
2 - 1st Rotor Twist
3 - 1st Blade Edgewise
4 - 2nd Blade Flat/Anti
5 - 2nd Blade Flat/Symm
6 - 1st Tower In-Plane
7 - 1st Tower Out-Plane
8 - 3rd Blade Flat/Anti
9 - 3rd Blade Flat/Symm
10 - 2nd Rotor Twist

Figure 17. Accurate Prediction Of Mode Shapes Has Enhanced Structural Prediction Capabilities

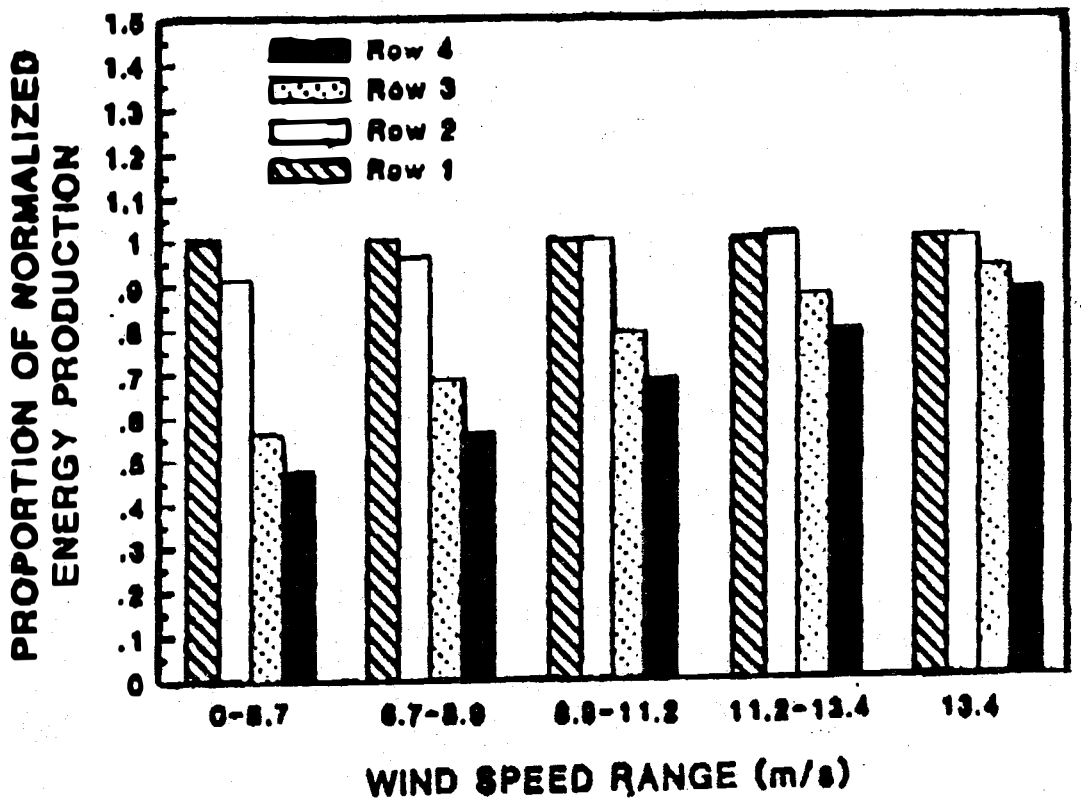


Figure 18. Normalized Mean Row Energy Production As A Function Of Wind Speed

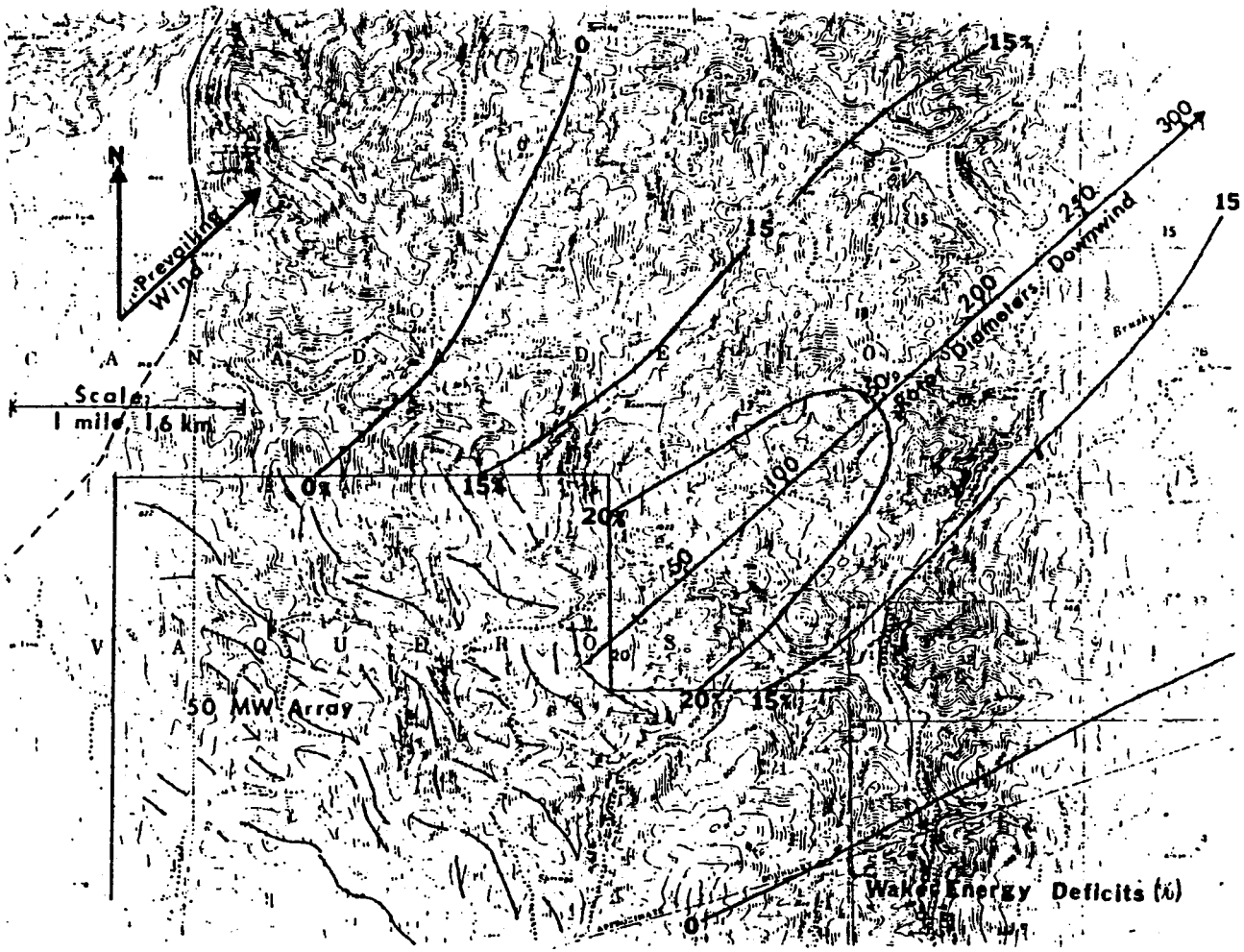


Figure 19. Wake Energy Deficits (%) Downwind Of A 50 MW Array

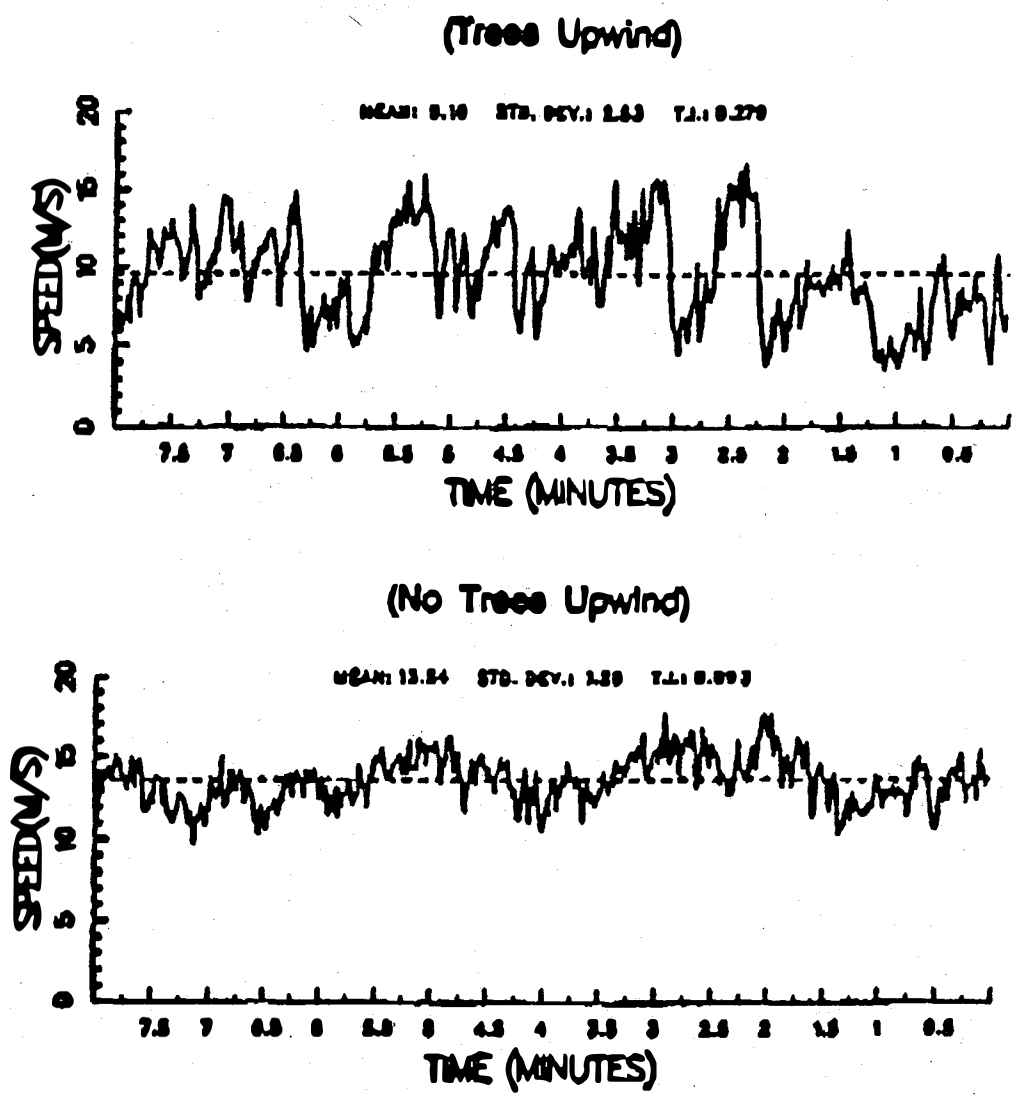


Figure 20. Comparison of Wind Gust Structure With And Without Upwind Trees

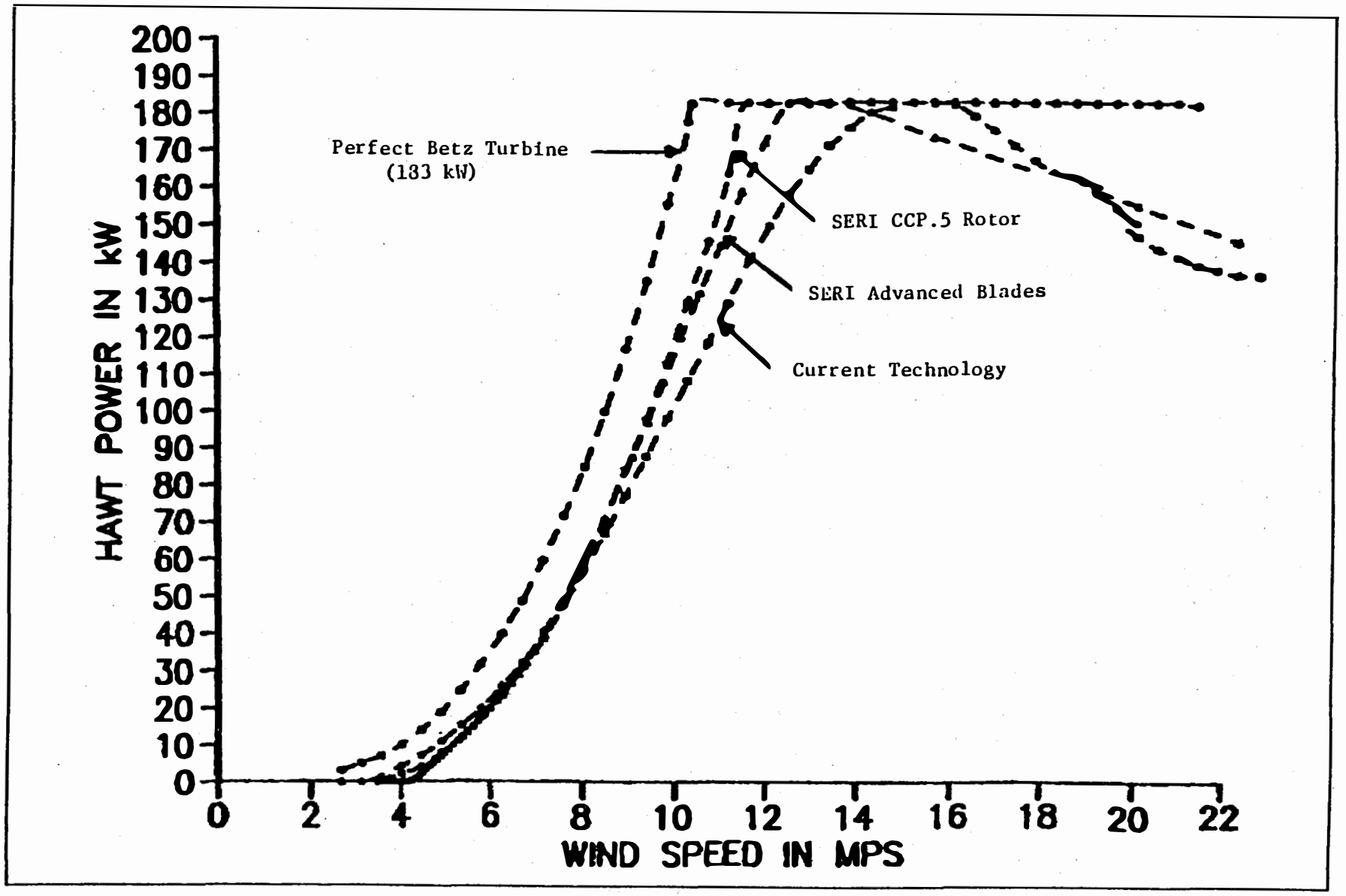


Figure 21. Power Output As A Function Of Wind Speed

bed to confirm projected improvements from airfoils designed specifically for VAWTs [17][18]. These papers confirm earlier theoretical predictions that reductions in wind turbine cost of electricity on the order of 25 percent are possible from the application of natural laminar flow blades [19]. The performance improvement from new families of airfoils is summarized in figure 22.

- Drive Trains - Integrated drive train designs specifically for wind turbines could reduce system costs on the order of 5 percent. The most detailed study of integrated drive train designs was made by the U.S. Windpower/Utility consortium presently developing a new turbine [20]. This paper describes an integrated hub/drivetrain/mainframe which offers a cost advantage compared to the current U.S Windpower turbine model.

- Structurally Tailored Towers - Use of stronger, lightweight materials and new design techniques to tailor towers to sites to take advantage of wind shear and local terrain effects can increase energy production. Obviously, impacts on energy capture and costs will vary depending on the specific design. The analysis in Table 6 assumes an increase in height from 90 to 140 feet yields between 10 and 20 percent more energy (using the "1/7 power law" to scale wind speed) with only a 10 percent cost penalty. (In the figures, note that energy capture increases, but so does cost.)

- Rotor Hub - New rotor hub designs would be optimized to reduce rotor loads by providing increased flexibility. Techniques might include hinged blades, or teetered or gimballed hubs which allow motion in 3 directions. These improved designs would take advantage of new materials and are estimated to reduce system costs approximately 5 percent. Field test data comparing loads between teetered and fixed hubs has verified that reduced loads are possible from such new hub designs [7].

Specific to Concept 1

- Power electronics - Preliminary R&D by the program shows the potential improvement in energy capture from variable speed, constant frequency operation to be on the same order of magnitude as the increase in cost -- near 10 percent [17][20]. The design tradeoff study performed for the current U.S. Windpower/utility turbine development program agrees with this analysis [21]. A key risk associated with the variable speed design is that the rotor speed can coincide with one of the many mechanical resonant vibrational frequencies of the wind turbine, leading to severe material fatigue damage. With proper control, however, these resonances can be avoided (see next bullet).

  Even if the cost-energy tradeoff experienced with the variable speed design comes out basically even, the added benefit of reduction in fatigue loads by avoiding severe operating conditions such as gusty winds without the risk of overpowering the generator system may be enough of a reason to justify its use (see description of a simulated variable speed control system in the following bullet). Again, the industry/utility study agrees with this conclusion, adding that power electronics will impact favorably on power factor control and will help reduce power fluctuations [21]. This paper also states that industry expects power electronic controls (for variable speed systems) to decrease in cost as the technology matures.

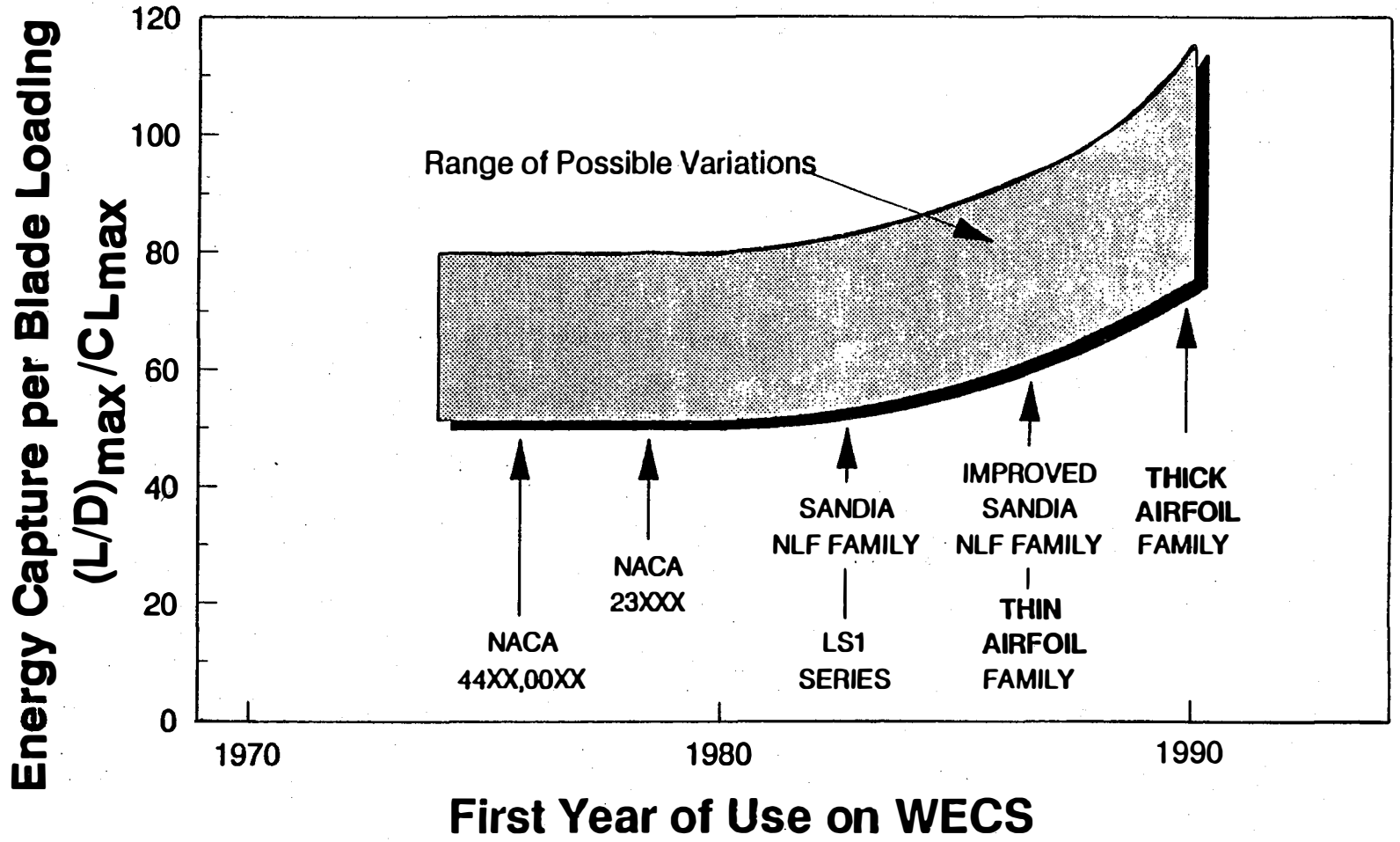


Figure 22. Airfoils For Wind Turbines Generate More Lift With Lower Stresses

- Control Systems - Advanced control systems that not only take advantage of the variable speed capability, but also adapt to local wind resource characteristics, would increase energy capture on the order of 5 percent and minimize damaging fatigue loads. Although the control system cost itself would increase significantly, the increase of the total wind turbine system cost would only be about 1 percent. A recent study by W.A. Vachon and Associates describes a model that simulates variable speed operation, assessing overall impact on life and energy production for numerous control strategies [22]. Use of the variable speed controller described in the paper results in significant reduction in the amount of time the turbine spends operating in a critical speed range (CSR), which consequently reduces the cumulative fatigue experienced by the turbine.

Specific to Concept 2

- Control Systems - The primary control function in a stall controlled design is the capability to adapt operation to local wind resource characteristics, resulting in an approximately 3 percent increase in energy at a total system cost increase of 1 percent.

The combined total effect of these improvements (both concepts 1 and 2) on the levelized COE is to reduce COE for the mid-term to between 5 and 6 cents/kWh for a standard 13 mph site.

4.3 Long-Term Projections (Beyond 2005)

The program-sponsored Conceptual Design Studies for Advanced Turbines, which will begin soon, should provide significant insights into future directions for wind turbine design (specifically, lightweight, horizontal axis designs). It is important to note that projecting the timing of R&D advances requires making assumptions concerning not only the level of R&D effort but also the occurrence of innovations in related fields, such as materials science and power electronics. The extent to which the program follows the conceptual studies with an advanced turbine development program will determine the pace of technology progress in the long term. Despite these uncertainties, preliminary analysis, recently performed by SERI, SNL, and PNL of the potential for longer-term technical advances have identified many areas of promise. Assessment of potential impacts on capital and operating & maintenance cost, reliability/lifetime, and energy capture from both turbine performance and resource utilization, and ability to increase firm power to utilities are summarized in Figure 23. Following is a qualitative summary of each R&D advance area described in that figure.

Atmospheric Fluid Dynamics

- Wind Forecasting - Wind forecasts that are at least as accurate as present temperature forecasts would allow some degree of prediction of wind turbine impact on load demand on various time scales. Such capability would increase the value of wind energy to utilities, especially by reducing the level of spinning reserve requirements.

- Predictive Micrositing Techniques - Siting tools will allow precise design of wind plant layout to minimize wake and terrain effects. While some knowledge in this

R&D Advance	Decreases Capital Cost	Decreases O&M Cost	Increases Lifetime/ Reliability	Increases Energy (Performance)	Increases Energy (Resource)	Increases Firm Power
Atmospheric Fluid Dynamics						
Wind Forecasting						■
Micrositing		■	■		■	
Wind Feed Forward	■	■	■	■		
Wind Characteristics for Design	■	■	■			
Site Tailoring					■	■
Refined Resource Assessment	■				■	■
Advanced Instrumentation	■		■		■	
Aerodynamics						
Stall Controlled Rotor		■	■	■		
Variable Pitch Rotor			■	■		
Variable Speed Rotor		■	■	■		
Passive Controls	■	■	■			
Structures						
Structural Damping	■	■	■			
Transient Rotor control	■	■	■			
Coupled Rotor Control Methods	■	■	■			
Specially Designed Gearboxes	■	■	■	■		
Innovative Towers And Foundations	■	■				
Advanced Materials	■	■	■			
Electrical Systems and Controls						
AI Control and Maintenance		■	■	■		
Low Speed, Small Diameter Generator	■					
Hybrid Systems						■
Soft Utility Interface			■			■

Figure 23. Potential Long-Term R&D Advances In Wind Energy

area will be available for more near-term technology development, more detailed understanding of these interactions and effects will result in decreased fatigue from turbulence and increased energy capture from optimal siting.

- Advance Wind Information For Adaptive Rotor Control - Hub-mounted instruments capable of sensing the approach of extreme shears, vortices or turbulence bubbles would be used to prepare the rotor for damaging transient conditions. By avoiding loads generated by high turbulence and wind gusts, blade and tower weight requirements could be lowered, resulting in cost savings. In addition, lower stress on the turbine components would decrease O&M costs for fatigue-related repairs and replacements. Increased energy capture could also result by being able to orient the rotor for maximum extraction in advance of imminent wind events. Depending on the design of the wind energy system, advanced preparation may include feathering the blades, changing yaw orientation, or applying/releasing yaw dampers or brakes.

- Wind Characteristics for Prescriptive Design - Turbulence and other wind events must be correlated with the types of loads they create over the entire range of operation. Although turbulence will be an important consideration in the design of more near-term advanced turbine technology, complete characterization of turbulence in terms of what is critical to the designer will require longer-term research. Specifically, this research will provide the capability to manipulate the effects of turbulence on the rotor blade boundary layer and corresponding rotor loads. Such capabilities will result in lower costs through lower design margins (weight reductions) and advances in manufacturing process efficiency.

- Site Tailoring - Wind turbines can be tailored to fit or modify specific site characteristics to adapt the site for more efficient and less stressful operating conditions. For example a tilted upwind row of rotors can lower or raise a wind shear layer and "wind wall" layouts can be used to extract the most possible energy from a high speed laminar flow layer or jet. In addition to larger energy capture and lower fatigue loads, tailoring turbines to specific sites will increase firm power to utilities by maximizing energy output during the peak power output periods.

- Refined Resource Assessment - Remote sensing, digital terrain maps, and satellite photographs of vegetation and wind-modified geological features can be used to refine present resource maps, identifying hot-spots that have been missed. Exploiting areas of maximum wind resource is the easiest way to reduce the cost of electricity from wind energy by simultaneously increasing energy output and reducing required land area, which in turn reduces costs. Refined assessment will also increase benefits to utilities by identifying areas that maximize energy output during the peak power output periods, possibly adding firm capacity to the system.

- Advanced Siting Instrumentation - Acoustic sounders can now measure winds from the 10-meter level. Together with profilers and Sodar, such new instruments could enhance rapid wind prospecting by eliminating the need for

expensive meteorological towers, allowing a large number of detailed wind profile characterizations over large land areas. This would result in an increased identifiable energy resource. Increased lifetime and reliability would also result by allowing developers to avoid areas with highly damaging wind characteristics.

Aerodynamics

- Stall Controlled Rotor - A stall controlled rotor is one that relies solely on its aerodynamic characteristics to limit the amount of power that it extracts from the wind during times of very high wind speed. Constant tangent force (C_T) airfoils offer improved stall characteristics and, together with boundary layer control and optimized blade geometry, could dramatically decrease rotor and drive train loads and reduce potential dynamic and utility interface problems associated with very large stall controlled rotors. Energy output could be increased by tailoring power output maximums to high-duration wind speeds, manipulating C_T across the blade span to maintain an energized boundary layer, and decreasing stall hysteresis effects.

- Variable Pitch Rotor - A variable pitch rotor incorporates blades that can rotate around their own axis ("pitch") in order to aid in starting, stopping, and regulating power output by changing the angle at which blades cut through the air. Desirable airfoil characteristics for variable pitch rotors are presently unknown. Parametric studies would define behavioral attributes, which would then be tested in wind tunnels and the free atmosphere. Both lifetime and reliability would be increased by reducing blade loads, reducing dynamic stall events and eliminating high wind gust loads and overspeed events. Increased energy would result by reducing rotor response to high energy gusts and greater efficiency at low wind speeds than for a stall controlled rotor.

- Variable Speed Rotor - Variable speed rotor systems use power electronic control systems to vary the rotational speed of the rotor, depending on the incoming wind speed. This mode of operation is more efficient, resulting in increased energy capture. Also, using the change in rotor speed to absorb gust-induced loads, the rest of the turbine components may be made lighter and smaller, saving cost. The characteristics desired for variable speed rotors are also unknown. The control of such rotors is critical to their success. Passively controlled blades with multiple airfoil designs on a single blade are a possible approach. Increases in energy output could be realized by allowing maintenance of an optimum tip-speed ratio over large ranges of wind speed. Additionally, increased lifetime and reliability and decreased O&M costs would result from reducing the number of control events (braking, rotor pitching) that cause high loads on control devices and from the "smoothing" operating characteristics of large variable speed rotors, which are able to store energy from gusts and supply energy during short-lived periods of rotor-scale wind deficits.

- Passive Controls - Many passively activated aerodynamic brakes have been designed, but none has achieved the total reliability required to provide fail-safe turbine operation. If available, they would decrease O&M cost by eliminating

the need to adjust or repair electro-mechanical actuators.

Structures

- Structural Damping - Advanced rotor and tower structures will be ultra-light and will use passive or active damping for load relief. Capital cost decreases would be realized by a reduction in the required material.

- Transient Rotor Shape Control - Some off-design conditions will be experienced despite "advance wind information" sensors. Instantaneous deformation is one way of controlling the rotor to eliminate responses to high load transient events (such as rapid wind shifts) that can accelerate fatigue damage. Materials research to investigate the use of highly flexible composites and wood laminates will be critical to enabling such design characteristics. Potential for both reduced capital and O&M costs and increased component lifetimes exist.

- Coupled Rotor Control Methods - The coupling of several rotor control methods (e.g., the use of variable speed rotors with delta-3 couplings and variable coning) may have important effects on reducing structural loads and control problems. Because of lower fatigue loads, this would lead to reduced cost by making the turbine lighter and to improved O&M cost and fatigue lifetime.

- Specially Designed Gearboxes - When wind turbines approach large volume production, the cost-effectiveness of special-purpose wind turbine gearboxes (perhaps integrated with generators) will improve. Off-the-shelf gearboxes are a well-known source of reliability problems. While current designs can be tailored and strengthened, redesign will be required to achieve the highest possible degree of manufacturability and reliability.

- Innovative Towers and Foundations - Alternatives to concrete foundations would allow rapid installation in remote areas, thereby reducing costs. Airfoil-section towers without shadows could allow downwind operation, eliminating yaw drive requirements, thus reducing both capital cost and loads created by yaw movements. Advanced tiltable or telescoping towers would reduce maintenance costs and downtime.

- Advanced Materials - Materials structurally tailored for specific applications could include a variety of plastics and wood composites. R&D Goals would include increasing fatigue tolerance, reliability, and manufacturability (reducing necessary design margins, and lowering production costs).

Electrical Systems and Controls

- Artificial Intelligence Control and Maintenance - Microprocessor-controlled internal diagnostics would be able to shut down damaged rotors or adjust their operation to avoid fatigue loads and transients while maximizing energy capture. This would allow fatigue life management to be tailored for each machine and each site, providing a history of cyclical damage events. Such systems would

require improved sensors and strain gages and new methods of remote rotor control.

- Low Speed, Small Diameter Generator - Low speed generators can be used to eliminate gearboxes, but present types have the disadvantage of large size and, in particular, have a high number of poles which increases tower-top bulk. Low speed generators are presently limited in rating to small sizes. Because of the benefits from these generators, wind energy companies are already considering them for stand-alone applications using small-scale turbines. Additional R&D would make these generators scaleable to utility applications.

- Hybrid Systems - Wind turbines may be able to provide a greater percentage of firm power when integrated with hydrogen or battery storage systems (or other storage systems) and other renewables. Hardware cost advantages would accrue by using the power inverters of variable speed systems to integrate battery systems.

- Soft Utility Interface - As the penetration of wind turbines increases to and above 10 per cent, utility integration concerns will increase. Power electronics will be used to improve load following and ramp rates at penetration levels up to 20 per cent. In conjunction with hybrid systems (including storage and backup), new utility dispatching strategies and forecasting methods will increase wind turbine capacity credit and reduce problems associated with resource variability and electric system reliability. Additionally, reliability and lifetime will be increased by avoiding electrical transients and hard shut-downs that cause electrical component wear and fatigue damage.

Integrated Systems Considerations

- Quality assurance methods - Investigation of methods to facilitate advanced manufacturability of components would focus on minimizing manufacturing defects to improve system reliability and lifetime. For example, in the area of advanced materials, materials for injection-molded blades would have to be carefully selected to eliminate voids and weak areas.

Most of the improvements identified for the mid-term are focused on improving energy capture with minimal cost impact. The advances envisioned for the long-term have a much more significant cost impact. Cost decreases will occur from by two primary drivers. First, improved design practices will lead to lighter, more structurally sound and reliable systems. Second, industry will be able to reduce both manufacturing and field deployment costs due to increased scales of production and increased knowledge/experience.

The effect on the levelized cost of electricity from all these incremental improvements is projected to be a reduction to about 40% to 50% of current levels, or to a level of between $0.03 and $0.04 per kWh for a typical Great Plains site.

4.4 Implicit Production Levels

The projected figures-of-merit for wind technology have embedded assumptions concerning production levels. These are relatively unimportant, however, when compared to many other technologies. Unique manufacturing capabilities are not required for most of the components which comprise wind turbines, since for the most part, they are off-the-shelf technology. Blades are probably the only component that must be manufactured specifically for wind turbines, and so their production costs are projected to decrease as volume levels increase. Other components, such as specially designed gearboxes, generators, and electronics can generally be ordered from the factory in block sizes as small as 100 units.

The number of manufacturers is perhaps more dependant on the production demand. A minimum production level of several hundred turbines per year is probably required for most businesses to remain solvent. As the demand for wind energy rises, new manufacturers will find incentive to enter the market.

Near term market projections for wind energy will most likely be limited to about 100 MW per year for the next few years. These installations will fill out the remaining SO-4 contracts offering favorable avoided cost rates. There may also be an influx of Danish and Japanese turbines offering favorable financing and warranties. Deployment of the new U.S. Windpower Model 33-300 will begin around 1995, to meet new markets opening up in the Pacific Northwest as well as other areas with prime resources, such as the Northeast. For example, the Northwest Power Planning Council has included 400 MW of base capacity (1,200 MW of rated wind capacity) in their resource portfolio for planning purposes. This may be developed toward the end of the 1990s. These markets alone are sufficient to maintain the production levels needed to sustain a few wind turbine manufacturers.

If the development of advanced technology were accelerated so that a more competitive product were available in the mid-1990s, the market would certainly be larger. There is a significant amount of land area representing excellent wind sites that would provide wind generated electricity at rates competitive with oil and gas for the near term, if the advanced technology were available for implementation.

4.5 Value of Wind Energy to Utilities

While a reduction in the cost of wind energy is critical to success in the market, estimates of the levelized cost of energy are not equivalent to analyses of the value of wind energy to a utility. Ultimately, power purchase contracts for wind plants will reflect the perceived value to the utility of the source of electricity. Under PURPA guidelines, this value is tied to the avoided cost of generation. The estimate of the worth of wind-generated electricity to a utility can be complex, with evaluations potentially based on a number of factors. This complexity is related in large part to the fact that wind is not an "on-demand" energy source. An effort to assist utilities, utility interest groups, and public power commissions in standardizing their methods of assessing the value of wind energy will help advance and stabilize the market position of wind turbines.

One evaluation factor that is important, but difficult, to assess is the capacity value of wind. Wind energy and other forms of renewable energy without inherent energy storage are commonly characterized as "intermittent" technologies. Government studies involving estimates

of the potential market share of wind energy have assumed that wind energy will displace only the fuel costs and other variable costs associated with generation. Wind energy does have capacity value, however, although none has generally been assigned to it. Its worth, expressed in percentage of rated power of the wind plant, is related to the regular coincidence of wind energy peaks with utility system load peaks. The implications of this are that the value of a wind plant to a utility will depend on the site chosen for the wind plant as well as on the characteristics of the individual utility, with potentially substantial variations in the evaluation from year to year. Still, capacity evaluations for specific years can be made, and a utility may choose to use these as a baseline for establishing contracts. One method of evaluating the capacity value of an intermittent generator is to assess the utility system Loss of Load Probability (LOLP) for a specific year, both with and without the intermittent generator. The LOLP estimates, which characterize utility system reliability, are based on the generating plant sizes, forced outage rates and other plant characteristics, utility load curves, and wind plant generation curves. The Load Carrying Capacity of the generator, which can be considered to be its capacity value, is a function of the ratio of the LOLP without the wind plant to the LOLP including the plant.

The issue of quantifying avoided cost is closely tied to that of estimating capacity value. Total avoided cost includes the avoided cost of new plant construction, as well as fuel and other variable costs. Additionally, there has been growing pressure for the inclusion of the environmental/societal costs of electrical generation. If avoided cost is formulated to include these impacts, then wind energy will be given a substantial advantage over conventional fossil-fired generation. In summary, establishing energy payments based on avoided cost will have to involve determining both the utility's avoided energy and capacity costs, and the specific contribution of a wind plant to avoiding these costs.

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Section 8

TECHNOLOGY EVOLUTION RATIONALE FOR ETHANOL TECHNOLOGY

October 5, 1990

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DRAFT

TECHNOLOGY RATIONALE FOR ETHANOL FROM BIOMASS

I. INTRODUCTION

TECHNOLOGY DESCRIPTION

Biomass is a renewable resource that can be converted into significant quantities of fuel ethanol to lower our nation's dependence on imported oil for transportation energy needs, while reducing urban air pollution, lessening the buildup of atmospheric CO_2, and revitalizing our nation's farm economy. Ethanol can be produced from several biomass feedstocks including sugar, corn starch, and cellulosic biomass, and the technology for using these substrates is in differing stages of maturity. Processes for sugar and corn conversion are practiced commercially, but cellulosic biomass use is still under development. Although fuel ethanol can also be made from ethylene, that technology has been displaced by fermentation ethanol from biomass for fuels applications.

Ethanol from Sugar Cane

About 2.6 billion gallons of fuel ethanol are produced annually in Brazil from sugar cane. However, in the United States, sugar prices are controlled at $360/ton, and ethanol would have to sell at a price of more than $2.30/gallon just to recover the cost of sugar. Because this is well beyond current wholesale gasoline prices, the fermentation of sugar to ethanol is not a competitive technology in this country.

Ethanol from Corn

Essentially, all fuel ethanol, about 850 million gallons, produced in the U.S. today is made from corn by two processes: (1) wet milling and (2) dry milling. Approximately two thirds of all fuel ethanol is produced via the wet milling process and the remainder via the dry milling.

In the wet milling process, all of the components of corn (oil, protein, fiber, solubles, and starch) are first separated from each other. The oil is refined to high-quality corn oil, the protein is dried and sold as high protein animal feed, the fiber and solubles are combined and sold as low protein animal feed, and the starch is processed to make starch products, high fructose corn syrup, or

sweeteners such as dextrose. In turn, the dextrose can be fermented to ethanol. As shown in Figure 1, the following amounts of products are obtained from one bushel of corn (47.32 lb dw): 31.72 lb (67%) of starch, 1.9 lb (4%) oil, 2.6 lb (5.5%) high-protein feed (gluten), and 11.1 lb (23%) low protein feed (corn gluten feed). If all of the starch is used to produce dextrose which is subsequently converted into ethanol, one bushel of corn will yield 2.5 gallons of ethanol. However, it is important to note that not all wet milling plants produce ethanol, and of those that do, ethanol production is seasonal to utilize plant capacity that has been idled by lulls in demand for other starch-based products.

Unlike the wet milling process, the dry milling process is geared primarily for ethanol production. Corn is first milled to open the grain in preparation for the "mashing" or cooking process. Then, the starch in the mash is liquified, saccharified with enzymes, and fermented to ethanol and CO_2 by the action of yeast. The resulting "beer" is next distilled to produce hydrous ethanol, and further processed to produce "pure" or anhydrous ethanol. In addition to ethanol, the dry milling process yields a by-product of dried solid stillage from beer distillation called DDGS (distillers dried grains with solubles), commonly used as a protein animal feed. The three products (ethanol, CO_2. and DDGS) are produced in approximately equal weight per bushel, and using current technology, 2.6 gallons of undenatured fuel-grade ethanol plus 16-17 lb of DDGS are derived from one bushel of corn (see Figure 2).

Ethanol from Cellulosic Biomass

Cellulosic biomass is a complex mixture primarily of carbohydrate polymers from plant cell walls (known as cellulose and hemicellulose) plus lignin and a small amount of other compounds known as extractives. Examples include agricultural and forestry residues, MSW, herbaceous and woody plants, and underused standing forests. The cellulose fraction is composed of glucose sugar molecules bonded together in long chains that are held together in a crystalline structure. The hemicellulose portion of biomass is made of long chains of a number of different sugars and does not have a crystalline structure. For hardwoods, the predominant component of hemicellulose is xylose, a five-carbon sugar that has historically been more difficult to convert into useful products than glucose. Acids or enzymes will catalyze the breakdown of the cellulose and hemicellulose chains into their component sugar molecules that can be fermented into ethanol. On the other hand, lignin is a complex phenolic polymer that cannot be fermented into ethanol.

Over the years, a number of processes have been studied for converting cellulose containing

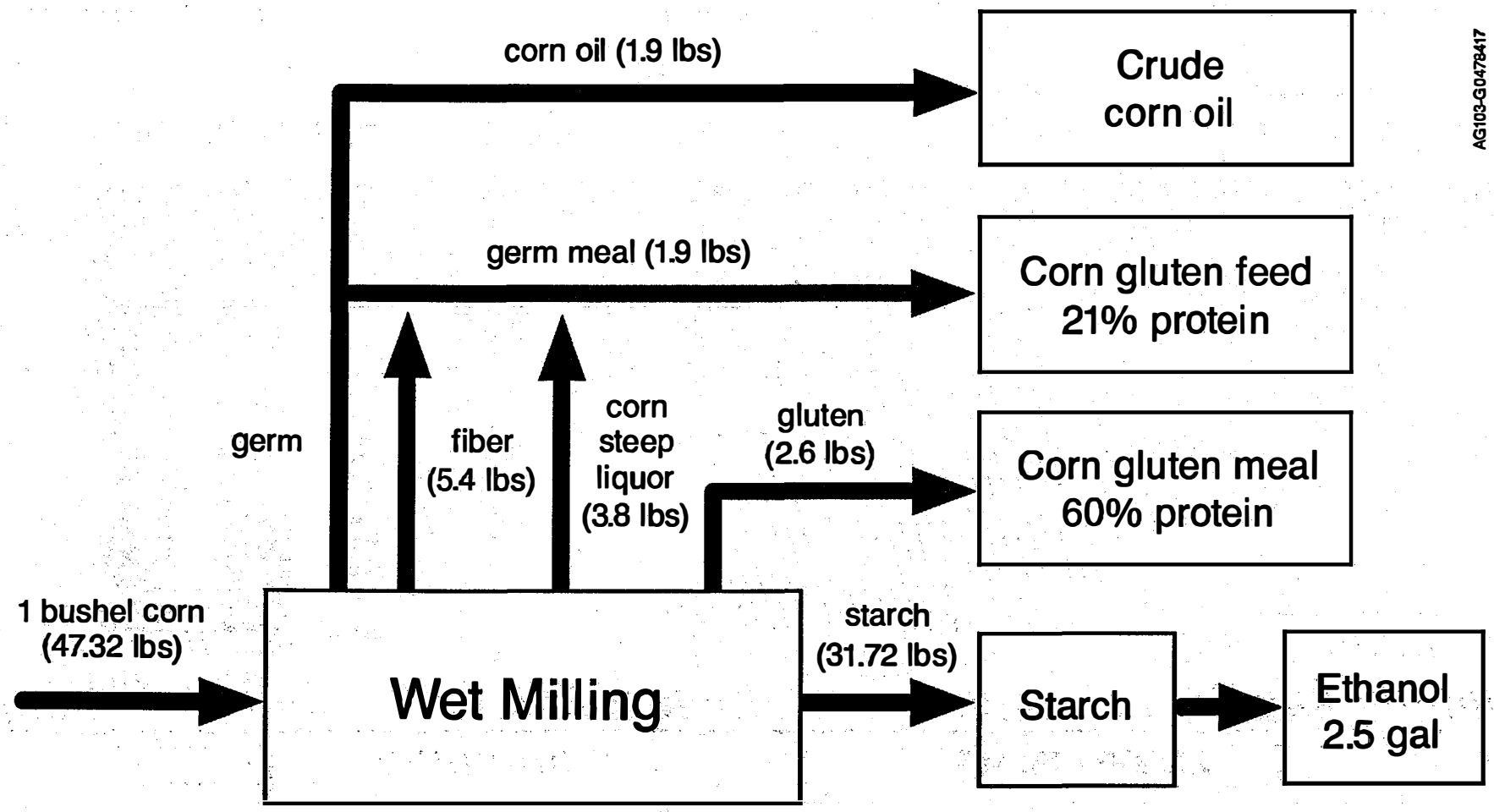


Figure 1. Wet Milling Process

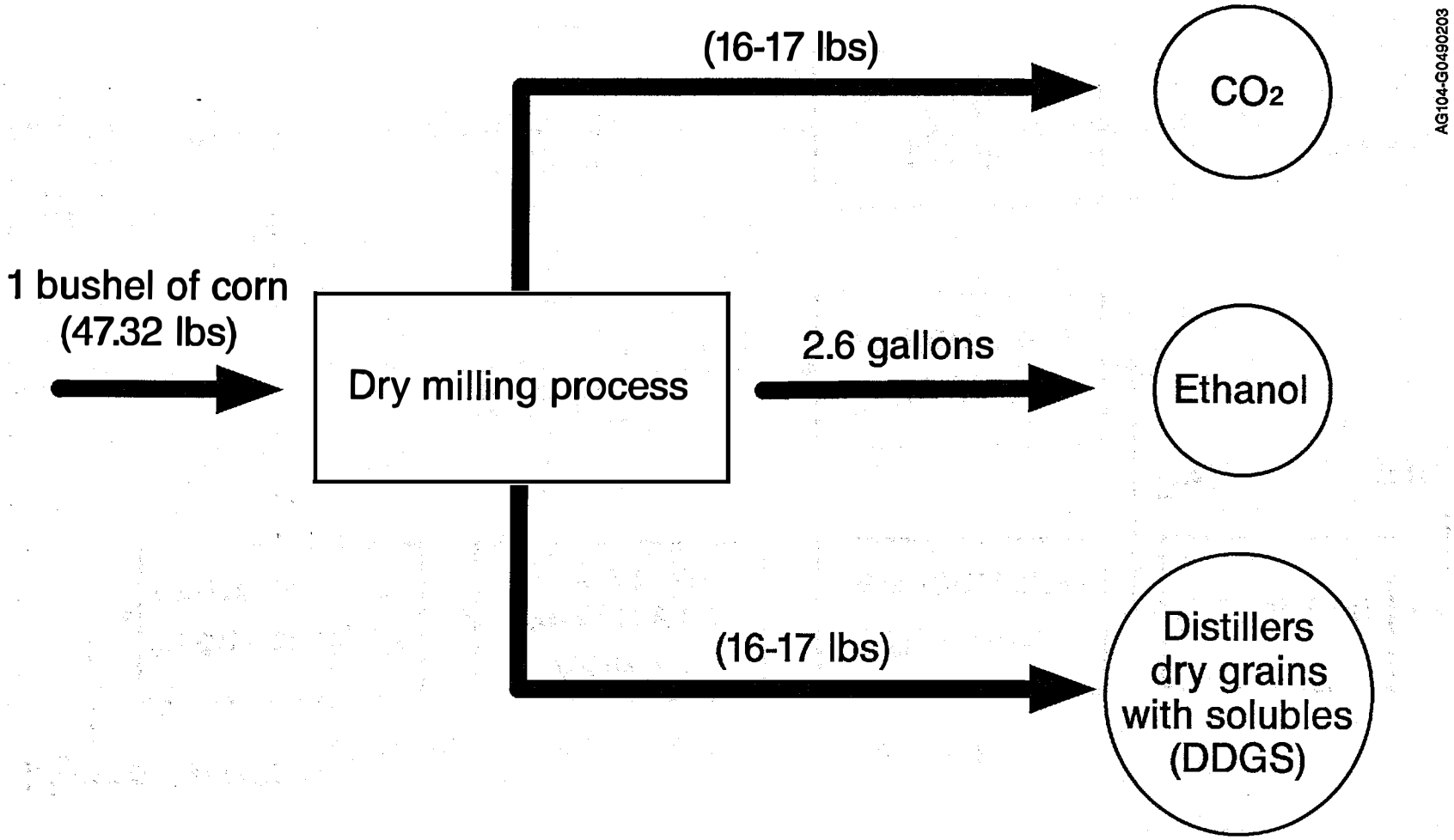


Figure 2. Dry Milling Process

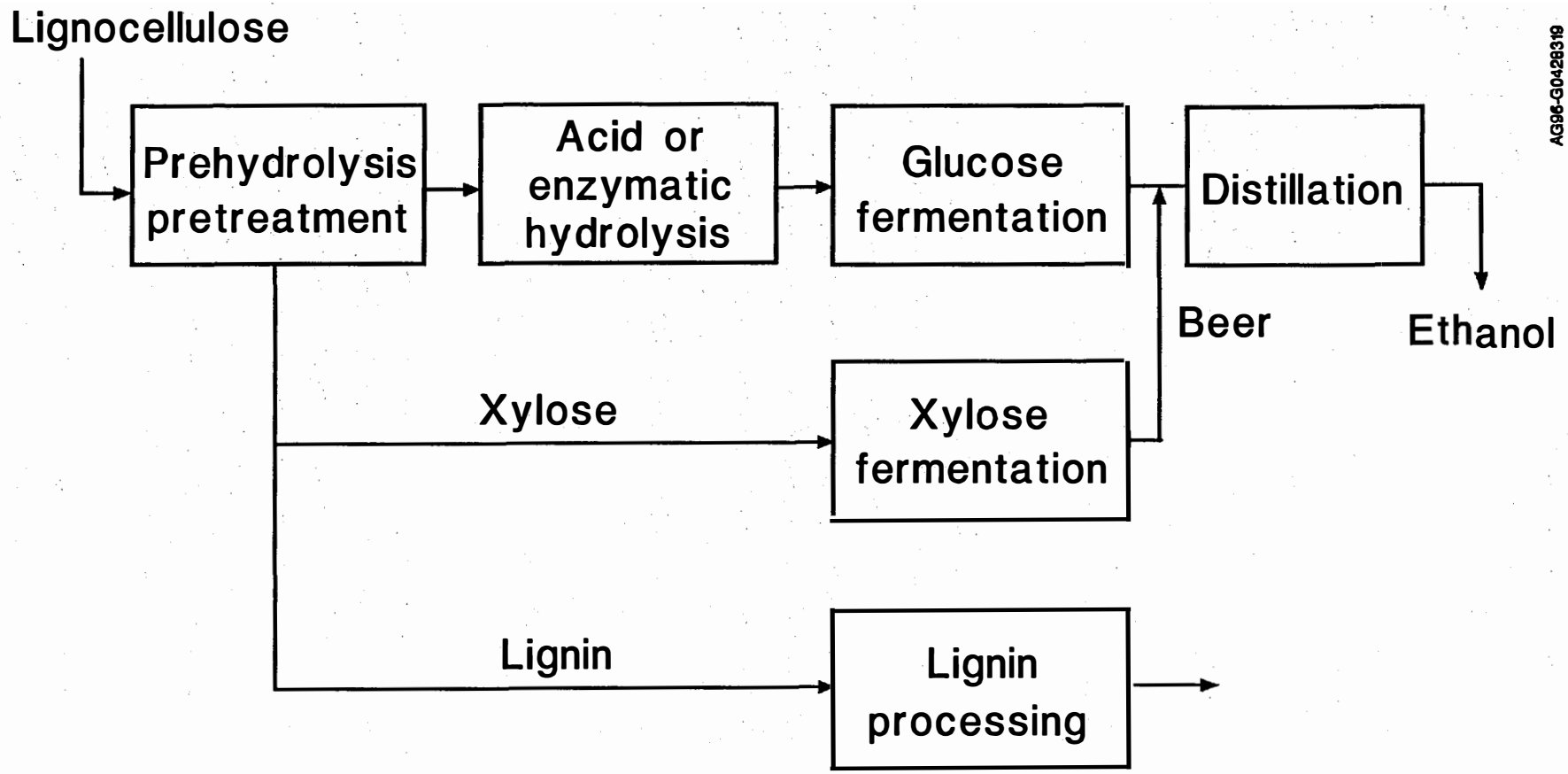


Figure 3. Overall Process Flow Diagram for Acid or Enzymatic Catalyzed Conversion of Cellulosic Biomass to Ethanol

biomass into ethanol. In each of these options, the feedstock is pretreated to reduce its size and open up the structure, as shown in Figure 3. The cellulose fraction is hydrolyzed by acids or enzymes to produce glucose sugar, which is subsequently fermented to ethanol. The soluble xylose sugars derived from hemicellulose during pretreatment are fermented to ethanol as well, while the lignin fraction can be burned as fuel to power the rest of the process or converted into octane boosters.

Acid Catalyzed Processes

Dilute acid catalyzed processes are currently operated in the Soviet Union for conversion of cellulosic biomass into ethanol and single cell protein, and several dilute acid hydrolysis plants were constructed in the United States during war time. However, the economics were too unfavorable to allow continued operation in a free market economy. Thus, acid catalyzed processes provide a near-term technology for production of fuel grade ethanol from cellulosic biomass, but the low yields of 50% to 70% typical of dilute acid systems make it difficult to compete with existing fuel options. Concentrated sulfuric or halogen acid options achieve the high yields required, but because low-cost acids (e.g., sulfuric) must be used in large amounts and more potent halogen acids are relatively expensive, recycle of acid by efficient, low-cost recovery operation is essential to achieve economic operation. Unfortunately, the acids must also be recovered at a substantially lower cost than these inexpensive materials are produced in the first place, a difficult requirement.

Enzyme Catalyzed Processes

Enzyme catalyzed processes achieve high yields under mild conditions with relatively low amounts of catalyst. Enzymes are also biodegradable and environmentally benign. Over the years, several enzymatically catalyzed processes have been studied at the laboratory scale, but only a few investigations have been taken to larger scale equipment. The processes considered include the following:

> Separate Hydrolysis and Fermentation. In the separate hydrolysis and fermentation (SHF) process, the cellulosic biomass is first processed in a pretreatment device to open up the biomass structure and facilitate subsequent processing. A small portion of the pretreated biomass is used in an enzyme production vessel to support growth of a fungus that produces cellulase enzyme, and the cellulase enzyme is added to the bulk of the pretreated substrate in a hydrolysis reactor. At this stage, the enzymes catalyze the breakdown of the cellulose

by the so-called hydrolysis reaction to form glucose sugar, and the stream from the hydrolysis process passes on to a fermenter to which yeast are added to convert the glucose into ethanol. Finally, the ethanol is separated from the rest of the fermentation broth in a purification step.

Simultaneous Saccharification and Fermentation. The sequence of steps for the simultaneous saccharification and fermentation (SSF) process is virtually the same as for separate hydrolysis and fermentation except that hydrolysis and fermentation are combined in one vessel. The presence of yeast along with the enzymes minimizes accumulation of sugar in the vessel, and because the sugar produced during breakdown of the cellulose slows down the action of the cellulase enzymes, higher rates and yields are possible for SSF than SHF. Additional benefits are that half as much expensive fermentation equipment is needed, while the presence of ethanol makes the fermentation mixture less suitable to support invasion by unwanted microorganisms.

Direct Microbial Conversion. The direct microbial conversion (DMC) process combines the enzyme production, cellulose hydrolysis, and sugar fermentation steps in one vessel. In the most tested configuration, two bacteria are employed that produce cellulase enzymes and ferment the sugars formed by breakdown of cellulose and hemicellulose into ethanol. Unfortunately, the bacteria also produce a number of products in addition to ethanol, and yields are lower than for the SHF or SSF processes.

TECHNOLOGY APPLICATIONS

The major market for ethanol is in the transportation sector where ethanol can be directly blended with gasoline to form gasohol, reacted with isobutylene to form the oxygenated fuel additive ethyl tert-butyl ether (ETBE), or burned directly as a neat automotive fuel. Gasohol has a higher octane than the blending gasoline, and the EPA has stated that gasohol is effective in reducing carbon monoxide (CO) levels in cities. ETBE boosts the octane of the gasoline to which it is added; lowers the fuel vapor pressure, thereby cutting smog-producing emissions; and because it is oxygenated, reduces CO emissions. Pure ethanol provides high performance and high combustion efficiency and has properties which will significantly reduce urban smog. Moreover, it is relatively environmentally safe, as witnessed by the fact that it is consumed by humans in alcoholic beverages.

At this time, essentially all fuel ethanol in the U.S. is produced from corn. About 340 million

bushels of corn are used each year to produce about 850 million gallons of anhydrous ethanol. This is enough ethanol to blend at 10% with approximately 8% of the 112 billion gallon U.S. gasoline market. ETBE is under development by several companies, including major oil companies, and with the recent U.S. government ruling to give ethanol used to produce ETBE the same gasoline excise tax exempt status as ethanol used to produce gasohol, ETBE could enter the market place in the near future. Furthermore, states such as California now promote the development of alternative fuel vehicles which can run on alcohol fuels, gasoline, or any mixture of the two, and the availability of such vehicles will provide an opportunity for the use of neat ethanol.

Currently ethanol from corn sells for about $1.20/gallon, and the price of corn at about $100/ton is too high to produce ethanol at prices competitive with gasoline at today's prices, even with substantial co-product credits. Thus, relaxation of highway taxes are employed to encourage ethanol use in the United States. Furthermore, it has been estimated that only about an additional 5 billion gallons of ethanol could be produced from corn in the United States before the co-product markets and overall economics would be affected. Although corn will prove a valuable source of ethanol in the short run, the limited co-product market and restricted availability of acceptable land will hinder substantial growth in ethanol production from corn and growth in the deployment of the three forms of ethanol fuels.

In contrast, cellulosic resources are much more abundant and far cheaper than corn. As a result, cellulosic biomass promises to eventually provide the U.S. with enough ethanol for the entire U.S. automobile fleet at a cost that is competitive, without a tax subsidy, with conventional hydrocarbon transportation fuels. However, cellulosic biomass is naturally resistant to breakdown, and technology improvements are needed to make the process economical. At an accelerated R&D funding level, cellulosic ethanol-based fuels could enter the transportation fuel markets before 2000.

RESOURCE

Appears under Methanol from Biomass.

INDUSTRY STATUS

With escalating oil prices and grain surpluses in the early 1980s, the U.S. corn-based fuel ethanol processing industry grew steadily. Legislation such as the Energy Tax Act of 1978 and the Crude Oil Windfall Profits Tax Act of 1980, also helped to stimulate development of an expanded fuel

ethanol program. From 1980 to 1981, U.S. fuel ethanol production rose from 40 million gallons per year (MGPY) in 1980 to 740 MGPY in 1986 (Fuel Ethanol Cost Effectiveness Study, 1987). With total U.S. gasoline sales in 1986 of nearly 112 billion gallons, U.S. ethanol-blended gasoline sales represented approximately 7% of the country's annual gasoline requirements (Fuel Ethanol Cost Effectiveness Study, 1987). Ethanol production from corn today is about 850 million gallons/year (See Figure 4.)

The present U.S. fuel ethanol industry is comprised of approximately 55 operational facilities in over 20 states (see Table 1). Of these plants, less than half use corn as the feedstock, yet corn-utilization plants produce 85-90% of all fuel ethanol in the U.S. due to their larger production capacities. The remainder is derived from generally smaller ethanol plants using other grains (wheat, milo, barley) or waste materials, including peelings from potato-processing plants, brewery wastes, cheese whey, and canning and food processing wastes (Fuel Ethanol Cost Effectiveness Study, 1987).

Today, the ethanol industry is dominated by several large producers with the largest producer, Archer Daniels Midland (ADM), contributing over 50% of U.S. annual production. Presently, eight U.S. ethanol plants, all having capacities of 40 MGPY or greater, have a combined total capacity of 0.73 billion gallons per year (BGPY), or approximately 77% of all U.S. fuel ethanol production capacity. All but one of the eight largest ethanol producers are situated in the Midwest farm belt. Total operating ethanol capacity is approximately 0.95 BGPY with total production capacity of 1.0 to 1.1 BGPY possible with the inclusion of temporarily-removed capacity. Table 1 provides a listing of fuel ethanol production facilities currently operating in the U.S.

U.S. MARKET ACCEPTANCE AND EXPERIENCE OF FUEL ETHANOL

Today, ethanol has won consumer acceptance with an 8% share of the national market, and in some states, the share is as much as 20%-30%. To illustrate the importance of ethanol, the size of the ethanol blend sales in the U.S. from 1981 to 1987 relative to the fuel market share for several major oil companies is shown in Figure 5. In fact, ethanol blends have a proven value as a high quality transportation fuel by providing consumers with more than 450 billion highway miles. Finally, ethanol blends are approved under the warranties of every automobile manufacturer that markets cars in the U.S.

Up to about 3 billion gallons of ethanol have been used in Brazil, primarily as a neat or pure fuel.

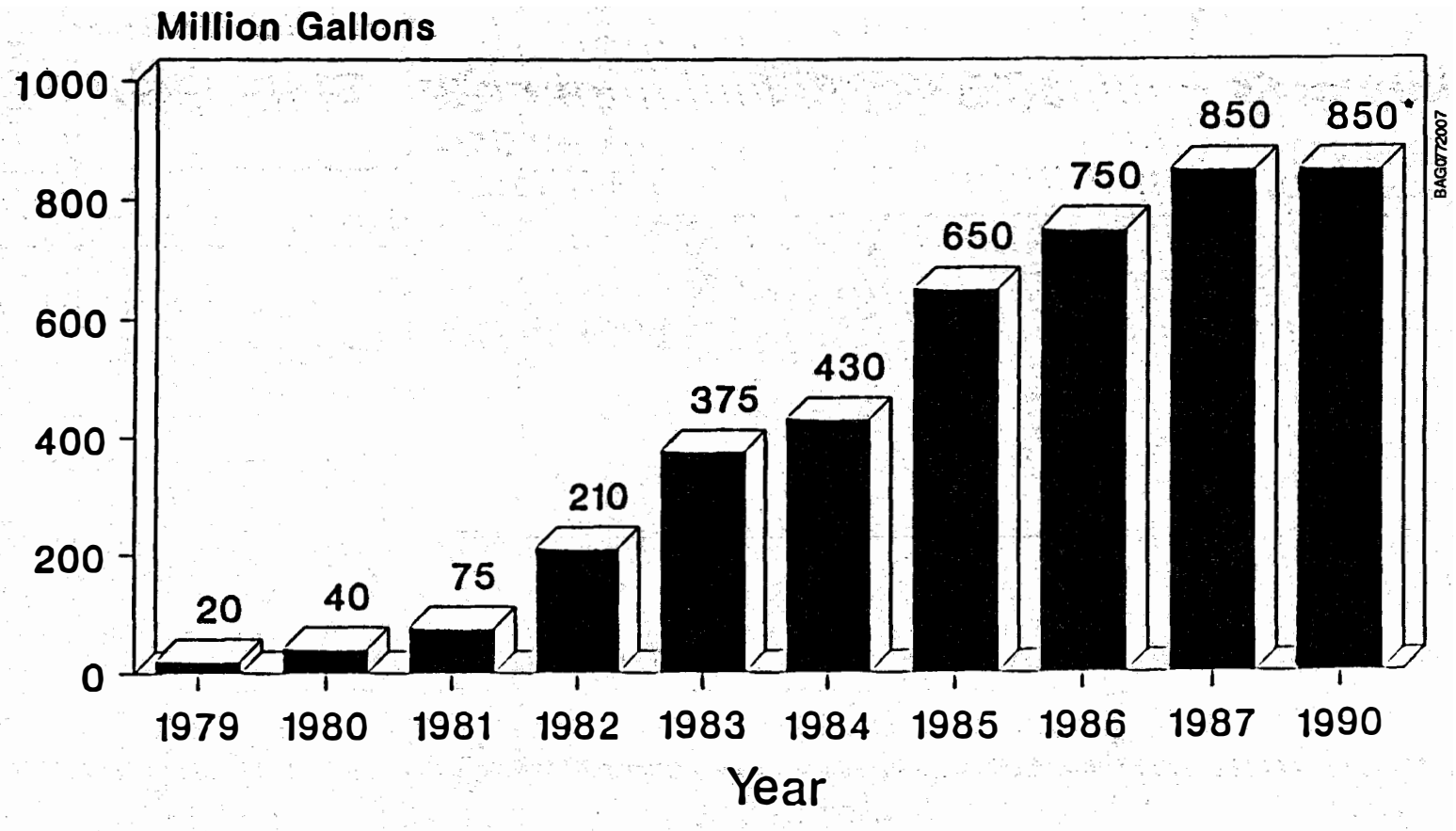


Figure 4. U.S. Fuel Ethanol Production

Table 1. U.S. Fuel Ethanol Facilities Currently Operating
Fuel Ethanol Cost Effectiveness Study 1987

Company	Location	Capacity (000 gal/yr)
Archer Daniels Midland	Decatur, IL	255,000
Archer Daniels Midland	Peoria, IL	95,000
Archer Daniels Midland	Cedar Rapids, IA	80,000
Archer Daniels Midland	Clinton, IA	70,000
Pekin Energy	Pekin, IL	70,000
South Point Ethanol	South Point, OH	60,000
New Energy Company of Indiana	South Bend, IN	60,000
A.E. Staley Manufacturing Company	Loudon, TN	40,000
Shepherd Oil Company	Jennings, LA	25,000
Tennol Energy Company	Jasper, TN	25,000
Kentucky Agricultural Energy Products	Franklin, KY	20,000
Midwest Grain Products	Pekin, IL	12,000
American Diversified Corp. (ADC I)	Hastings, NE	11,000
Grain Processing Corp.	Muscatine, IA	10,000
High Plains Corp.	Colwich, KS	10,000
New Church Energy Assoc.	New Church, VA	8,600
Pinedell, Inc.	Charles City, VA	8,000
Floyd Agri-Energy Coop	Floyd, VA	8,000
Chemical Ethanol Producers	Chesapeake, VA	6,600
American Fuel Trading Co.	Chesapeake, VA	6,000
Virginia Solid Fuels, Inc.	Bealton, VA	6,000
Midwest Grain Products	Atchison, KS	5,500
American Diversified Corp. (ADC II)	Hamburg, IA	5,000
A. Smith Bowman Distillery	Reston, VA	5,000
Grain Power-Tucumcari Ltd.	Tucumcari, NM	4,500
Alchem Ltd.	Grafton, ND	4,500
Butterwood Farms	Wilson, VA	4,000
Virginia Feed & Fuel, Inc.	Madison, VA	3,750
Bio-Regional Energy Associates	Floyd, VA	3,500
Georgia Pacific Corporation	Bellingham, WA	3,000
J.R. Simplot	Caldwell, ID	3,000
Golden Cheese Co.	Corona, CA	2,200
Reeve Agri Energy	Garden City, KS	2,100
G & S Gasohol	Mankato, MN	2,000
Parallel Products, Inc.	Cucamonga, CA	2,000
M.A. Patout & Sons	Jeanerette, LA	2,000
Vidalia 1	Vidalia, LA	2,000
Shreveport Ethanol Inc.	Shreveport, LA	1,600
Alcotech	Ringling, MT	1,500
Grudem Brothers	Jim Falls, WI	1,500
West Texas Ethanol	Clovis, NM	1,200
Parallel Products, Inc.	Winters, CA	1,000
ETOH, Inc.	Wilson, VA	1,000
Ag Power of Colorado	Golden, CO	800
Graf Alcohol	Watertown, MN	800
Vienna Correctional Center	Vienna, IL	750
Southern Ill. Agri Food & Fuel	Brookport, IL	750
Pabst Brewing Co.	Olympia, WA	700
Dairymens' Cooperative	Tulare, CA	700
ESE Alcohol, Inc.	Leoti, KS	500
Plants with Capacities > 40 MGPY		(76.6%) 730,000
Plants with Capacities < 40 MGPY		(23.4%) 223,050
Total U.S. Operational Capacity		953,050

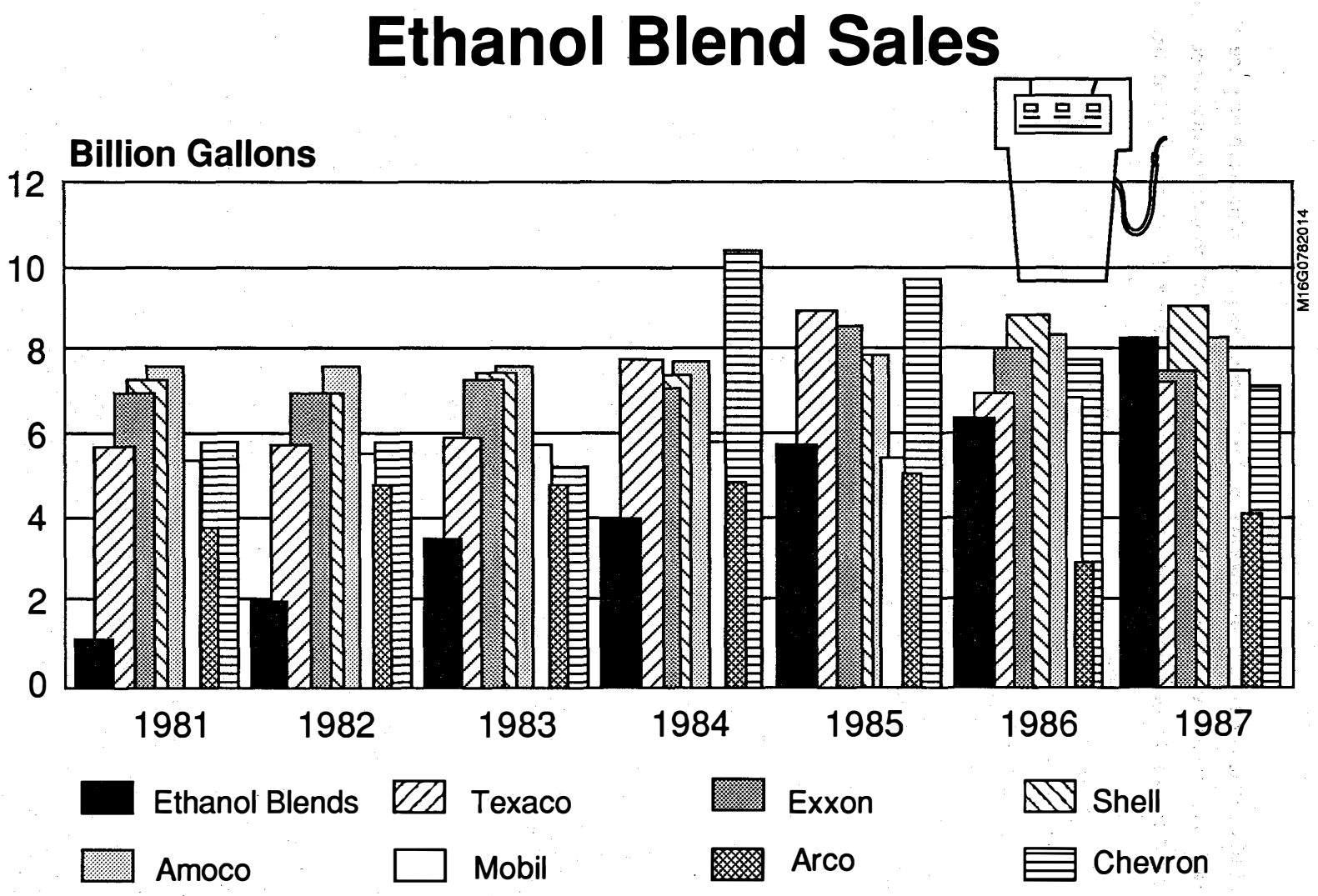


Figure 5. U.S. Motor Fuel Market

At the height of its use, about 90% of new cars in Brazil were designed to operate on pure ethanol. Although Brazil has recently experienced problems with the supply of ethanol because of competing demands for sugar as a food, ethanol has proven to be an excellent fuel when used alone.

II. TECHNICAL STATUS

FIGURES OF MERIT

Technical figures of merit indicate the technical performance status of a process and are useful for communicating research objectives. However, economic figures of merit are more useful in providing a picture of the overall status of a process and are most useful in comparing one process to another. The key economic figure of merit is cost in dollars to produce a gallon of ethanol ($/gallon).

Technical Figures of Merit

- Overall yield (gallons/ton, gallons/bu). The overall yield is the number of gallons of product produced from a given amount of feedstock and is a key factor in achieving acceptable economics.

- Yield (lb/lb). For any reaction step in a process, the yield represents the lb of product produced per lb of feed to the reactor.

- Reaction time (days). For an reaction step in a process, the reaction time is the time required to carry out the reaction.

- Product Concentration (%). The product concentration is the percent by volume of product in the stream that leaves the fermenter that generates the product.

- Mixing power (hp/1,000 gal). This is the power required to mix a reaction vessel by an externally driven agitation device.

Economic Figures of Merit

- Feedstock cost per gallon ($/gallon). This is the cost of the feedstock to produce a gallon of ethanol.

- Net feedstock cost per gallon ($/gallon). This is the cost of feedstock to produce a gallon of ethanol less the revenue from by-products derived from the same amounts of feedstock.

- Total capital investment per annual gallon of ethanol ($/gallon). This is the total capital cost divided by the number of annual gallons of ethanol produced. Total capital investment typically includes all equipment, piping, electrical, instrumentation, structural, civil, buildings, engineering, construction, construction financing, start-up and working capital costs.

- Annual capital charge per annual gallon ethanol ($/gallon). This is a levelized annual charge to cover total capital investment depreciation, taxes, insurance, debt payment, and rate of return on investment to equity holders.

- Energy cost per gallon of ethanol ($/gallon). This is the cost for all fuel (oil, coal, gas, wood, etc.) to produce a gallon of ethanol. Costs of capital required to deliver energy in its final form to the process (boilers, generators, etc.) are not included.

- Operating and maintenance (O&M) cost per gallon ($/gallon). This is the cost for operating expenses to produce a gallon of ethanol. Operating expenses include energy, chemicals and supplies, labor/supervision, maintenance, and plant overhead.

- Selling price ($/gallon). This is the selling price for a gallon of ethanol that must be realized to cover feedstock cost, O&M, energy costs, and annual capital charges.

TECHNOLOGY TREND

Corn to Ethanol

There have some improvements in fermentation technology that have increased fuel ethanol yields above 2.6 gallons/bushel of corn, but the maximum yield with current corn varieties is about 2.7 gallons/bushel (Fuel Ethanol Cost-Effectiveness Study, 1987).

Cellulose to Ethanol

During the last ten years, SERI has examined the potential of various technologies for conversion of cellulosic biomass to ethanol, including dilute and concentrated acid hydrolysis and enzymatic hydrolysis. These analyses have conducted in house and through several engineering subcontractors. As a result of these analyses, SERI believes that the SSF enzymatic process has the greatest potential for the production of low cost ethanol from cellulosic biomass.

Progress on the enzymatically catalyzed processes for converting cellulosic biomass to fuel ethanol has been substantial over the last ten years, with projected selling prices dropping from about $3.60/gallon in 1980 to only $1.35/gallon in 1988. This reduction in selling price is due to improvements in cellulase enzymes to achieve high yields with lower loadings, proper selection of fermentative microbes, higher yields resulting from the SSF process, and development of technology for fermentation of xylose to ethanol. As shown in Figure 6, improvement of the cellulase enzyme was largely responsible in reducing the cost from $3.60/gallon in 1980 to $2.25/gallon in 1985, while incorporation of the SSF process in 1986 dropped the cost to $1.65/gallon. Finally, development of technology based on genetic engineering for conversion of xylose to ethanol is responsible for further reducing the cost to $1.35/gallon in 1988. Bench scale experimental projects are now underway to improve xylan to xylose yields, cellulose-to-ethanol yields, SSF mixing power, and SSF rates. Results from these projects are encouraging, and preliminary analysis indicates that the improvements in these performance parameters will result in further significant reductions of the cost of ethanol in the near term.

CURRENT STATUS

Corn to Ethanol

The current costs of producing ethanol from corn vary tremendously from plant to plant and depend upon plant location, size, and process employed. Costs are also greatly affected by whether the ethanol production capacity was obtained by revamping an existing plant, adding onto a plant, or by building a new "grass roots" plant.

The single most significant cost in producing ethanol from corn is the cost of corn itself. Since 1975 the price of corn has varied from a low of about $1.50/bushel in 1986 to a high of $3.50/bushel in 1983, with an average price of about $2.50/bushel. Since 2.5 to 2.6 gallons of ethanol can be

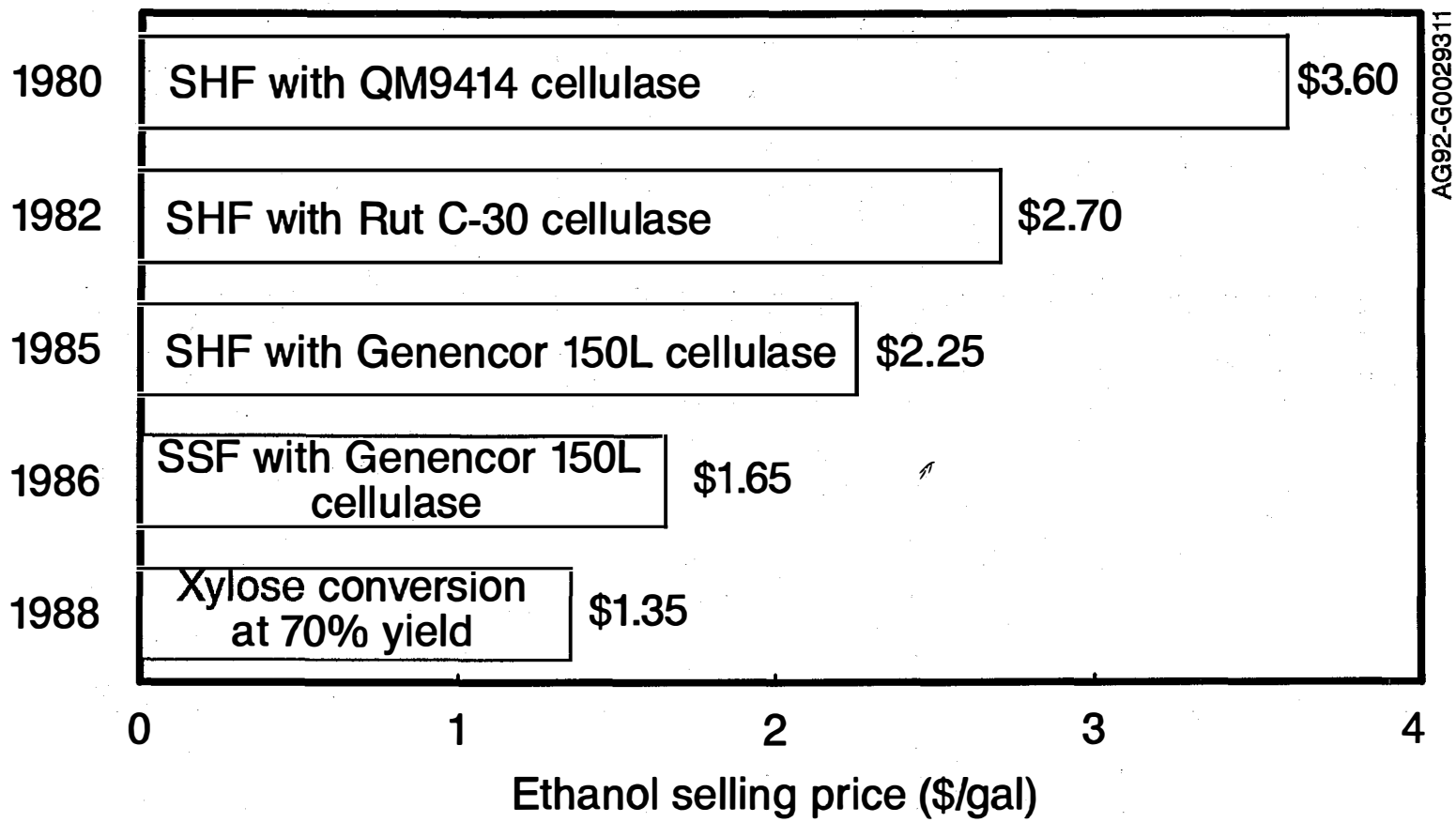


Figure 6. Progress of Alcohol Fuels Research

produced from a bushel of corn, the cost of corn contributes about $1.00 to the cost of producing a gallon of ethanol, which is close to the current selling price of ethanol.

By-products from both the wet and dry milling process have significant value. Typically, the by-products from the wet milling process can be sold for 65% of the cost of corn and the by-products from the dry milling process can be sold for 45% of the cost of corn. As a result, the net feedstock cost for the wet milling process is 35% of the corn cost, and the net feedstock cost for the dry milling process is 55% of the corn cost.

Typical net feedstock cost, O&M cost, and annual capital charges are shown in Table 2. These economic figures of merit show that at current corn and by-product prices, the wholesale costs of producing ethanol ranges from around $1.00/gallon to approaching $2.00/gallon depending upon circumstances. Thus, without blending tax credits, it would not be economical to produce ethanol from corn, since the wholesale market value of ethanol is currently about 67% of the price of gasoline or $0.40/gallon with gasoline selling wholesale at about $0.55/gallon.

Cellulose to Ethanol

Engineering/Economic analysis using bench-scale data indicates that the SSF process, in which xylose is converted to ethanol and lignin is used as boiler fuel, is currently capable of producing fuel ethanol from cellulosic biomass at a cost of $1.35/gallon. The design basis for this analysis, shown in Figure 7, is for a nominal plant capacity of 50 million gallons of ethanol/year; hardwood feedstock cost at $42/dry ton; feedstock composition of 50% cellulose, 25% hemicellulose, and 25% lignin; feedrate at 1,920 tons/year (dw); and on-stream time of 8,000 hours/year. The key technical figures of merit, shown in Figure 8, are: xylan to xylose yield at 70%; cellulose to ethanol yield at 80% theoretical; cellulose conversion time at 7 days; maximum ethanol concentration from the SSF reactor at 4.5%; enzyme loading of 7 IU/gm of cellulose; stirring power at 2 hp/1,000 gallons; and xylose to ethanol yield at 70% with 3% maximum ethanol concentration from the xylose fermenter. Key economi figures of merit besides the cost of ethanol production/gallon are shown in Figure 9 and include: feedstock cost at $0.52/gallon; O&M at $.39/gallon; and annual capital charge of $0.44/gallon.

- Nominal ethanol capacity at 50 million gallons/year
- Feedstock cost at $42/dry ton
- Feedstock composition
  - 50% cellulose
  - 25% hemicellulose
  - 25% lignin
- Feed rate at 1,920 tons (dry weight) per day
- 8,000 hours of operation per year

BAG0772006

Figure 7. Current SSF Design Basis

Table 2. Corn to Ethanol Economic Figures of Merit

Cost ($/annual gallons of ethanol produced)

	A	B	C
Net Feedstock Cost	$0.33	$0.56	$0.38
O&M Cost	0.21	0.46	0.27
Annual Capital Charge	0.47	0.84	0.28
Production Cost	$1.01	$1.86	$0.93

	A	B	C
Process	Wet Milling	Dry Milling	Wet Milling
Project	Revamp	New	Add-on
Size (MMgallons/yr)	120	20	10
Corn Cost ($/bushel)	2.5	2.75	2.40
Total Capital Investment ($/annual gallon produced)	1.70	3.0	1.00

(Keim, C.R., 1989)

Pretreatment

- Xylan to xylose at 70% yield

Cellulose-to-Ethanol

- Yield at 80% theoretical
- Reaction time at 7 days
- Maximum ethanol concentration at 4.5%
- Enzyme load at 7 IU/gm of cellulose
- Stirring power at 2 HP/1,000 gallons

Xylose-to-Ethanol

- Yield at 70%
- Maximum ethanol concentration 3%

Figure 8. Current SSF Technical Figures of Merit

CNM/6127/108

	Xylose to Ethanol, Lignin as Boiler Fuel (¢/gal)
FEEDSTOCK COSTS	
Raw materials - wood	52.16
O&M COSTS	
Raw materials - sulfuric acid	1.65
Raw materials - lime	0.89
Raw materials - chemicals	1.31
Utilities - water	0.74
Utilities - steam	0.00
Electricity	4.77
Labor	5.20
OH & maintenance	24.74
ANNUAL OPERATING COST	91.46
ANNUAL CAPITAL CHARGES	43.58
COST OF ETHANOL	135.04

Figure 9. Current SSF Economic Figures of Merit

CNH/612F108

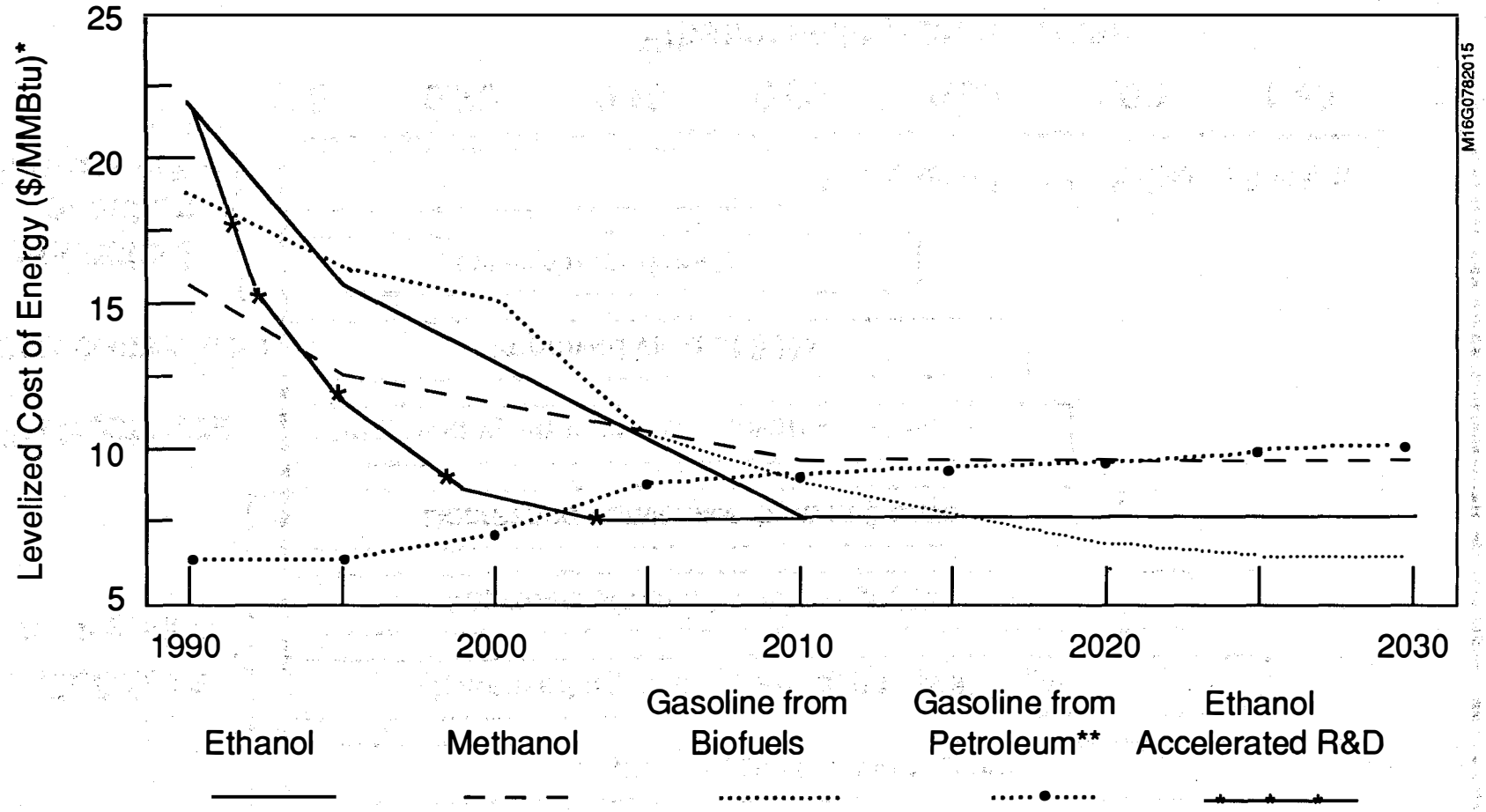
III. COST/PERFORMANCE PROJECTIONS

The improvements in the selling price of ethanol ($/MMBTU of fuel) are plotted against time for the base case and accelerated levels of funding in Figure 10. Also presented is the projected price of gasoline derived from petroleum for comparison, although it should be noted that the price of ethanol is not adjusted for its greater efficiency relative to gasoline. The base case scenario assumes that the annual funding level remains at the FY90 rate over the entire planning period while the accelerated ethanol R&D scenario incorporates a significant increase compared to the base case. Both funding levels are fully described in later sections of this paper.

The projections in technology advances necessary to achieve the progress shown in Figure 10 are based on five studies performed by leading A&E firms under subcontract to determine the potential of ethanol production from lignocellulosic biomass. Three of the studies targeted enzymatic hydrolysis of biomass to produce sugars for fermentation into ethanol, while the remaining two evaluations were focused on acid hydrolysis of cellulosic materials to make sugars that could be fermented into ethanol. During the same period, SERI engineers also performed process engineering studies of enzyme and acid catalyzed processes for ethanol production. Based on these studies and research with both types of processes, enzyme catalyzed breakdown of cellulose into sugars for fermentation into ethanol was selected for emphasis because of the high yields possible, the environmental attributes of enzymatic conversion, and the low cost potential.

At the conclusion of these independent investigations, the material and energy balance data were taken from the studies judged to best represent the state-of-the-art technology and synthesized into a single process for enzyme-based conversion of cellulosic biomass into ethanol. The appropriate operating and equipment cost data were also rolled into the economics of the enzymatic conversion process. The resulting information was then used to develop a computer spreadsheet model that facilitated variation of process performance to assess the impact of possible technology improvements on the selling price of ethanol. A set of economic parameters specifying the interest rate for debt, the return on investment for equity holders, the capital recovery period, the debt/equity ratio, and so on, was employed to calculate the selling price of ethanol given the capital and operating costs. Overall, the spreadsheet model provided a consistent basis to determine the changes in the projected selling price of ethanol with advances in the technology for ethanol production and to identify opportunities to lower the selling price further.

Based on this methodology, the reduction in the selling price of ethanol achieved through past



*Values do not reflect the highter efficiency of alcohol fuels compared to gasoline.
**Based on NES Reference Case, 2/23/90 Draft

Figure 10. Transportation Renewable Technologies.

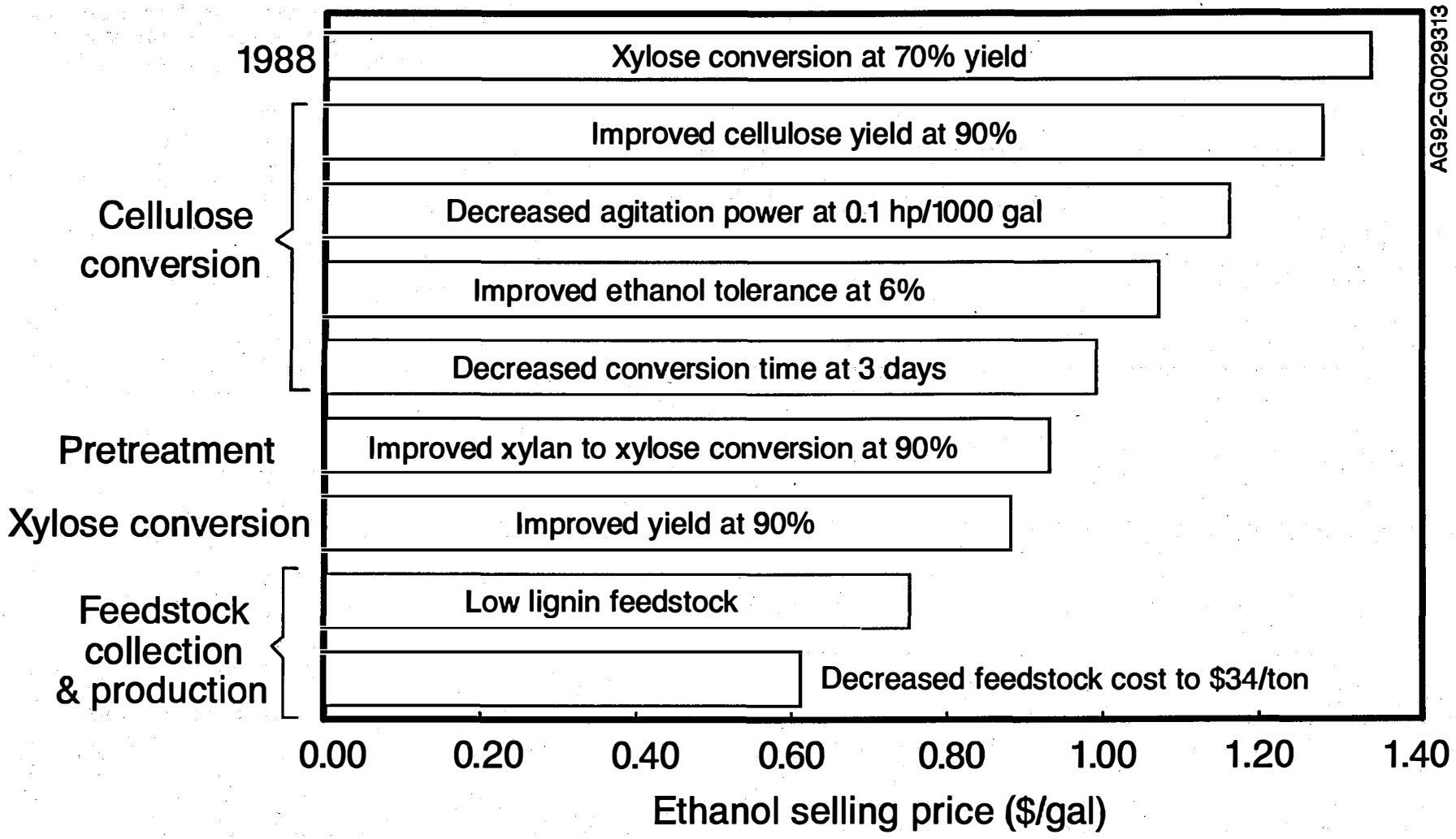


Figure 11. Goals of Alcohol Fuels Research

research was measured, and the impact of potential technology improvements on the selling price of ethanol was assessed. The former investigation showed that the selling price of ethanol from enzymatic conversion methods has dropped from about $3.60/gallon in 1980 to approximately $1.35/gallon now. This drop in selling price has been primarily through improvements in cellulase enzymes and fermentation microorganisms to increase the rates and yields of ethanol production from cellulosic materials, substitution of a combined enzymatic hydrolysis and fermentation process for sequential processing, and genetic engineering of a new organism to ferment xylose to ethanol with 70% yields.

By using the spreadsheet model to determine the impact of potential advancements in technology on the selling price of ethanol, a number of opportunities were identified to improve the technology that would lower the selling price of ethanol to $0.60/gallon, as shown in Figure 11. In addition, other opportunities were defined that could serve as backups for the first set of options. Key target areas include further improvements in glucose and xylose yields from pretreatment, increased ethanol yields to 90% from cellulose and xylose fermentations through continued advances via genetic engineering, decreased stirring and pretreatment power requirements, better productivities through continuous processing and biocatalyst immobilization, low cost production of octane enhancers from lignin, and reduction of fermentation times. Since feedstock costs are a significant fraction of the final product selling price, improvements in feedstock production, collection, and genetics could provide additional cost reductions through economies of scale for larger ethanol plants, decreased feedstock costs, and less non-fermentable feedstock. Many of these goals have been met individually while the evidence that the rest can be achieved is great, and the primary need is to meet them simultaneously. It is also encouraging that enough options exist to lower the selling price of ethanol that not all the technical goals must be achieved to reach the targeted selling price.

Through research accomplished to date, the projected selling price of ethanol has been reduced from about $3.60/gallon in 1980 to approximately $1.35/gallon now, as discussed above. Only 5 or 6 years ago, a typical cellulosic fermentation would require on the order of 12 to 14 days to achieve yields of only about 70% in about a 2% ethanol solution. Now, those same fermentations can be taken to 80 to 90% yields with over a 4% ethanol concentration in just 3 to 5 days. Furthermore, while a few years ago the xylose sugars derived from the large fraction of hemicellulose in biomass could not be effectively converted into ethanol, over 70% of the hemicellulose can now be fermented into ethanol through application of the advances of modern genetic engineering. This change in itself increases the overall ethanol yields by about 35 to 40% while substantially reducing

the cost for waste treatment.

The technical opportunities identified to bring the selling price of ethanol down to $0.60/gallon primarily involve operations that employ biological transformations. In fact, considerable evidence has already been assembled that many of the goals can be realized, and the primary requirement is to achieve them in the context of the overall process. Of course, no one can be certain whether such research goals can be met, but we are quite optimistic since it should be feasible to employ the continuing advances now typical of modern biotechnology to reach the target performance levels. Biotechnology is at the stage of solid state electronics 40 years ago, and an exciting future is probable. Because the techniques and opportunities are so rapidly emerging and changing, the potential for radical changes is immense, and the economics can shift dramatically almost overnight. A key is to utilize the latest developments in biotechnology to devise novel biocatalysts and bioprocesses that will facilitate difficult transformations and dramatically lower ethanol production costs. Furthermore, the advances made through funding this effort will speed up development of the biotechnology industry, improving its competitiveness in World markets for a wide range of products. Thus, just as we have witnessed the tremendous decreases in fermentation times and improvements in ethanol yields though the research performed to date, it should be possible to push yields and rates to target levels while minimizing the cost of biocatalysts and reducing power and energy costs.

These selling price measures and projections are based on data gathered in the laboratory and at the bench. To confirm the projected performance and obtain information that can be used to reliably build commercial plants, integrated experiments must be run at a sufficient scale to gather accurate performance data. However, until significant research advances were realized, it was judged premature to undertake such experimentation. Now, as the technology nears commercial promise, it is timely to begin such evaluations if the funding is adequate. Of course, some modifications in the process will no doubt be needed to address issues that arise as integrated process experiments are run, but the problems that might emerge can no doubt be addressed in a cost effective way.

Several opportunities support the use of ethanol for transportation. First, California is moving rapidly toward mandating use of vehicles designed to run on alternate fuels such as ethanol and methanol. In addition to the neat ethanol market that will likely evolve in major cities to combat the environmental problems associated with gasoline use, ETBE will provide an opportunity to integrate ethanol into the existing fuel market. ETBE should reduce carbon monoxide levels and

boost octane while lowering smog producing emissions.

An important factor supporting ethanol production hinges around the fact that the EPA provides extra weight of up to seven times actual mileage to alternative fueled vehicles in computing fleet mileage for new vehicles. Furthermore, the EPA also will likely not allow further postponements in meeting fleet mileage standards by the automotive companies. Thus, there is significant incentive for the automobile manufacturers to build ethanol fueled vehicles.

Another opportunity for facilitating commercialization of ethanol from biomass is utilization of low value by-product or waste streams from such industries as corn wet milling, whole grain processing, pulp and paper, and agriculture, as well as domestic wastes. These opportunities are particularly appealing since these streams are already collected in large quantities at a central site. Thus, they could provide an early chance to commercialize the technology developed through this Program.

Base Case

There have been some improvements in corn fermentation technology that have increased fuel ethanol yields above 2.6 gallons/bushel of corn, but the maximum yield with current corn varieties is about 2.7 gallons/bushel. Research is being conducted that may lead to future corn varieties with higher starch content, thus raising the possible ethanol yield per bushel of corn. Considerable processing research is also being conducted within the corn ethanol industry and at universities that will increase the efficiencies and ethanol yields of operating and proposed facilities. Much of the research focuses on improved liquefication, saccharification, fermentation, and distillation systems. In the area of fermentation research, continuous fermentation and yeast recycling has been demonstrated in wet-milling operations that increases ethanol output and simplifies fermentation operations. Fermentation processes using immobilized enzymes alone and with yeast have been developed that convert liquefied starch directly into alcohol, with such systems demonstrating high production rates and reduced energy requirements. A promising fermentation process using a bacterium called *Zymomonas mobilis* is also being investigated. This process has de nonstrated several advantages relative to conventional processes, including: 1) reduction in fermentation time; 2) elimination of yeast recycling; 3) increase in alcohol concentration; 4) reduced equipment fouling; 5) elimination of fusel oil and glycerol formation; and 6) increased protein and fat content of by-products. Other research to improve distillation processes is being conducted that will ultimately reduce overall energy requirements for alcohol distillation. Future ethanol plants that employ these developing processes have the potential to reduce the cost of producing fuel ethanol

from corn.

To bring the technology for production of ethanol from cellulosic biomass to commercial readiness, five primary phases of R&D are required: research to improve process steps, integrated process testing, process development unit (PDU) evaluation, engineering development (EDU) experiments, and process engineering evaluations. The first of these, research on process steps, is required to improve biocatalyst and other technology performance to the point identified for an ethanol selling price of $0.60/gallon, and without research targeted toward this end, this economic goal can not be realized. Integrated process testing is then needed to establish the performance of the evolving technology in the context of the overall process and determine interactions between process steps. This element of the ethanol development activity is essential to insure that the technology can perform as targeted when employed in a realistic system. The process development unit (PDU) takes the integrated process testing to a scale sufficient to establish accurate material and energy balance data for the entire operation and is necessary to convince industry of the merits of the overall process and the technology. If data from the PDU scale isn't sufficient to allow industry to reliably build a commercial scale process, then an engineering development unit (EDU) will be required to operate at a semi-commercial scale. Finally, the engineering evaluation element is vital throughout these phases to assess the impact of technology advances and update the economic status to reflect continuing improvements in the technology. This element is also vital in identifying new opportunities for applying the technology.

The projected technical improvements for the base case scenario were established from the assumption that the ethanol R&D funding levels would remain constant from FY90. Thus, the resource base was taken as $2.0 million in real terms over the planning horizon. For such a funding situation, the primary work that can be performed through government support is limited to research on process steps to advance the technology for bioconversion of cellulosic biomass into ethanol, although not all of the needed research can be carried out in this area at the base case level of funding. In addition, limited effort can be undertaken on integrated process testing to determine how the key process steps are interrelated in a real process, and the process engineering evaluations will be continued to insure the limited funds available are focused on the most promising options for technology improvements. However, very little if any effort can be devoted to PDU and EDU experiments, and industry will have to support these elements almost totally.

For the base case funding scenario, it is assumed that industry will support a significant part of the research on process steps as well as virtually all of the PDU and EDU experiments and assessments

of commercial scale technology. However, it is judged unlikely that industry will be willing to invest the amount of funds required until a substantial profit opportunity is evident for ethanol from cellulosic biomass. Such a situation will not likely occur until the projected price of ethanol derived from cellulosic biomass is less than for gasoline and other competing fuels, an event that may not be realized for 15 years or more. At that time, industry may begin to invest in research and engineering to bring the technology to fruition, but at least 5 years will be required to bring a new process on stream. Thus, production of low cost ethanol from cellulosic biomass would probably not begin until after the year 2010.

In summary, if current budget levels are maintained over the planning horizon, the emphasis will have to be on research to improve the performance of the process steps to meet overall economic goals for the most critical areas. Although some integrated scale testing will be performed, operation of PDU and EDU experiments at a scale sufficient to convince industry of the merits of the technology will have to wait until ethanol prices are sufficiently lower than for gasoline from petroleum to merit investment by the private sector. As a result, the initial introduction of technology for production of ethanol from cellulosic biomass at prices competitive with gasoline without subsidy will likely not occur until at least the year 2010.

Accelerated Ethanol R&D

Although an excellent opportunity exists to improve the enzymatic catalyzed conversion of biomass into ethanol to the point that the price of ethanol is competitive with conventional transportation fuels, substantial research must be undertaken on the key process steps of pretreatment, xylose sugar fermentation, enzyme production, and cellulose hydrolysis to accomplish this goal. The goals will benefit from research to develop high yield, high productivity continuous processes that are capable of achieving even lower capital costs. In addition, integrated scale testing followed by operation of a process development unit (PDU) are required to prove the performance of the overall process. A larger semi-commercial scale engineering development unit (EDU) may also be needed to convince industry of the reliability and performance of the process. Supporting research and analysis are essential to address key issues throughout the development of technology and monitor progress. Finally, commercial application of the technology will be accelerated through the utilization of low cost feedstocks.

Six elements are included in the accelerated R&D effort: Research on Process Steps, Integrated Process Testing, Process Development Unit, Engineering Development Unit, Supporting Research

and Analysis, and Integration of Lower Cost Feedstocks. Figure 12 shows key elements of the Program and their relationship for the Ethanol Technology Development Pathway. As research is completed on key technical issues in each process step, testing will be performed of the step when integrated with preceding steps to establish their interaction. Then the PDU and EDU phases will follow. The continuous processing element will follow the same sequence to take technology from the bench to large scale evaluations. The supporting research and analysis will continually interact with the other elements throughout, and the integration of low cost feedstocks will apply emerging technology to an opportunity that will accelerate commercialization.

Research on Process Steps

As shown in Figure 12, the Research element is focused on achieving the technical goals for the individual process steps. Thus, we wish to improve xylose yields from pretreatment to over 90%, achieve better than 90% yields of ethanol from both cellulose and xylose, decrease the overall power for the SSF process, increase ethanol concentrations to 8% in the fermenter, cut fermentation times to 3 days for SSF, lower cellulase enzyme costs, and improve yields of methyl aryl ethers from lignin to 72%. In addition, an activity is included to develop procedures for aseptic operation since it is critical to minimize the loss of feedstock and operating time to contaminated batches. These goals must be achieved before the integrated process evaluations are possible.

Currently, hemicellulose is broken down to form xylose by dilute acids at moderate temperatures during the pretreatment process. This pretreatment step is required to open up the biomass structure and overcome the natural resistance of the biomass to enzymatic attack. The yield of xylose from hemicellulose is now about 80%, and improving the yield to over 90% will lower ethanol prices by $0.12/gallon from $1.35/gallon. This benefit results from enhanced product yields and reduced disposal costs for wastes formed during ethanol production.

The dominant factor in achieving a low ethanol selling price is to maximize the amount of ethanol obtained per unit of feedstock processed. Since cellulose is the major constituent of biomass, it is particularly critical to insure that the highest possible yields are obtained from this fraction. Currently, the expected yield of ethanol from cellulose is about 80%, and an increase in yield to over 90% will lower the price of ethanol by over $0.10/gallon from the current projected price of $1.35/gallon. However, since enzyme production costs are high, it is also critical to achieve this goal while maintaining low enzyme loadings, and yields of xylose from pretreatment must be held high. Once again, the economics of the process benefit by increasing ethanol revenues for the same

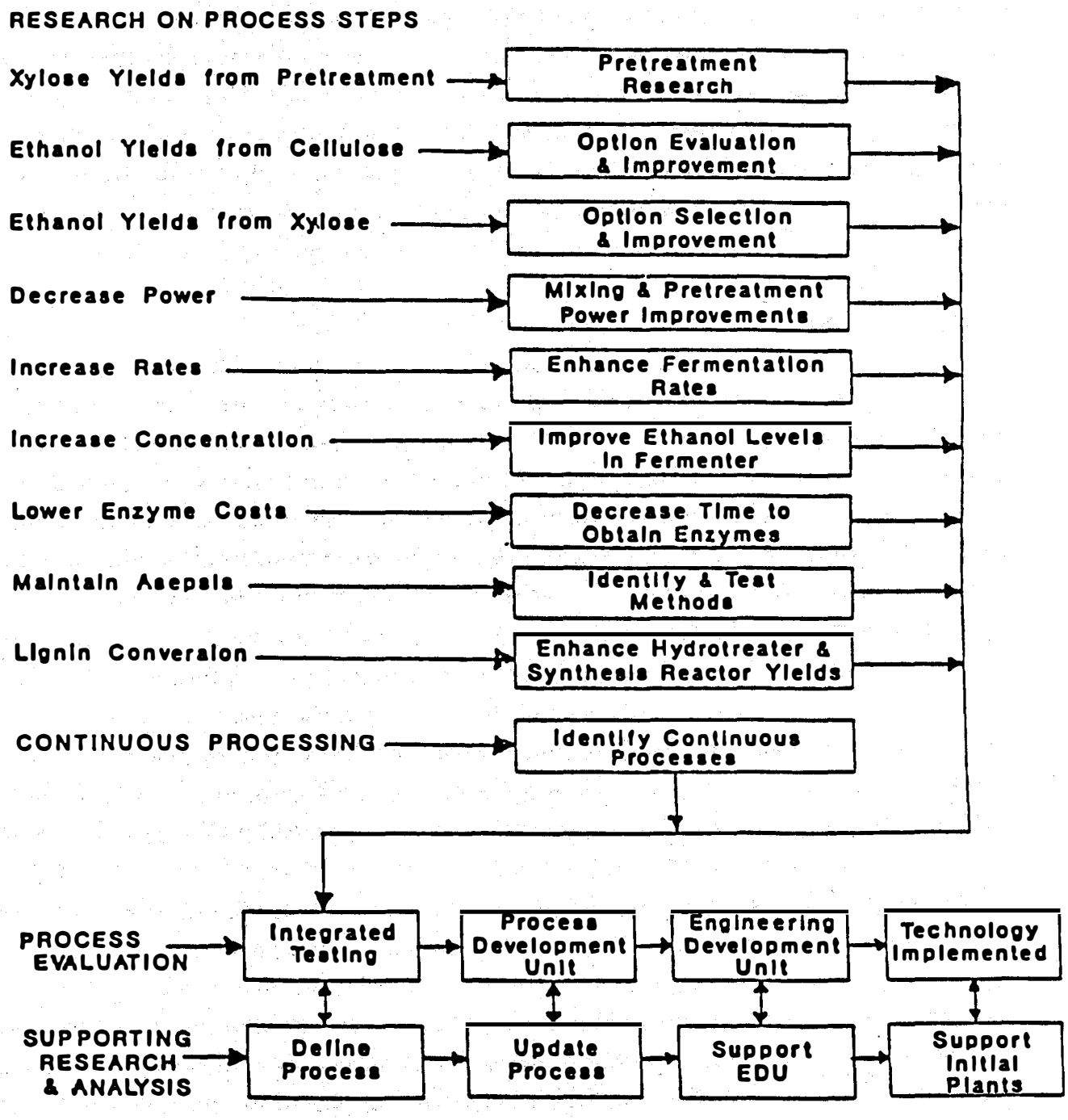


Figure 12. The Relationship of Elements in the Technology Development Pathway

feedstock cost while reducing the amount of unutilized material that must be disposed of.

The second largest fraction of cellulosic biomass is hemicellulose that breaks down to the sugar xylose during the pretreatment step. A few years back, this stream could not be converted into ethanol, hurting revenues while imposing high waste treatment costs. One of the major successes in the last few years has been the development of technology to ferment xylose to ethanol with good yields. Through genetic engineering, a combined enzyme/yeast system was devised that converts 70% of the xylose into ethanol. This single development lowered the selling price of ethanol from cellulosic biomass by $0.30/gallon to $1.35/gallon. Further improvement in the yield of ethanol from xylose to 90% will drop the sales price by another $0.09/gallon.

Significant power has been projected to be required for mixing the SSF reactor and for the pretreatment step. However, preliminary experiments have shown that existing mixing correlations may not properly account for the critical phenomenon in cellulose conversion and that power consumption could be reduced by a factor of 50, saving about $0.13/gallon. In addition, if the pretreatment step could be carried out at high solids levels, less heat would be required, reducing pretreatment energy costs as well.

Increased reaction rates for conversion of cellulose to ethanol are desirable to reduce fermenter volumes and capital costs and to allow economies of scale for larger plants. When the research on SSF was first initiated, about 12 to 14 days were required to achieve 70% yields of ethanol. However, through better choice of pretreatment conditions, improvements in enzyme formulation, careful selection of yeast strains, and changes in operating conditions, yields of 80% are now possible in as little as five days. If the time for fermentations can be reduced to 3 days while maintaining low enzyme addition levels, the price of ethanol can be dropped by $0.09/gallon.

Initially, ethanol concentrations in SSF had to be maintained at low levels of about 2% to achieve high yields. However, through careful selection of the proper combination of pretreatment conditions, enzyme, yeast, and fermenter operating conditions, the ethanol concentrations in SSF's are now about 4%. Although this is closer to the limit of 7-8% required to provide low cost ethanol purification, further reductions in ethanol selling price of about $0.10/gallon are possible if the concentration can be improved to 8%.

The fungus that produces cellulase enzyme must be grown on cellulose, and growth on cellulose is slow. As a result, growth times of about a week are typical, and the production of enzyme is

expensive. Therefore, the primary premise to all of the proceeding activities has been that the use of enzyme should be minimized to maintain low costs. Alternatively, if the enzyme could be produced by a different organism that grows more rapidly, enzyme costs could be dropped enough to allow substantial addition of enzyme to maximize ethanol production rates and yields while maintaining low costs. Success in this area would drop the price of ethanol by up to $0.07/gallon at currently assumed enzyme loadings, but if more enzyme is needed to improve SSF rates and yields, the benefits of this research would be even greater.

For fermentations, unwanted organisms can invade the fermenter, and it is critical that steps be taken to maintain the targeted microbial population through aseptic operation. Although the benefits of aseptic practice can't be directly measured, it can be looked on as analogous to yield loss. For instance, if 50% of the fermentations became contaminated and had to be aborted, the overall product yield would drop by 50%. Thus, since yield is the key factor in determining the selling price of ethanol, aseptic operation must be maintained if targeted selling prices are to be met.

The proceeding research and development will be directed toward continuous processes to the extent possible since they offer higher volumetric productivity and ultimately lower capital costs. However, continuous technology is not commonly practiced in the infant high value, low volume biotechnology industry, and not all process steps can be quickly brought on stream if continuous process development must be completed before pursuing larger scale evaluations. Thus, the baseline technology described previously will be developed to meet the target price of $0.60/gallon with continuous processing applied to steps for which the technology is reasonably well developed. An independent research path will be followed to develop a totally continuous system that has the potential to significantly lower the selling price of ethanol to that expected of a mature process. This sequence will allow application of the baseline technology in a timely manner followed by improvement to continuous processing technology as it is brought on stream.

The lignin left after the biological conversion of the cellulose and hemicellulose into ethanol can be used in two ways that are compatible in volume with a large scale ethanol plant: burned as a boiler fuel or converted into the octane enhancers methyl aryl ether (MAE) or ethyl aryl ether (EAE). If the lignin is burned, more than enough heat can be provided to run the entire ethanol plant. In the second route, the lignin is hydrotreated with hydrogen from a methane reformer, and the oxygenated aromatic compounds formed are reacted with methanol or possibly ethanol to form the corresponding ethers. At oil prices of over $23/barrel, the conversion of lignin into octane

boosters can improve ethanol production economics provided high yields are achieved in the lignin hydrocracker and the ether synthesis reactor yields per pass are raised substantially.

Integrated Process Testing

While the research elements are aimed at improving the performance of the individual process steps, process integration is required to perfect the operation of each step when applied to the actual process conditions and biomass streams. Although total process integration is not possible until research on all of the process steps has been completed, partial integration can be initiated for successive steps starting from the front end of the process, i.e. pretreatment, and working toward the final steps. Proceeding in this fashion makes it possible to accelerate the technology for ethanol without waiting until all research is done before initiating process integration. Integrated Process Testing is carried out with existing bench scale equipment to establish actual performance of the process at modest costs.

Process Development Unit

As the integrated process testing nears completion, a larger scale process development unit (PDU) will be constructed at the smallest scale sufficient to allow operation with equipment that replicates that expected commercially. In particular, each unit will be built to specifications established through research, process engineering analysis, and integrated scale testing; and reliable material and energy balance data will be generated. Any unique individual process steps needed to provide targeted performance will be constructed and operated in conjunction with all other operations. In this way, realistic power consumption measurements can be made for mixing, pretreatment, and other critical steps while stream flows are sufficient to insure that relatively small losses to waste products or vent gases are detected and corrected.

Engineering Development Unit

After the PDU has been operated successfully, the next phase depends largely on the commitment of the industrial firms to commercialization. It is expected that these companies will want to build a larger plant than the PDU at a site of their choosing to prove the process at a semi-commercial scale, the Engineering Development Unit (EDU). Government cost sharing will be important to insure the EDU progress is maintained.

Supporting Research and Analysis

It is important to note that although the emphasis of the Ethanol from Biomass Program will shift from research on individual process steps, to integrated process evaluations, and on to PDU and EDU scale processing, laboratory research will be continued to support this evolution in technology. Significant efforts in this area must be maintained to understand the cause of problems that arise during integrated testing and resolve these issues. There will also be opportunities to improve the performance through application of the continuing advances in the biological sciences and biochemical engineering which should be capitalized on to insure the most cost effective technology is applied to the production of ethanol. Similarly, process engineering studies and analysis must be an ongoing activity of the Program to monitor progress, evaluate emerging technologies, and update financial parameters to reflect changing industrial criteria and economic conditions.

Integration with Low Cost Feedstocks

In addition to the development of technology for production of ethanol from biomass sources expected to be available in abundance, opportunities will be explored that can use low cost feedstocks that may be less plentiful. Also, attention will be focused on applications that could integrate well with an existing ethanol plant to minimize the amount of equipment that must be developed and installed. Since feedstock is the single most costly component of ethanol selling price, this strategy should allow more rapid application of a few process steps than would otherwise be possible and facilitate later commercialization of the overall process by providing operating experience with significant portions of the process.

Research Schedule

A summary of the overall schedule to establish the technology to achieve an ethanol selling price of $0.60/gallon by the year 2000 is shown in Figure 13. As discussed previously, the Accelerated Ethanol R&D is divided into six primary phases: Research on Process Steps, Integrated Process Testing, Process Development Unit (PDU), Engineering Development Unit (EDU), Supporting Research and Analysis, and Integration of Low Cost Feedstocks. This plan does not include Feedstock Production Research which will help achieve the final goal.

Research on Process Steps

The Research element is directed toward improving the performance of the individual process steps to meet performance goals, and considerable progress has already been made through this element. As shown by the research schedule in Figure 13, many of the research activities can be completed in three to four years, and if funding is adequate to carry out the activities outlined in parallel, the overall schedule can be met as shown. Otherwise, attention must be focused on upstream process steps to support time phased integrated testing and PDU experiments followed by other activities as time proceeds. Of course, the overall progress will be delayed accordingly.

Integrated Process Testing

The Integrated Process Testing element is focused on combining the various process steps to evaluate their performance when utilized in real hardware at the smallest possible scale that replicates the sequence of unit operations planned for the commercial unit. It will proceed from the front end of the process, i.e. pretreatment, and move toward the back as rapidly as progress in the research element on each respective process steps allows. Some work has already been completed in this area on feedstock evaluations. In addition to using the baseline technology, this element will test the improvements as they are made. A good deal of the work in this area can be finished within three years, and the full effort will be completed in 1997 if aggressive funding is applied.

Process Development Unit

While the Integrated Process Development phase can make use of much of the existing bench scale equipment, the PDU step utilizes significantly larger and more expensive equipment to provide scaleable data for commercialization. To accelerate progress, this step will proceed in much the same way as for integrated testing, that is, results from the front of the process to the back will be brought on stream as soon as they are available. This strategy will allow the PDU to begin in late 1991 while waiting until the integrated testing is complete would delay the start of this effort until late 1997.

Engineering Development Unit

Finally, if needed, the EDU is paid for primarily by industry with cost sharing by DOE to prove the

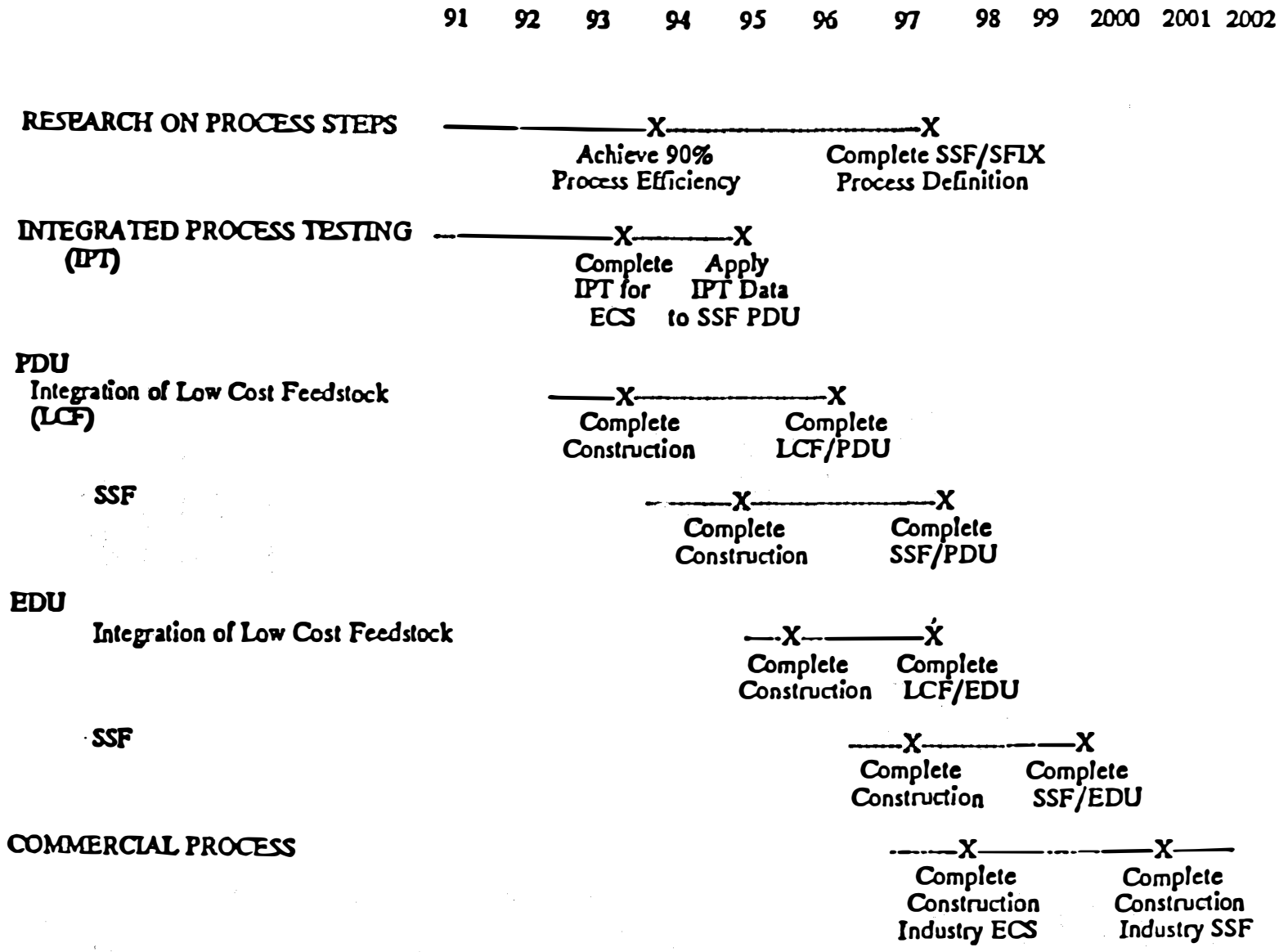


Figure 13. The Overall Research Schedule Is Focused on Achieving Technology for Production of Ethanol for $0.60/Gallon in 2000

performance of the overall process on a small plant scale. It is planned that enough of the integrated testing and PDU elements will be completed by 1998 to initiate solicitation of active industrial partners for the EDU. Those firms involved in the PDU are particularly appropriate candidates.

Supporting Research and Analysis

The Supporting Research and Analysis element is maintained throughout the other phases to solve problems that arise as the larger scale evaluations proceed, insure that new developments are utilized to improve the process as possible, and update economic evaluations of the technology.

Integration of Low Cost Feedstocks

The relationship of the plan for integration of low cost feedstocks to the overall plan is given in Figure 11 as well. This element will begin with identification of promising low value or waste streams through process analyses and discussions with industrial firms. It will then proceed on to testing of the ethanol yields from these feedstocks, through integrated testing, and into PDU and EDU experiments in cooperation with industry.

Implicit Production Levels

The current production level of ethanol from corn is about 850 million gallons per year with a capacity of approximately 1.0 billion gallons now in place. In the near term, up to about another 5 billion gallons of ethanol could be produced from corn, although excise tax exemptions would continue to be required to maintain the market for ethanol. Furthermore, the USDA has projected that the price of corn would increase as the amount of ethanol produced from corn increased. As markets for corn ethanol by-products eventually became saturated, price discounting would likely result as ethanol producers attempted to sell excess by-products. Since the cost of corn or other starch crops and the selling price of by-products are the dominant factors in determining the selling price of ethanol, the price of ethanol would no doubt have to increase with volume if the industry is to see continued expansion. To some extent, this could be countered by improvements in the technology, but it is expected that the cost of production could not be lowered enough through technology advances to counter the dominance of by-product and corn prices in determining the economics of ethanol production. Thus, although ethanol production from corn provides a valuable means to supply ethanol in the near term, it is unlikely to be able to meet a

major market for ethanol.

Production of ethanol from cellulosic feedstocks is currently not commercial. However, as the technology is advanced to produce ethanol from these low-cost and abundant materials, applications should develop for cellulosic materials that are now wasted. Examples could include waste paper, corn cobs and other agricultural residues, forestry wastes, and leftover carbohydrates in animal feed by-products in the wet and dry milling of corn. Since such materials are underutilized and have a zero or very low value, conversion to ethanol could be carried out below the selling price of corn ethanol, providing a near term opportunity to introduce the technology into the marketplace. Such uses would facilitate the later introduction of the technology targeted for ethanol production at prices competitive with gasoline.

A process for conversion of cellulosic biomass into ethanol will utilize standard equipment for fermenters, pumps, tanks, product recovery, and so forth, and as a result, little economic benefit is gained with the scale of production from the viewpoint of the assembly of equipment. However, one can expect reductions in the cost of the ethanol production related to process configuration and equipment design as we advance along the learning curve with increasing numbers of plants. Furthermore, the technology can also gain from economies of scale, since plant costs generally rise at a less than linear rate with increasing size. On the other hand, the cost of feedstock will begin to increase as the plant reaches some critical size, and at some point, the increasing cost of feedstock will outweigh the decreasing cost of the plant. These tradeoffs are site specific, and a range of plant sizes are expected to result, just as for ethanol production from corn and petroleum refinery operation.

Once the technology is developed for production of ethanol from cellulosic biomass at the target price, it should be possible to maintain the low price even at high production levels. First, the ultimate by-products for the conversion process are lignin conversion to boiler fuel to run the process and ethers for blending with gasoline. Since these markets are comparable in size to the market for ethanol, no price squeeze is anticipated with increasing ethanol capacity. Second, the feedstock is sufficient to produce enough ethanol to replace gasoline twice over, and as a result, the cost of cellulosic feedstock should remain quite flat at the expected production level. Third, unlike sugar used for production of ethanol in Brazil, cellulosic biomass has no higher value, large scale markets such as food to compete with ethanol production for the feedstock.

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Section 9

TECHNOLOGY EVOLUTION RATIONALE FOR METHANOL TECHNOLOGY

October 5, 1990

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DRAFT

Draft - Technology Rationale for Biomass to Methanol

Preface

This paper is intended to support the base case biomass to methanol cost and performance projections for the National Energy Strategy. The paper reviews the technologies and costs of thermochemical production of methanol. Gasification of biomass to produce a synthesis gas followed by catalytic methanol synthesis is the primary technology selected for development based on the current state of the art, the potential for short term impact, and the significant level of industrial interest. In 1990 the cost of methanol from biomass is estimated at about $16.00 per Mil BTU ($0.96 per gallon) for a 2,000 ton wood per day facility. This paper discusses the technical rationale for achieving substantial reductions in the cost of production. Projections made for a business as usual development program show the cost of energy being reduced to $10.25 per Mil BTU ($ 0.62 per gallon) by the year 2010. An accelerated development program may reach this same objective by the year 2000. Other process improvements, if successfully developed and demonstrated, have the potential to reduce the cost of methanol to $7.75 per Mil BTU ($0.47 per gallon). Larger scale commercial plants, e.g. 10,000 tons per day, may have methanol cost of production values as low as $5.55 per Mil BTU ($0.33 per gallon).

Introduction

Technology Description

The thermochemical production of methanol from biomass involves the production of a synthesis gas rich in hydrogen and carbon monoxide which is then catalytically converted into methanol. Production of the synthesis gas is accomplished by thermal gasification.

The unit operations involved in methanol production from biomass are divided into the following major areas:

- Feed Preparation
- Gasification
- Synthesis Gas Modification
- Methanol Synthesis and Purification

A typical process flowsheet is shown in Figure 1; in this figure raw gas cleanup, CO shift, and acid gas removal make up the synthesis gas modification block.

In order to understand the need for these processing steps a brief discussion of the chemistry of methanol production is required. Wood will be used as a typical biomass feedstock. Wood is a complex mixture[1] of organic compounds and polymers. The major types of compounds are lignin and carbohydrates(cellulose and hemicellulose) whose ratios and resulting properties are species dependent. Lignin, the cementing agent for cellulose is a complex polymer of phenylpropane units. Cellulose is a polymer formed from d(+)-glucose while the hemicellulose polymer is based on hexose and pentose sugars. Wood has low ash, nitrogen, and sulfur contents. In order to estimate yields during gasification the complex

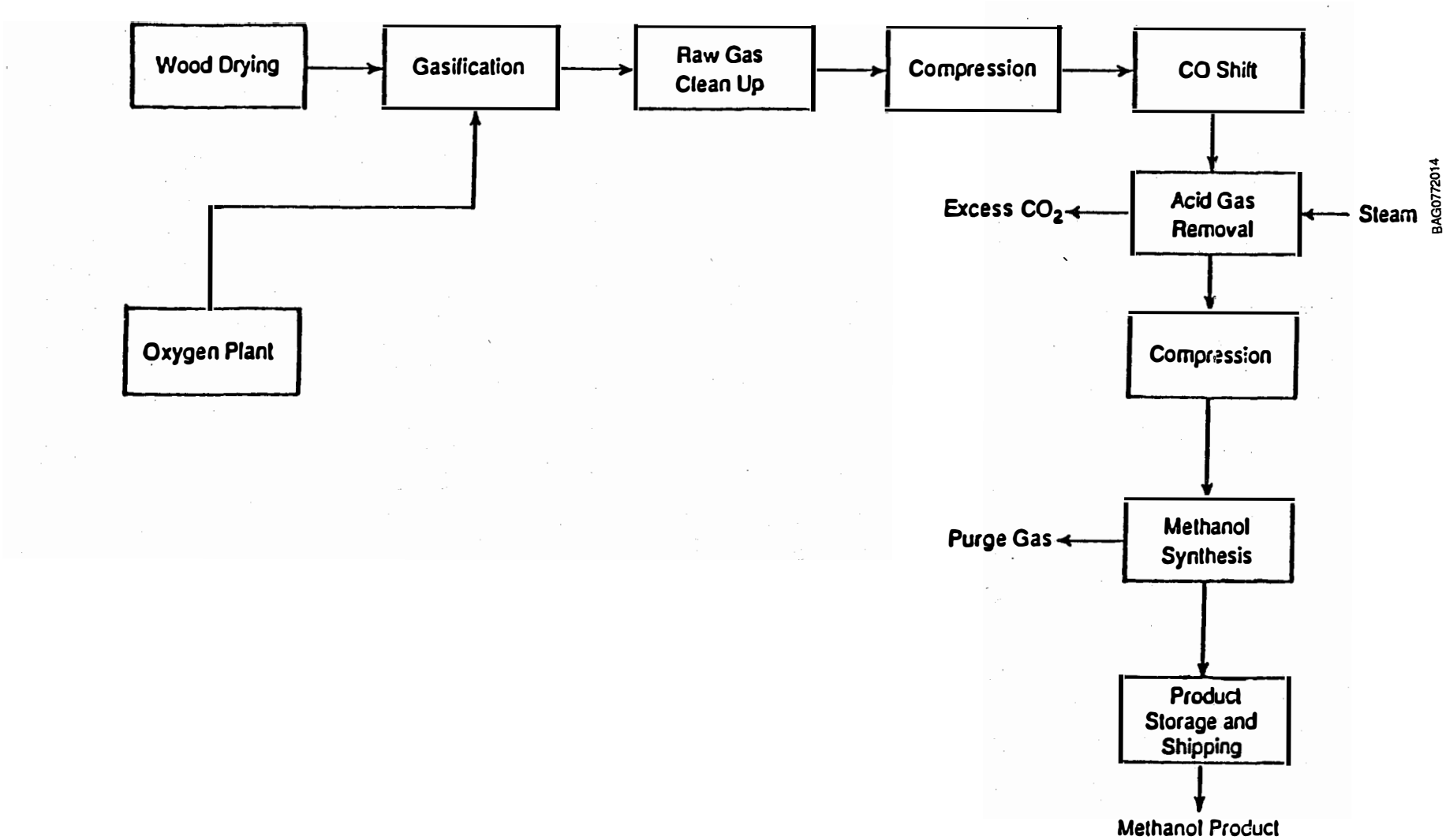

Figure 1. Simplified Wood to Methanol Process Configuration

material must be reduced to a simple chemical formula. Wood can be represented by the following simplified formula, $CH_{1.4}O_{0.6}$. Elements such as sulfur and nitrogen are present in very small amounts and do not need to be considered in terms of overall chemistry.

Combustion of wood can be ideally represented by:

$$CH_{1.4}O_{0.6} + 1.05\ O_2 \ \text{---->}\ CO_2 + 0.7\ H_2O \qquad (1)$$

Oxygen gasification can be thought of as incomplete combustion. Gasification using a minimum amount of oxygen can be represented by:

$$CH_{1.4}O_{0.6} + 0.2\ O_2 \ \text{---->}\ CO + 0.7\ H_2 \qquad (2)$$

In cases where no oxygen is used an "ideal" gasification reaction can be represented by:

$$CH_{1.4}O_{0.6} \ \text{---->}\ 0.6\ CO + 0.4\ C + 0.7\ H_2 \qquad (3)$$

The cracking reaction is endothermic and heat is needed to make the reaction proceed.

While these ideal reactions are simple, actual gasification is more complex and intermediate compounds such as tars and methane are formed which must be further processed before the synthesis gas can be used to produce methanol. Methanol is formed catalytically by the following reaction:

$$CO + 2\ H_2 \quad \text{<--->} \quad CH_3OH \qquad (4)$$

It can be seen that two molecules of hydrogen are required for each molecule of carbon monoxide. Gasification may produce a gas with a hydrogen to carbon monoxide ratio as low as one-half. In this case water is added and some of the carbon monoxide is used to produce hydrogen by the catalytic shift conversion reaction:

$$CO + H_2O \quad \text{---->} \quad CO_2 + H_2 \qquad (5)$$

The methanol synthesis reaction is an equilibrium reaction and does not proceed to completion. In order to obtain economic yields unreacted gas is recycled to the synthesis reactor. While not harmful in terms of chemistry, inert gases such as methane must be purged from the system, resulting in loss of yield and an economic penalty. Concentrations of methane larger than one or two percent typically result in unacceptable economic penalties. Therefore, synthesis gases containing high levels of methane are steam reformed prior to methanol synthesis. The primary catalytic reforming reaction is:

$$CH_4 + H_2O \quad \text{---->} \quad CO + 3\ H_2 \qquad (6)$$

In addition the shift conversion reaction shown above also occurs in the reformer.

Carbon dioxide can also react with hydrogen to produce methanol, but consumes more hydrogen per mole of methanol formed than when using carbon monoxide. Most of the carbon dioxide is therefore removed from the synthesis gas prior to

methanol synthesis.

With this knowledge of chemistry as a basis the unit operations can be discussed. Figure 2 shows the major routes for production of methanol from biomass on a simplified basis. Figure 1 is a more detailed version of the low pressure oxygen route shown in Figure 2. These routes differ primarily in the type of gasification process chosen.

The feed preparation section of a biomass to methanol process involves wood storage and handling, size reduction, and drying. Size reduction is process specific. Drying is performed to minimize feed degradation during storage and to optimize the overall process energy balance.

Gasifiers can be divided into three major classes:

- air gasifiers
- oxygen gasifiers
- indirect gasifiers

This classification is based primarily upon the method of supplying the heat necessary to drive the endothermic pyrolysis reactions, the carbon-steam reaction and the carbon-carbon dioxide reaction. Gasification is an old technology for converting coal and biomass into a gas which can be used in various technical processes. Coal gasification is commercial technology used to produce substitute natural gas (Great Plains), gasoline and diesel fuel (Sasol), and methanol (Tennessee Eastman as an intermediate in acetic anhydride production and SASOL as an intermediate in formaldehyde production). Biomass gasification was used

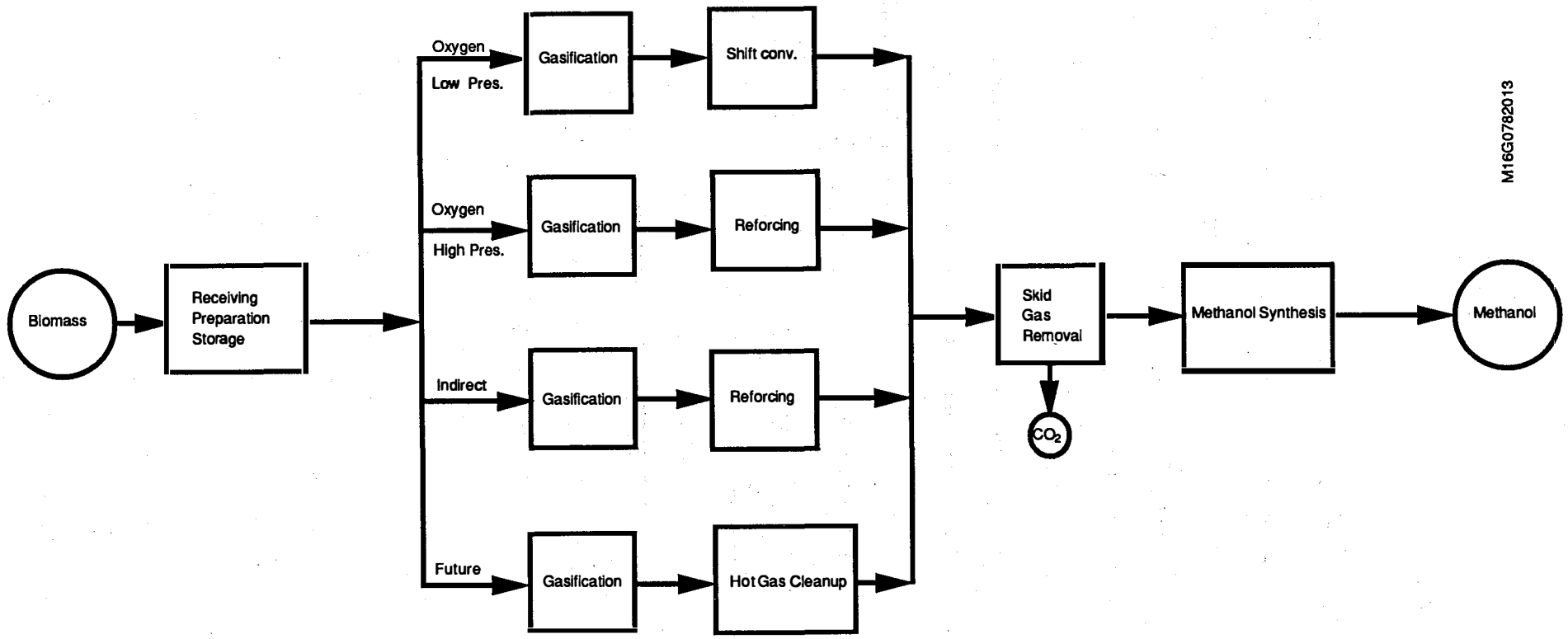

Figure 2. The Chemical Routes to Methanol From Biomass

in Europe during World War II to supply energy for transportation, electricity and heat.

Biomass gasification has not been commercially developed in this country because of the abundant supplies of natural gas, petroleum, and coal. Because of the differences between coal and biomass, coal gasifiers are not directly usable for biomass gasification. Differences in reactivity (with biomass being more reactive) change required operating temperatures, pressures, and residence times. Differences in density between coal and biomass requires modification of the solids feeding systems. The ancillary facilities, such as utilities and waste treatment can be applied to biomass gasification except that biomass gasifiers do not require as extensive clean up for sulfur or nitrogen derived compound emissions as coal gasifiers because of the low sulfur and nitrogen content of wood. A number of gasifiers are being developed in this country, in Canada,in Europe, and in other countries to process biomass. Because of the high reactivity of biomass they are typically operated at lower temperatures than are coal gasifiers. To date, gasifier development has concentrated on production of a medium BTU gas for use in electrical generation and as a substitute natural gas. Development has not been specific for methanol production.

Air gasifiers use air to provide process heat. A portion of the feed is burned, and the heat of combustion is used to gasify the remaining feed. The nitrogen present in air acts as a diluent in methanol production and leads to very unattractive economics. Air gasification product can be used for electricity generation, and for ammonia synthesis.

In order to reduce the amount of inert gas in the gasifier product stream

relatively pure oxygen can be used in place of air. While the use of oxygen will produce a gas suitable for downstream synthesis gas processing, oxygen is expensive and accounts for a large percentage of plant capital and operating costs. For example, oxygen costs $40 to $60 dollars per ton, and is typically used at the rate of 0.25 to 0.35 ton oxygen per ton of biomass in oxygen gasification. This translates to $10 to $21 per ton of biomass processed.

Oxygen gasifiers are operated at both low and high pressure. The primary low pressure oxygen (LPO) gasifer presently being evaluated for biomass gasification is the Koppers-Totzek (K-T) gasifier. The K-T gasifier[2,3] is an entrained flow gasifier whose operation requires that the biomass be ground very fine, minus 30 mesh (minus ca. 0.02 inches). The required comminution adds appreciably to feed preparation costs. Operation at low pressure in the presence of oxygen produces little methane and tars. The hydrogen to carbon monoxide ratio is less than one, comparable that of indirect gasifiers. The Union Carbide Corporation Purox[4] process has been developed for municipal solid waste gasification. The hydrogen to carbon monoxide ratio in the produced gas is also less than one.

High pressure oxygen (HPO) gasifiers are being developed to improve on the economics of LPO gasifiers. Typically these gasifiers are fluid bed gasifiers which are fed fairly large wood chips, e.g. minus 2 inches. Oxygen and steam are injected near or at the bottom of the reactor and react with the wood, char and synthesis gas. Fluid bed reactors have the advantage of good mixing of the feed solids, uniform bed temperature, and rapid equilibrium between solids and gases. However, operation at high pressure favors the formation of methane. Operation at high pressure reduces gasifier capital cost and downstream compression costs, but downstream processing to remove or reform tars and methane adds appreciably

to capital and operating costs. The Winkler and Institute of Gas Technology (IGT) gasifiers are representative of HPO fluid bed gasifiers. The Texaco gasifier is a representative HPO entrained flow gasifier. The Winkler and Texaco gasifiers have been developed for coal. The IGT gasifier[5] is designed for biomass operation and has been operated at the twelve ton per day scale.

Indirect (IND) gasifiers produce a solid carbon-rich char, see equation 3, which is reacted with air in a separate combustor to provide process heat. This heat is transferred to the gasifier by circulation of hot inert solids, or by indirect heat transfer through the walls of the gasifier or through the walls of heat exchange tubes. IND gasifiers typically produce a synthesis gas rich in carbon monoxide, and with low carbon dioxide levels. In order to produce sufficient char to provide all the heat necessary for gasification these gasifiers are normally operated at relatively low temperatures, 1300 to 1600 °F. At these temperatures synthesis gas yields are reduced and methane concentration is high. The addition of a catalyst may improve the hydrogen to carbon monoxide ratio substantially. Downstream reforming is required for methanol synthesis. Operation of developmental reactors has been directed to production of medium BTU gas, not toward methanol synthesis gas production. The Battelle-Columbus Laboratory (BCL) gasifier[6] and the University of Missouri-Rolla (UMR) gasifier[7] are typical of IND gasifiers developed for biomass processing. Both of these gasifiers have been operated at the pilot scale.

The synthesis gas exiting the gasifier contains small amounts of tar and char which must be removed prior to downstream catalytic conversion operations. Typically, gasification systems use scrubbers to remove tars. While efficient in contaminant removal scrubbers produce a dirty water stream which must be further

processed. An alternative to scrubbing is hot gas cleanup. In coal gasification systems operated at high temperature tar removal is generally not required, and hot gas cleanup is directed toward removal of sulfur compounds. Hot gas cleanup systems are being developed for biomass gasifiers in Europe. The Studsvik MINO process[8] in Sweden includes a catalytic tar conversion operation and has been operated at a pilot scale. In France the Cruesot Loire system[9] uses a thermal tar conversion reactor. Research is ongoing in the United States in the area of hot gas cleanup for biomass gasifiers, but pilot operations have not been undertaken to date.

All unit operations downstream of the gas cleanup operation are commercial technology and require no major development. Steam-methane and steam-naphtha reformers are the primary method of production of hydrogen by the petroleum industry and have been operated for many years. Likewise, shift conversion reactors have been operated commercially for many years as a part of steam-reformer systems. In 1989 approximately 7,345 million gallons of methanol production capacity existed worldwide[10] using thermal conversion operations. Eighty-six percent of this production capacity uses steam-reforming operations followed by catalytic methanol synthesis. The primary commercial methanol synthesis processes are licensed by ICI and Lurgi.

Research is ongoing for development of improved methanol and mixed alcohol synthesis processes. As discussed later, successful development of one or more of these processes may improve biomass to methanol economics, but is not required for process commercialization.

Technology Application/Users

The primary present market for methanol is the chemicals industry. It is projected[9] that in 1990 the global demand for methanol will be 5,990 million gallons. Of this amount 2,240 million gallons will be used for formaldehyde production, 470 million gallons for acetic acid production, 940 million gallons for MTBE production, and 2,340 million gallons for other uses. The use of methanol as a MTBE feed can be considered a transportation use, since the primary use of MTBE is as a gasoline additive. If methanol is used as fuel starting in the mid-90's consumption may grow to 335 million gallons per year by the year 2000 using a moderate fuel use growth scenario, and to 3,680 million gallons per year using an accelerated fuel scenario. In addition MTBE use will grow to 2,860 million gallons per year over the same time frame. Total demand will grow to 13,720 and 16,730 million gallons per year, respectively. The transportation sector usage will grow from its present 16 percent of usage to between 23 and 39 percent of usage.

On a short term basis, other predictions[11] show United States methanol demand rising from 1,650 million gallons in 1989 to 2,130 million gallons in 1992, with the largest increase being for MTBE production. Present methanol cost is $0.40 per gallon, FOB producing point, Gulf Coast[12] ($6.67/ Mil BTU @ 60,000 BTU/gal).

The primary users of a Biomass to Methanol Process will be industrial concerns wanting to compete in this large and growing methanol market. The users will probably not have access to inexpensive sources of natural gas. In order for industry to show any interest in this type of process it needs to be demonstrated that methanol production from biomass can compete economically with methanol from natural gas using reasonable estimates of future natural gas prices. Unless this

can be shown there will be no interest by industry. In addition, a realistic development time line for technology commercialization is seven to ten years. Industry is not willing to invest large amounts of money in high risk development for long term projects. Government support or incentives will be needed for technology development in the short term to supply the initial venture capital needed to have a process commercially demonstrated by the year 2000.

Resource

Refer to Appendix

Cost/Performance Projections

Recent Technical Progress and Status

Technical development efforts for production of methanol from biomass are concentrated in the area of gasification. As stated before these efforts are primarily directed toward production of medium BTU gas for electrical generation or for fuel use and not for synthesis gas production. However, results obtained are directly applicable to gasification for methanol production. Gasification systems are being developed in the United States, in Canada, and in Europe. This paper will concentrate on biomass gasifiers being developed in the United States.

Five gasifier systems are actively being developed in the United States for biomass gasification. These systems are listed below:

- Battelle Columbus Laboratories (BCL)
- Institute of Gas Technology (IGT)
- Manufacturing and Technology Conversion International Incorporated (MTCI)
- Syngas, Inc. (SGI)
- University of Missouri-Rolla (UMR)

In addition a number of other systems have been developed to the pilot or demonstration scale, but are not discussed in this paper. A partial list is given below:

Process	Feed

American Thermogen	Municipal Solid Waste (MSW)
Cruesot Loire (France)	Wood
Davy McKee	Wood
HTW (Germany)	Peat, Lignite
MINO (Studsvik, Sweden)	Wood
Omnifuel (Canada)	Wood
Pacific Northwest Laboratory	Wood
Pillard (France)	Vegetable wastes
Twente (Netherlands)	Wood
Purox (Union Carbide)	MSW
Wellman Galusha	Wood

BCL Gasifier

The BCL gasifier system[5] is a dual bed IND gasifier system operated in an entrained flow mode. Heat for gasification is supplied by hot sand recirculating between a separate combustion vessel and the gasifier. Residual char remaining after gasification of the wood provides the fuel for the gasifier. The system has been operated at a 25 ton per day scale in pilot plant operation. The gasifier produces a synthesis gas with a low hydrogen to carbon ratio, high methane content and some tars. For methanol production the tars will have to be removed and the methane reformed to produce a suitable synthesis gas. The pilot system has been operated under conditions giving energy self sufficiency on a gasifier stand alone basis. No integrated methanol synthesis plant systems analysis studies have been published. It is possible that higher temperature operations are possible in an integrated plant where a portion of purge gases from the methanol synthesis loop can be used to make up shortfalls in heat

available from char combustion. At higher temperatures tar yield and methane content will both be reduced.

IGT Gasifier

The IGT gasifier[6] is a HPO gasifier operated in the fluid bed mode. Oxygen and steam are introduced near the bottom of the fluid bed reactor. Oxygen reacts with a portion of the feed and gasification products to supply the heat required for gasification. The system is designed to produce a medium BTU gas from biomass at moderate temperatures, 1400 to 1800 °F and high pressures, 100 to 350 psia. The IGT gasifier has been operated at a 12 tons per day scale. The product gas is high in methane and contains some tars. For methanol production tars will have to be removed and the gas reformed to reduce the methane concentration.

MTCI Gasifier

The MTCI gasifier[13] is an IND gasifier operated in the fluid bed mode at moderate temperatures, ca. 1200 to 1300 °F and atmospheric pressure. Heat for the gasification reaction is supplied indirectly through heat exchange tubes placed in the fluid bed. A pulse combustion system is used to increase the rate of heat transfer from the combustion flue gas to the fluid bed. To date natural gas has been used as the fuel for combustion, but a portion of the produced gas would probably be used for commercial operations. In addition to the high heat transfer rate, operation of the system is characterized by the use of a catalytic fluidization solid which results in product gases having high hydrogen to carbon monoxide ratios. As for the previous gasifiers the product gas contains methane

and tars and will require cleanup and reforming in commercial operations. Only limited pilot runs have been performed at a 0.4 ton per day scale. For methanol production tars will have to removed, and the gas reformed to produce a suitable synthesis gas, assuming operation at conditions comparable pilot operation conditions.

SGI Gasifier

The SGI gasifier is a stratified downdraft gasifier which can be operated using air or oxygen as a LPO or HPO gasifier. The system has been operated on a limited basis as a HPO gasifier at the 24 ton per day scale. Original development of the gasifier was performed by the Solar Energy Research Institute from 1981 to 1985. The technology was licensed to SynGas, Inc., in the mid 80's for commercial development. The unit operates as a moving bed gasifier with co-current flow of oxygen or air in a downward direction. The design produces a minimum of tars. The system is designed to produce a low to medium BTU fuel gas and has not been operated at optimal conditions for methanol production. The gasifier produces a low hydrogen to CO ratio, some methane, and some tars.

UMR Gasifier

The UMR gasifier is an IND gasifier operated as a fluid bed reactor with heat supplied via heat exchanger tubes internal to the bed. Heat is supplied by high temperature combustion flue gas. In pilot operations natural gas has been used for combustion fuel, but in commercial operation char or a portion of gasifier product gas would be used. The system has been operated at the 3.6 short ton per day scale at relatively low temperatures. Operation at low temperatures gives

higher char and tar yields and lower gas yields than the other gasifiers under development. Temperature may be limited by maximum indirect heat transfer rates. The gas will have to be reformed and tar destruction will be required to make a suitable synthesis gas feed. Because of operation at low temperature the tar production in this gasifier is an order of magnitude larger than in the other gasifiers. Higher temperature or catalytic bed operation of the system would produce a product stream similar to that of the MTGI gasifier.

To summarize technology status, a number of gasifiers are under development which have the potential to produce a synthesis gas suitable for methanol synthesis. These gasifiers are operating in the 4 to 25 ton per day scale. All systems under development are designed to produce a low to medium BTU fuel gas. None of the systems have been operated on an integrated process basis to determine operating parameters necessary for maximum methanol production. All downstream synthesis gas operations are commercial technology in which operating conditions and yields are known.

Market Acceptance

The present market price of methanol is $0.40 per gallon. Cost estimates for methanol production from biomass range from $ 0.70 to $1.30 per gallon using various gasifiers and yield estimates. These estimates are based in most part on pilot plant data obtained under conditions not optimal for methanol production. Operation of plants under conditions designed to maximize methanol yield should reduce these costs substantially. As stated before, the market for these systems will be large industrial firms wanting to produce methanol. In order for biomass to methanol processes to be commercially developed it must be

shown that methanol production from biomass is competitive with methanol from other sources such as natural gas. If industrial involvement is desired in a 1990 time frame then the predicted cost must be reduced to the $0.40 per gallon range, or other incentives must be offered to reduce the net cost to this range. Even if this is accomplished, commercial operations will be in the 2,000 to 10,000 ton per day range. At least one intermediate scale of operation, e.g. 100 to 200 ton per day, will be required as an intermediate scale of operation. Substantial government support will be required to progress through this stage of development, given the projected costs and the amount of R & D to be accomplished.

Figures of Merit

The major new growth market for methanol is projected to be in the transportation fuel market, either as a direct substitute for gasoline or indirectly as a MTBE feedstock. Therefore, cost of production values are presented in terms consistent with the energy value of transportation fuels, that is, dollars per million BTU. A dollar per million BTU basis is used instead of a dollar per gallon basis because of the differences in volumetric energy content of the various potential transportation fuels such as methanol, MTBE, gasoline, diesel fuel, and ethanol.

Key Figures of Merit:

- Cost of Energy ($/Mil BTU) - The cost of energy value summarizes the total cost of production of methanol,expressed as dollars per Million BTU. Included in this value are capital recovery, operating

and maintenance costs, replacement costs and feed costs. The capital recovery includes return on investment.

- Plant Capacity (Dry tons/day) - Plant size is defined in terms of the amount of feed, on a dry basis. Other figures of merit are based on a plant capacity of 2,000 dry tons per day of feed.

- Production (Mil gal/yr) - Plant production is defined in terms of millions of gallon per year of methanol. It may also be expressed in metric tons per stream day for comparison with foreign production.

- Installed Cost per Unit of Design Capacity ($/daily ton) - Capital cost is defined in terms of daily feed to the process.

- Operating and Maintenance Cost (($/daily ton) - Operating & maintenance costs account for all costs associated with plant operations, except for feedstock costs. O & M costs are defined in terms of daily feed to the process.

- Feedstock Cost ($/MM BTU or $/daily ton) - Feed costs are defined in terms of daily feed to the process and in terms of dollars per million BTU.

- Availability (Percent) - The plant availability, or stream factor is defined in terms of the percentage of time the plant is operating. As a point of reference a 90 percent stream factor is typical in the

chemicals industry.

Cost and Performance Goals

The 1990 technology cost and performance estimates, as shown in Figure 3, are based upon a number of biomass to methanol studies performed in recent years by a number of organizations. As such they represent a generic gasifier system followed by commercial downstream gas processing and synthesis operations. Ultimate methanol yields are based on experimental and pilot gasifier yields obtained under conditions designed to produce a high quality fuel gas, that is, conditions which will produce a fuel gas containing as much methane as possible, and have not been optimized for methanol production. A seventy-five percent availability was used to indicate a first of a kind plant based only on small 25 ton per day pilot plant data. Detailed costs and production rates are presented in the Science Applications International Corporation[14] (SAIC) study.

With continued research and development costs are expected to be reduced substantially. Table 1 presents individual process improvements, their anticipated cost impact, and an order of magnitude probability of success.
A gasifier demonstration at a larger scale (for example, 100 tons per day) with at least a portion of the operation dedicated to synthesis gas production will improve process performance in two ways. First operation under optimal synthesis gas conditions will improve yield substantially. Secondly operation at larger scale will improve the reliability and therefore the on-stream efficiency of the first commercial plant. The magnitude of these improvements has been estimated at $2.80 per million BTU using an increase in thermal efficiency from 47 to 52

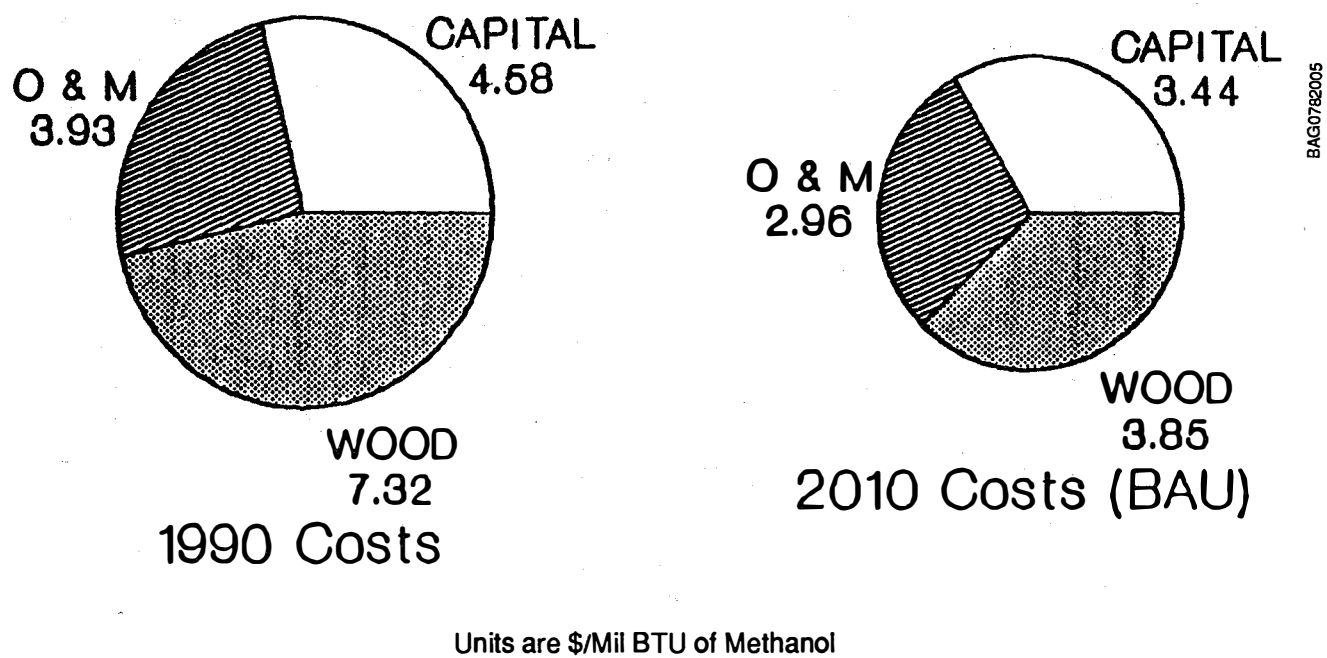

Figure 3. Comparative Costs Biomass to Methanol - Region 6.

Table 1. Impact of Process Improvements on Cost of Production Biomass to Methanol in Region 6

ITEM	COST IMPACT ($/Mil BTU)	RESULTING COST ($/Mil BTU)	RESULTING COST ($/GAL)	PROBABILITY OF SUCCESS (%)
2,000 TPD 1990 Process		15.83	0.95	
Larger Scale Demonstration	-2.11	13.72	0.82	80
Reduction in Wood Cost to $2.00	-3.47	10.25	0.62	90
Hot Gas Cleanup (HGC)	-2.50	7.75	0.47	50
Single Pass Methanol (SPM)	-1.00	9.25	0.56	50
10,000 TPD Plant (Using HGC)	-2.20	5.55	0.33	45
10,000 TPD Plant (Using SPM)	-2.20	7.05	0.42	45
June, 1990 cost from natural gas		6.67	0.40	

percent and an increase in on-stream efficiency from 75 to 90 percent. In addition wood costs are expected to decrease to $2.00 per million BTU as production of energy crops becomes more widespread and efficient. The impact of these improvements reduces the cost of production to $10.25 per million BTU of methanol. Using a 60,000 BTU/gal energy content this price is equivalent to methanol at $0.62 per gallon

In addition to the process improvements to be gained from optimization of yield and increased reliability there are other possible research and development derived improvements which may further reduce production costs, for example, hot gas cleanup and single pass methanol synthesis. These particular process improvements are not additive. Both processes have the objective of eliminating reforming operations. In a hot gas cleanup operation the objective is to destroy tars, reduce methane to acceptable synthesis gas levels, and to adjust the hydrogen to carbon monoxide level for improved yield. In this estimate 40 percent of the reduction comes from elimination of catalytic reforming and 60 percent from a 15 percent additional increase in yield. A high conversion single pass methanol process will eliminate the reformer, but will not increase yield, thus the $1.00 per million BTU impact. If successful, these additional improvements may reduce methanol costs to the range of $7.75 to $9.25 per million BTU (0.47 to 0.56 $/gallon at 60,000 BTU/gal). These process improvements were not included in SAIC cost projections because of the lower probability of success.

In addition to these process improvements a reduction in cost of production can be obtained by increasing the plant size. An increase in plant scale to 10,000 tons per day is estimated to reduce cost of production by about $2.20 per million

BTU. Figure 4 shows the impact of individual process improvements on a cumulative basis assuming success in each step. The large plant is not included in the base case cost projections.

Base Conditions, Relationships, and R & D Opportunities

Base Case

The base case presented in the SAIC study assumes that R & D funding continues on a business as usual (BAU) basis. The projected Federal funding level under a BAU scenario is about three million dollars per year. At this funding level a gasifier demonstration plant can be built and operated, assuming private industry or state cost sharing. At this funding level the demonstration plant will include feed preparation, gasification, and gas scrubbing. An integrated methanol production train will not be included. The base case improvement obtained by operation of a demonstration plant assumes no new technical improvements in gasifier technology, only optimization of gas composition and improved reliability. As such, the probability of obtaining a substantial reduction in cost of production is very high. Very little funding will be available for feed research during the demonstration time frame (five years), so major funding for biomass production at the 3 million dollar level will come in years 6 and later. Much of the improvement in feed costs is assumed to come from funding for associated biomass programs.

Implicit Production Levels

The base case analysis is based on a pioneer commercial plant at the 2000 short

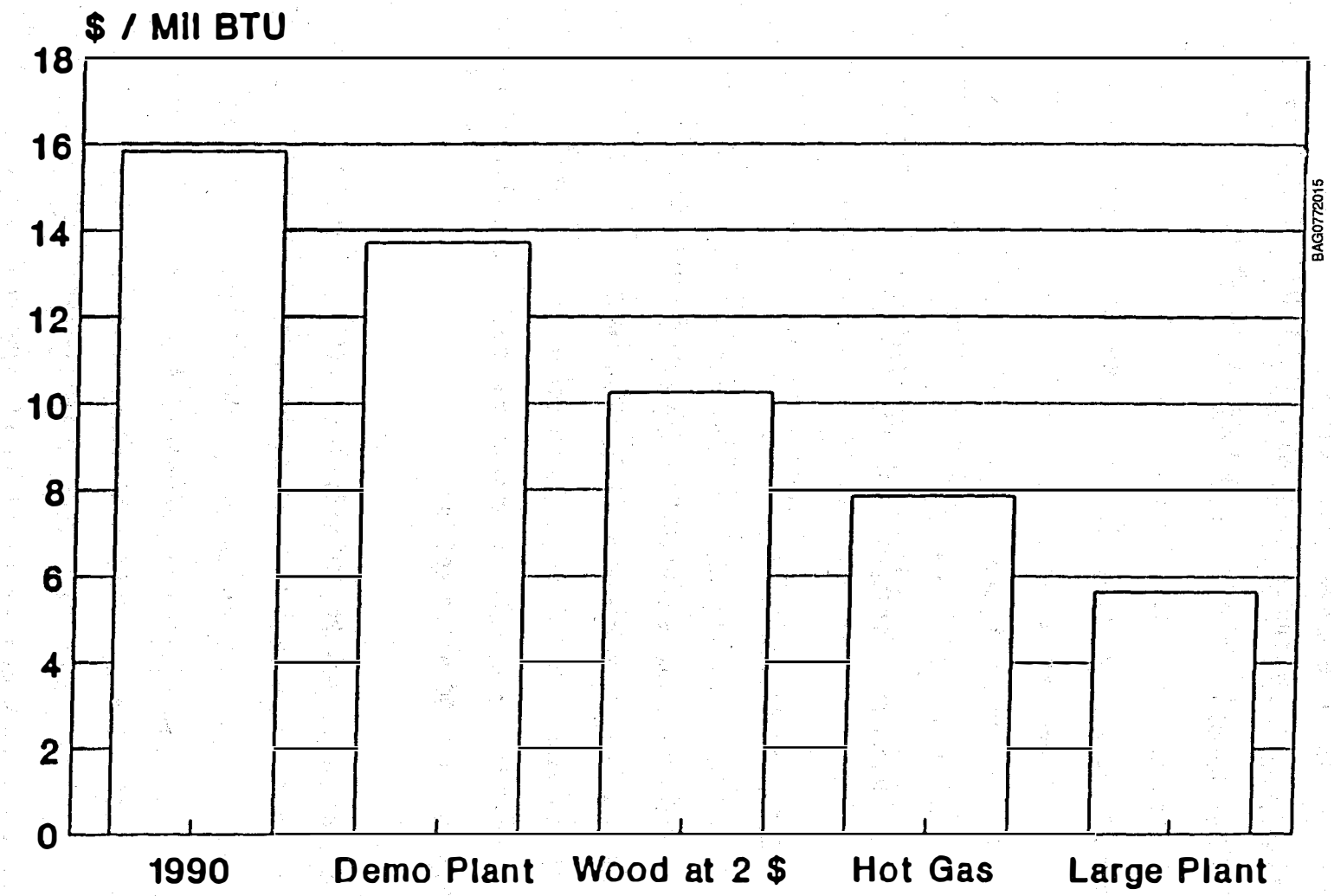

Figure 4. Cost of Production
Biomass to Methanol

ton per day scale. Assuming that the demonstration plant is built and operated the projected production rate of a 2,000 short ton per plant is estimated at 97 million gallons of methanol per year. This production level represents 6 percent of the 1989 U. S. methanol demand. If methanol demand grows by the 250 to 300 percent projected by the year 2000, then one plant would represent only two percent of methanol demand. As stated earlier, it is anticipated that increasing the plant size to 10,000 short ton per days will result in a decrease in production costs of about $2.20 per million BTU ($0.13/gallon) and would represent about ten percent of present U. S. demand.

Technology Policy Opportunities

The areas which show the greatest potential for cost reduction are in the areas of process demonstration, feedstock cost reduction, hot gas cleanup, and single pass methanol conversion. If all these improvements are achieved there is the potential to reduce biomass to methanol production costs more than fifty percent in relationship to the 1990 estimated cost.

An accelerated long range research plan has been developed with the objective of producing methanol from biomass resources at a cost of $0.55 per gallon ($9.17 per million BTU) or lower by the year 2000. In this plan research is proposed in the conversion area and the process components area.

The conversion research area involves design, construction, and extended operation of a demonstration gasifier system (scaled-up test bed facility) on an integrated process basis. Successful operation of this unit using a selected gasifier and small scale commercial downstream synthesis operations in

combination with success in the feedstock development program would result in achievement of the $10.25 per million BTU goal shown in the SAIC base case.

Additional research and development would be performed in the area of process components. Included in this area are research in gasifier auxiliaries, hot gas cleanup, syngas modification, and methanol synthesis. Also included in this budget is testing at large scale ancillary to the demonstration gasifier project. Success in any one of the major areas would result in further decrease in cost of production to the $0.55 per gallon target, and possibly lower.

As stated previously the present market price of methanol is $0.40 per gallon ($6.67 per million BTU), and the present estimate for methanol from biomass is about $15.83 per million BTU ($0.95/gallon). If funding is reduced or eliminated the potential reductions in costs will not be realized and methanol from biomass will not become a reality.

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14. SAIC Study

APPENDIX: Biomass Resource

Biomass resources potentially available for energy production encompass a wide range of materials, including agricultural and forest crops grown for energy feedstock purposes, agricultural and forest wastes and residues, wastes generated by food processing and forest products industries, MSW and some sewage sludge, and aquatic plants and algae. Biomass tends to occur in a very disperse manner, not in a consolidated manner such as fossil fuel deposits. The cost of collecting large quantities of biomass for a commercial energy application can be significant since the material is by nature dispersed, is often of low energy density, and is moist, if not wet. Consequently, the most attractive applications of biomass energy today generally involve biomass that has been collected for other reasons, such as forest product and food processing industry co-products and wastes, and MSW. Each must be disposed of in some manner; the alterative cost of disposal for MSW, often called the "tipping fee," may be more than $100/ton in congested urban areas if environmentally acceptable landfills or other disposal sites are not available nearby. (A small amount of sewage sludge may also be usable as a supplementary feedstock for MSW gasification plants, but the potential plant capacity to accommodate it is expected to be so small that the available material is not ordinarily included in energy resource estimates.)

One estimate of the aggregate potential biomass resources is shown in Table 1. This estimate does not include the potential resources available from dedicated plantation or farm production of either herbaceous or woody biomass crops for energy feedstocks.

Table1. Potential Energy Available from Biomass in Year 2000

(quads/year)

Resource	Estimated Recoverable	Theoretical Maximum
Wood and Wood Wastes	10.4	25.0
Municipal Solid Wastes		
Combustion	1.8	2.0
Landfill Methane	0.2	1.0
Herbaceous Biomass and Agricultural Residue	1.0	15.0
Aquatic Biomass	0.8	7.7
Industrial Solid Wastes	0.2	2.1
Sewage Methane	0.1	0.2
Manure Methane	0.05	0.9
Miscellaneous Wastes	0.05	1.0
Total	14.6	54.9

Conventional wood resources consist of wood in excess of the needs of the traditional forest products industry. These resources are available from thinning of commercial stands or from clear-cutting to allow planting of improved stands. This enormous resource if managed properly. In the United States, it is estimated that this resource currently amounts to 6.5 quads annually, not including the potential from unutilized lands that might be dedicated to future biofuels production.

Agricultural and forestry wastes represent the portion of plants and trees that remain after the more valuable portions have been separated. Primary residues include stalks, leaves, bark, and limbs left in the field after harvesting. Secondary residues are wastes produced at a processing facility, such as wood bark and scraps, black liquor and other pulping residues, bagasse, rice hulls, corn processing wastes, and feed processing wastes. Utilization of secondary wastes as a fuel at or near the source mill or processing plant has the advantage of incurring little or no additional transport costs because the wastes are a by-product (the wastes usually entail costs for disposal if they are not otherwise used). The primary residues are not only costly to collect, but at least a portion may be more valuable if left in place to decompose and maintain the quality of the soil.

MSW is the solid waste generated from households, commercial and institutional operations, and some industrial production. On the average, about 80% of the dry weight of MSW is organic materials, two-thirds of which is natural lignocellulose. The annual U.S. MSW resource is estimated to be about 2 quads currently and should expand to nearly 3 quads by 2030.

It is somewhat misleading, however, to assert that MSW is an energy resource in the traditional sense, that it is available for fuel use at the discretion of the consumer or power supplier. MSW must be disposed of. If the most economic means of disposal includes the provision of electric power, process heat, or methane as a by-product at current market values of the energy, the by-product energy will be utilized. The market price of the energy will influence the decisions regarding what type of MSW disposal plants will be built. Once plants are built, the energy product will be a permanent part of the local energy supply, irrespective of the value of the energy or the actual price paid to the MSW plant operator.

Energy crops, in comparison to fossil fuels, are a dispersed energy resource, requiring large areas of land to make large contribution of energy. The amount of energy produced per acre can range from 15 to 270 million Btu per year (equivalent to the energy contained in 0.07 to 0.13 barrels per day of petroleum produced over a year). Therefore, production of energy crops is tied to land availability. The type of land suitable for energy crops is that which is also suitable for the growing of food crops (i.e. cropland or land that has a good potential of being used as cropland). The United States has historically had a surplus of land available for the production of food crops, but not in every year. The future need for cropland for use to grow food crops is uncertain. Cropland could range anywhere from being in substantial surplus to being only adequate for food production. So a major unknown is the amount of land that could be available for energy crops. The New Farm and Forest Products Task Force (1987) stated that new farm and forest products utilizing 150 million acres need to be developed within the next 25 years.

Land availability is not a static concept. The technology of producing food crops and energy crops is and will be constantly changing. Food prices as well as energy prices are variable. Food prices and export demands are determined not only in the world market, but also by both domestic U.S. and foreign government policies as they relate to food use, production, and trade. From the farmers perspective the relevant question becomes what is the relative profitability (adjusted for risk, capital, and labor constraints) of growing energy versus food crops?

REGIONAL DISTRIBUTION

Most biomass production from energy crops will be concentrated in the Midwest/Lake States, Southeast, and the eastern Great Plains (Fig. 1). In a gross classification of land based primarily on adequate moisture and land quality, regions showing potential to grow energy crops are indicated. The boundary of the area in the Great Plains separating that which is classified as having medium potential versus a lower potential is based on where the boundary is between land that is classified as subhumid and semiarid.

The Midwest/Lake States and Southeast have large quantities of cropland and adequate rainfall. The Great Plains has more cropland than any other region, but its productivity is limited by moisture availability. Some areas are not indicated as having high or medium potential to produce energy crops, but this does not mean that no energy crops will be grown there. Two regions that may grow energy crops are the western Great Plains and the Pacific Northwest east of the Cascades, even though rainfall is limited in these areas.

Federal regions are not particularly useful geographic areas when talking about energy crop production because they aggregate some area with very different crop production characteristics (e.g. Iowa and Kansas in region 7, Louisiana and New Mexico in region 6, and North Dakota and Utah in region 8). In spite of this limitation, land potentially useful for energy crop production (i.e. land suitable for use as cropland) is listed by Federal region (Table 2). Over 85% of this land is located in Federal regions 4 to 8. At a delivered yield of 5 dry tons per acre per year, 10

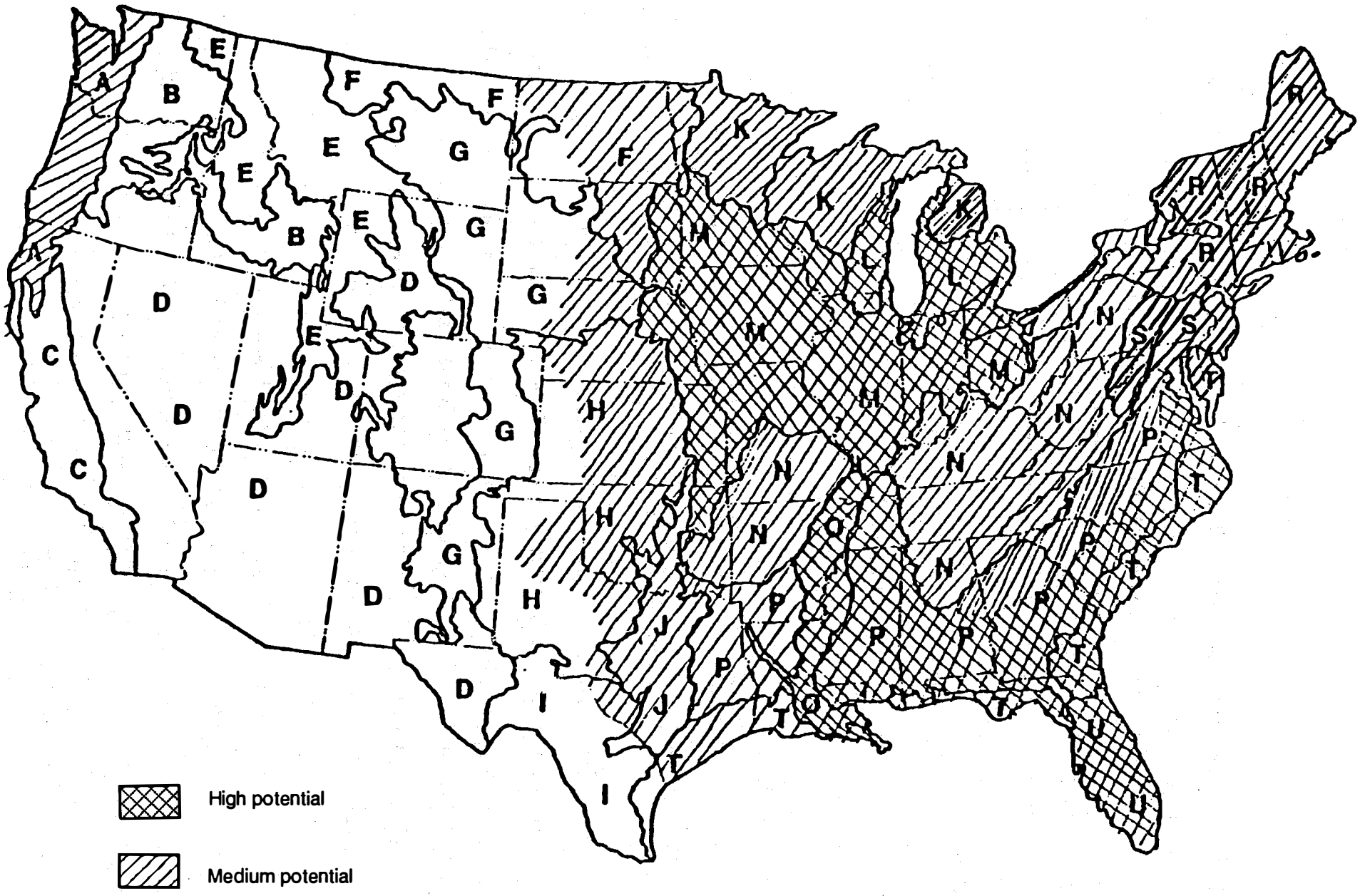

Figure 1. Potential Regional Contribution for Energy Crops

million acres would produce 0.8 quads of energy (i.e. energy contained in the raw biomass).

Table 2. Distribution of Land Potentially Useful for Energy Crops

Federal region	Land (%)	Land[a] (million acres)
1	0.7	4
2	1.6	9
3	3.6	20
4	13.5	76
5	19.5	110
6	16.9	95
7	19.9	112
8	16.9	95
9	3.0	17
10	4.2	24
United States	100.0	564

Data source is 1982 National Resources Inventory (USDA/SCS. 1987)

[a]includes land in cropland and land presently in pasture, range, forest or another use that has a high or medium potential of being used for cropland.

The potential energy crop contributions in regions 1 and 2 are limited both by available land and by crop yields. Even if 20% of the land in these regions were devoted to energy crops, at 5 dry tons per acre per year the contribution is only 0.02 quads. In region 3 land resources are also limited. In region 9 the land resources are not large, and most agriculture in this region requires irrigation. Because of the relatively low value of energy crops, irrigation is probably not a viable option. There is at present some limited acreage of short rotation woody crops (SRWC) in northern California. Region 10 can really be divided into two parts, that west of the Cascades where growing conditions are ideal for trees and east of the Cascades where moisture limits productivity. Commercial production of SRWC for energy is taking place west of the

Cascades and research indicates that yields are high. However land west of the Cascades is limited, with only about 2.8 million acres with slopes less than 8%. (Because of machinery requirements, land with slopes greater than 8% is probably unsuitable to grow SRWC). Taking 20% of land west of the Cascades with a slope of less than 8% and a yield of 12 dry tons per acre per year supplies 0.1 quads of energy.

SCALE

The cost of transportation combined with the relatively bulky (i.e. a low energy density) and diffuse nature of energy crops limits the size of a facility that can be economically supplied. A energy crop conversion facility requiring 2,000 dry tons per day of feedstock can be supplied within a 20 mile radius in most farming regions, as even at an annual energy crop yield (after accounting for losses) of 5 dry tons per acre (a yield that at present is readily achievable with many potential energy crops), less than 16% of the land would be required, while at 10 dry tons per acre only 8% of the land is required. The largest pulp and paper mills are supplied with 2,000 dry tons of wood per day.

II. COST/PERFORMANCE PROJECTIONS

A. RECENT TECHNICAL PROGRESS

SRWC. SRWC have come a long way over the past ten years. Species have been narrowed down from over 100 to 6 model species (American sycamore, black locust, eucalyptus, poplars, silver maple, and sweetgum). Initial problems of establishing stands of SRWC have largely been overcome and emphasis has shifted to improving the SRWC model species. Because of limited funding, the focus is primarily on poplars. Average annual yield

of SRWC has increased from 4 to 6 dry tons/acre from 1978 to 1987. At the same time production costs have fallen from $70 to $50/dry ton ($4.10 to $2.95/MMBtu) (Ranney et al. 1987). In the Pacific Northwest, yields are higher (as high as 19 dry tons/acre/year for the best clone) and costs are lower (presently estimated at about $2.50/MMBtu). The Pacific Northwest has nearly ideal growing conditions for SRWC, and such conditions are not found elsewhere in the United States. A major area that must be addressed, but has received only limited attention, is harvesting technology. SRWC are too large for agricultural harvesting equipment, but too small for forestry harvesting equipment.

Presently about 17,000 acres of land are planted to SRWC, primarily to supply pulp and paper, but some is also planted specifically as an energy crop to be used for direct combustion. The forest products industry has begun to take notice of SRWC as a source of wood, for both wood products as well as energy.

The forest products industry is favorably disposed toward SRWC. However farmers control most of the land on which SRWC will be grown. Because of its perennial nature and the difficulty of substituting another crop for SRWC (it is not as easy to clear a field of trees as it is to clear a field herbaceous crops), farmers may be somewhat reluctant to grow SRWC, unless they can be assured of markets which provide adequate returns. Farmers are used to getting a cash flow from most of their activities within a year, while with SRWC the return is not likely to be before 5 years.

Herbaceous energy crops. Herbaceous energy crops (HEC) are presently used for forage. Only corn for ethanol and some crop residues for direct

combustion are presently used for energy. The Gas Research Institute (GRI) has funded research on sorghum in Texas in cooperation with Texas A&M University, and primarily on napiergrass, energy cane, and water hyacinth in Florida in cooperation with the University of Florida. In these environments they have done relatively well and technical advances have been made. Research in the Herbaceous Energy Crops Program (HECP) covers a much broader geographic range than what these projects cover. In 1985 the HECP began screening over 25 HEC in the Southeast and Midwest/Lake States and began additional screening in the Great Plains in 1988. Species are now being selected for further development as energy crops, and include switchgrass, reed canarygrass, sorghum, and sericea lespedeza. Depending upon funding additional species, such as energy cane and flatpea, may be considered for development. Production costs for herbaceous crops are presently estimated to be in the range of $45 to $60/dry ton ($3.00 to $4.00/MMBtu), assuming 6 months of storage (with no storage costs are lower). Limited research in the HECP-sponsored research shows that a considerable increase in yield (and thus reduction in cost) can be achieved in many cases by selecting the appropriate variety within a species. From only one year of data from a project at Auburn, with the best variety of switchgrass had a yield of 7.8 compared to 3.9 dry tons/acre for the standard variety. From a sorghum variety trial at Purdue, the best varieties had yields in excess of 14 dry tons/acre. However, most of the species, with the exception of sorghum, have had limited breeding.

There is at present no HEC industry, however because HEC are so similar to present agricultural crops, their acceptance by agriculture should not be a problem, as long as HEC are profitable and markets are

assured. With regard to profitability, farmers decide among crops by the relative returns available to growing the crop, none of which in fact may be profitable or may be profitable only because of government farm programs.

B. DESCRIPTION OF FIGURES OF MERIT

Crop yield. The primary figure of merit for energy crop production is yield. Yield is expressed in terms of dry tons/acre/year of standing biomass. To determine what is actually delivered to a conversion facility, losses for harvest and storage must be taken into account. Crop yield will be different for SRWC and HEC, and there are also differences between perennial and annual HEC. There are also regional differences in yield.

SRWC harvest/handling/transport cost. This cost is expressed in terms of $/dry ton of material handled. Harvest/handling/transport costs account for between 1/3 and 1/2 of SRWC costs.

C. BEST STORY OF WHY COST/PERFORMANCE GOALS CAN BE MET

There are 5 basic energy crop production systems: SRWC-coppiced, SRWC-not coppiced, HEC-perennial and thin stemmed, HEC-perennial and thick stemmed, and HEC-annual and thick stemmed (Table 3). This is not an exhaustive listing (e.g. excludes HEC-annual and thin stemmed), but lists the most important systems and the ones expected to make the greatest contributions of energy feedstocks. There is expected to be some mixture of these systems in each region, although some regions may use only SRWC (e.g. northern Lake States) and others may use only HEC (e.g. Great Plains). There are major cost advantages to harvesting energy crops and almost immediately using them. Immediate use avoids storage losses as well

Table 3. Biomass Crop Production Systems

crop type[1]	growth habit	other information	inputs[2]	yield	storage method	harvest window	regions[3]
SRWC	perennial	coppice	low	moderate/high[4]	chunks or chips	2/3 winter, 1/3 all year[5]	PNW, MW/L, SE, NE
SRWC	perennial	no coppice	low	moderate/high	chunks or chips	all year	PNW, MW/L, SE, NE
HEC	perennial	thin-stemmed	low	moderate	hay, large round bales no storage	late spring to fall[6]	MW/L, SE, PL, NE MW/L, SE, PL, NE
HEC	perennial	thick-stemmed	moderate	high	silage no storage[7]	mid summer to early fall	SE SE
HEC	annual	thick-stemmed	moderate	high	silage no storage	mid summer to early fall	MW/L MW/L

[1] SRWC = short rotation woody crops, HEC = herbaceous energy crops

[2] inputs relative to conventional agriculture

[3] PNW = Pacific Northwest west of Cascades
MW/L = Midwest/Lake States
SE = Southeast
NE = Northeast
PL = Plains
any system possible in Hawaii

[4] high yields in PNW

[5] assumes two coppice growth cycles, first two growth cycles must be harvested in winter to ensure coppicing, last coppice growth can be harvested at any time

[6] cool-season species harvested in late spring and fall, warm-season species harvested in mid summer to fall

[7] all biomass crop systems can use the no storage option and will, to the extent possible, but the greatest advantage in cost savings is for the thick-stemmed HEC, either perennial or annual

as storage costs. Because of the seasonality of energy crop production some mixture of immediate use and storage is likely to be used.

The cost estimates submitted for the NES were supplied in 1987 dollars. In this material 1990 dollars will be used. Thus $2.00/MMBtu in 1987 dollars is about $2.25/MMBtu in 1990 dollars.

A discount rate of 10% is used. Fertilizer prices are assumed to remain constant in real dollars.

SRWC costs. For SRWC the example presented is for that of a coppice (i.e. the trees regrow from their stumps after harvest) situation. At the time of harvest of SRWC a decision must be made as to whether to allow the trees to coppice, or to replace the current stand with a newly planted stand that would utilize genetically-improved material. Presumably planting a new stand would occur only if the costs of producing SRWC was expected to be less with the genetically-improved material than with the established stand. Therefore only the scenario for the coppice situation will be described.

For a coppice strategy, a 6-year harvest interval with three harvests (thus stand life is 18 years) is assumed (the initial harvest and two harvests of coppice) and yield is assumed to be equal for each harvest, at an annualized rate of 9 dry tons/acre. The site is assumed to be either cropland or pasture or range, and thus does not need to be cleared, but its basically in a state that it can be prepared by conventional farm equipment. The road infrastructure is assumed to be in place. Planting density is 850 trees/acre and each cutting costs $0.10. Fertilization rates are fairly modest by agricultural standards, at annualized rates of 45, 11, and 11 lb/ac for N, P_2O_5, and K_2O, respectively. Weed control is

assumed to be needed in years 1 and 2, but not in years 3 through 6. Disease and pest control is utilized as needed and averages $5.00/acre/year. Land is assumed to cost $40/acre, which is low by Midwest standards, but on the high side in many areas of the Southeast. Losses are assumed to be 15% of standing biomass, with half of the losses attributed to harvest and half to storage. Transportation is assumed to be 25 miles one way. Harvest/handling/transportation cost can be reduced to $15/dry ton from the present estimated cost of $18/dry ton. Under this set of assumptions the delivered cost of wood is $38/dry ton ($2.25/MMBtu).

The keys to achieving the $2.25/MMBtu cost of wood from SRWC are: a yield of 9 dry tons/acre/year, effective weed control, trees requiring only limited pest and disease control, and reducing harvesting costs to $15/dry ton. Yields from poplars at Rhinelander, WI have not been especially impressive at 4 dry tons/acre/year, but 3 years of data from test plots in Minnesota indicate much higher yields and if extrapolated for the better clones, appear to be on target to average close to 9 dry tons/acre/year. The land in Minnesota is much better than that found at Rhinelander. In the Pacific Northwest unimproved poplars averaged 5 dry tons/acre/year, while the average of improved material (hybrids) averaged 14 and the best averaged 19 dry tons/acre/year (Wright et al. 1989). This type of yield would not be expected in the Midwest, but the almost quadrupling of yields indicates that there is great potential for genetic gains and why it is felt that 9 dry tons/acre/year is an achievable yield. Disease and pest control are often bred for in improved trees, and these traits will simply require time to achieve. Weed control is primarily developing optimal strategies for controlling weeds using a mix of mechanical, chemical, and

nursery crop options and also ensuring rapid juvenile growth such that canopy closure occurs during the second year. Harvesting costs can be reduced if optimal-sized equipment can be developed, and is primarily mechanical in nature and requires a systems approach to developing optimal harvesting equipment.

HEC crops. For HEC, costs for two systems will be discussed, both for thin-stemmed perennials, one being cut and then almost immediately utilized, thus avoiding baling and storage losses, and the other baling hay and storing it for later use. Switchgrass will be used as the example grass. As is the case with SRWC, agricultural-type land is assumed to be used and the road infrastructure is assumed to be in place. The costs cited are for the Midwest, but yields and costs in the Southeast would be quite similar (lower land costs, but higher pest control costs).

For switchgrass it is assumed that 1 year is required to establish the stand and good quality seed is used. The stand has a very long lifetime when harvested only once or twice a year and with only modest nitrogen applications. Fertilizer requirements are assumed to be 45, 60, and 100 lb/acre of N, P_2O_5, and K_2O, respectively. Other than fertilizer application, the only other machinery need is for harvest, baling (if required), and transportation. Traditional farm equipment can be used. Diesel fuel is assumed to be priced at $1.35/gallon. Land cost is assumed to be $50/acre. Machinery productivity is assumed to improve by 20% over the present. With a standing yield of 9 dry tons/acre/year, the cost of switchgrass is $40/dry ton ($2.70/MMBtu) if harvested and baled as hay and stored for 6 months (assumed harvest loss is 19% and assumed storage loss is 15%), but only $32/dry ton ($2.15/MMBtu) if cut and utilized almost

immediately (assumed loss of 5%). If no N is required and transportation distance is only 12.5 miles instead of 25 miles, then costs are reduced to $37/dry ton ($2.50/MMBtu) and $29/dry ton ($1.95/MMBtu) for the storage and immediate use options, respectively. To operate a conversion facility year round and to achieve a goal of $2.25/MMBtu, some combination of these two options would be needed.

The keys to achieving a goal of $2.25/MMBtu is to obtain a yield of 9 dry tons/acre/year and to improve machinery productivity by 20%. With only a modest amount of selection at Auburn and using what is considered to be a good cultivar for the Midwest, research plot yields of 7 to 8 dry tons/acre on marginal cropland sites have been seen, giving some indication of the potential yield of switchgrass. With additional selection and breeding research a yield of 9 dry tons/acre/year seems achievable. We want to achieve this yield in both good and poor growing seasons and across a wide range of sites. Only a limited amount of selection research has been done on switchgrass. To increase the productivity of machinery 20% over 15 to 20 years also seems to be a reasonable goal, requiring a rate of productivity increase of 1%/year. It is also possible to reduce harvest and storage losses for the baled and stored hay.

Overall strategy. Using a combination of SRWC and HEC can reduce the need for storage and can also be adapted to more site conditions near a conversion facility. SRWC can provide fresh feedstock supplies, while HEC are dormant during the winter.

In addition to the cost and productivity goals mentioned, the quality of the biomass feedstock can be improved to allow for greater and easier utilization of feedstocks by various conversion processes. For HEC more

than SRWC, the opportunity to improve feedstock quality exists through selection, breeding, and genetic modification (e.g. control of lignin synthesis pathway) of plants. Lignin has a higher energy content than carbohydrates and is thus desirable for thermal processes, but is an impediment to biological conversion processes. For biological processes a high carbohydrate content is desirable.

III. DESCRIPTION OF BASE CONDITIONS, RELATIONSHIPS AND OPPORTUNITIES

A. ASSUMED R&D FUNDING LEVELS IN SAIC BASE CASE

A funding level of $10 million/year is assumed for the costs, yields, and quantities of energy crops that have been previously stated. Whether this funding comes from the public or private sector is immaterial, except to the extent that private sector money may inhibit the transfer of research information to other researchers. This level of funding focuses research on the 3 most important regions, the Midwest/Lake States, the Southeast, and the Great Plains.

Funding at this level will allow genetic improvements to a selected number of species and some physiological research on these selected species that will have long-run benefits to their genetic improvement programs, develop improved harvest, storage, and handling equipment, allow technology dissemination and scale-up trials, and assessments of resource, environmental, and economic issues related to energy crops to be addressed. Plant improvement is a long-term effort that requires a sustained effort, but improvement of commercial agricultural species show the benefits of such efforts. These improvements to energy crops will result in higher yields, lower costs, and better feedstock quality, and come from better

stress tolerance (e.g. water stress) and site adaptability, better nutrient utilization, and better pest resistance, as well as better allocation of photosynthate to the desired parts of the plant and chemical components. Because site conditions vary greatly within as well as between regions, a portfolio of energy crops, both HEC and SRWC are needed to provide large quantities of biomass at minimum prices. Again, equipment development is an activity that is necessary and requires a sustained effort. Over time research efforts have brought great benefits to agricultural technology for food and forage crops and the energy crop research programs have shown progress over their limited lifetimes. At $2.25/MMBtu the lower limit of the cost of producing large quantities of energy crops is being pushed. Costs may only be reduced to $2.50/MMBtu, but within the range of $2.25 to $2.50/MMBtu we are confident that with adequate research efforts the technology can be developed to produce large quantities of energy crops.

B. IMPLICIT PRODUCTION LEVELS

High levels of energy crop production can be supported by the land base in the United States if the appropriate crop production technologies are developed. One quad of energy (contained in the raw biomass) require between 7 million acres at a yield of 9 dry tons/acre. Therefore it is imperative that an appropriate portfolio of energy crops be developed to allow for the technology to be available to produce multiple quads of energy, such as is indicated in Table B-4 of The Potential of Renewable Energy: An Interlaboratory White Paper (INEL et al. 1990). Agricultural input industries (e.g. machinery, fertilizer) will respond to demands placed on them by energy crops for needed inputs.

As the quantity of energy crops demanded increases, land becomes a relatively scarcer resource and land costs can be expected to increase. The exact relationship between energy crop demand and cost has not been studied. A project to address this issue will be started in late 1990 or early 1991, but will require 2 years for completion. If energy crops are priced attractively to farmers they will respond and produce. Historically, higher crop prices have led to higher levels of crops production and prices do not have to increase greatly to get a supply response.

C. TECHNOLOGY POLICY OPPORTUNITIES

The best opportunities to "accelerate the cost curve" (which is taken to mean shift the cost curve down so that higher quantities of energy crops can be produced at the same cost) is to increase the number of species being developed as energy crops, to increase the geographical coverage to the more marginal regions, and to increase the research on genetics and the more basic physiology. The first of these allows the development of energy crop production technology suitable to a greater fraction of land within a region. It also allows for fresh supplies of energy crops to be available over a longer period of the year and thus can reduce the need for storage which in turn can reduce costs. The second of these allows a higher level of energy crop production by expanding the land base. The third of these should give insight into how to modify plants so that they have better stress resistance (e.g. water stress) and pest and disease resistance and how the mechanisms work for allocating photosynthate among plant parts (e.g. roots, stems, leaves) and among chemical components (e.g. cellulose, lignin). Increasing stress and pest and disease resistance reduces yield

variation and reduces risks. Understanding and control of these mechanisms can have great payoffs, but requires patience and a sustained research effort.

If funding levels are decreased the number of species developed as energy crops will decrease and the geographical coverage will decrease. The more basic type research such as the physiology will be limited and there may be insufficient funding for equipment development and scale-up efforts. Research will probably be limited to selection and breeding on a limited number of species, but will delay commercialization of energy crops.

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Section 10

TECHNOLOGY EVOLUTION RATIONALE FOR SOLAR BUILDINGS TECHNOLOGY

October 5, 1990

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RATIONALE FOR SOLAR BUILDINGS TECHNOLOGY

PREFACE

This paper supports solar buildings cost and performance projections for the National Energy Strategy. It reviews the basic principles of solar buildings technologies, discusses the market status of the technologies, and identifies user requirements to help establish the future technology path for the development of economically competitive technologies. It projects trends in the cost and performance of the technologies based on input from government laboratories and industry experts. There are two scenarios used for the projections: a base case where current trends in technology development and the industry continue in a business-as-usual sense, and an accelerated R&D case where the pace and scope of the federal program is modestly increased. This enables technologies to be introduced to the marketplace more quickly.

It should be noted that the information provided is limited to the individual technologies identified and is consistent with the budget scenarios outlined. Other technologies such as passive cooling for residential and nonresidential buildings and core daylighting using optical devices also have potential contribution to meeting building energy needs. In addition, overall building level improvements due to integrated systems -- combined heating, cooling, and daylighting technologies -- have not been included. Additional analysis required to adequately characterize these technologies are planned.

1.0 INTRODUCTION

Solar technologies for water heating, space conditioning, and lighting represent promising energy supply alternatives for residential and nonresidential buildings. These technologies can efficiently convert sunlight into thermal energy to closely match the temperature requirements of a variety of end-uses, and they can be used directly for daylighting -- reducing electricity requirements for lighting, while improving occupant comfort and productivity. While the technical feasibility of a broad array of solar buildings technologies has been clearly demonstrated -- from simple solar water heaters for residences to large solar cooling systems for commercial buildings -- a significant challenge remains in achieving economic competitiveness and realizing the technologies' potential to meet a large share of building energy requirements.

1.1 Technology Description

Solar buildings technologies utilize the radiant energy of sunlight and the thermal energy it produces in domestic pool heating, water heating, space conditioning, and daylighting. They also make use of the environment to promote heat flows to the atmosphere, to divert thermal radiation away from the building, and take advantage of earth contact benefits to provide a cooling effect. Solar buildings technologies include active and passive heating and cooling systems, as well as daylighting systems.

Solar water and space heating systems are characterized by: (1) a collection system that captures and converts the sun's energy into usable heat, (2) a distribution system that delivers the collected heat to the required location, (3) a storage system to store the heat for later use, and (4) a control system to regulate the collection, distribution, and storage of heat. Traditionally, systems that use pumps or fans for heat distribution and solar collectors distinct from the building structure have been labeled as active systems. Passive systems typically use the building structure directly for collection (e.g., windows) and storage (e.g., walls, floors) and rely on natural convection and radiation for heat distribution.

Active Water Heating systems for residences typically consist of two to four flat plate or evacuated tube solar collectors (40-80 square feet in total area), a storage unit (40-120 gallon capacity), a pump, and controls. Passive solar water heaters generally fall into two categories: 1) Thermosiphon systems which use natural convection for heat distribution to the water storage tank and are typically limited to regions that do not experience freezing temperatures and 2) Integral collector storage (ICS) systems which combine the passive collector and storage as one unit.

Active Space Heating Systems of both air and liquid design operate in much the same way as solar water heating systems, but have larger collector array areas and storage units and more complex control systems. In contrast to hot water systems, active space heating systems require more sophisticated design, installation, and maintenance techniques.

In a typical **Passive Solar Heating System**, solar radiation entering through windows (apertures) is converted to thermal energy upon absorption by building interior surfaces (direct systems). The amount of useful solar energy collected depends strongly on the type of window glazing used and the type, amount, and placement of storage material relative to the aperture. Passive designs also include sunspaces, wherein the heat collection can be effectively isolated from the building structure, and indirect systems where the thermal storage is placed directly behind the aperture (also called mass wall or Trombe wall systems). Proper shading in the form of overhangs or shading devices, must be incorporated in the design to prevent overheating during the summer months. Window insulating devices are sometimes used to prevent nighttime heat loss during the winter months.

Active Solar Cooling can provide for year-round utilization of collected solar heat and thereby significantly increase the cost effectiveness and energy contribution of solar installations. Currently, solar desiccant and solar driven absorption systems are the active cooling technology options that appear to have the greatest potential. Solar desiccant systems use a desiccant or drying agent to absorb water vapor in recirculated or ventilation air to reduce humidity levels. The warm dry air is subsequently cooled evaporatively to the required temperature. The solar heat from the collectors is used to dry or regenerate the desiccant so it can regain its moisture trapping or sorption capacity.

A solar absorption system uses the thermal energy from the solar collector to separate a binary mixture of an absorbent and a refrigerant fluid. The refrigerant is condensed, throttled and evaporated to yield a cooling effect, after which it is reabsorbed to continue the cycle.

Passive Cooling Systems which rely primarily on natural ventilation and evaporation to provide a cooling effect, are used in residential buildings in some portions of the U.S. Ventilation strategies include proper placement of windows and vents to maximize wind capture, designs that induce air circulation using the chimney or stack effect, and designs that use cool night air to precool building storage elements. Vented mass walls, operable clerestory windows, and vented storage elements (e.g., hollow concrete block floors), have been found to be effective for these applications. Both natural and forced ventilation are used in the residential sector to promote occupancy comfort, and have high potential in the nonresidential sector. Evaporative cooling strategies include the use of roof spray systems to reduce roof surface temperatures, thereby indirectly reducing building air temperatures, and evaporative coolers. Radiative cooling that takes advantage of temperature differences between the building surface and the night sky also repressent another promising option. Dehumidification strategies in conjunction with passive cooling strategies also show potential.

Daylighting technologies are categorized as either perimeter or core systems depending on whether natural illumination is provided to the spaces directly adjacent to the building exterior or to interior spaces, respectively. Since solar radiation is both a source of heat and light, daylighting use has implications for heating and cooling loads as well as electrical lighting requirements. The selective control of the quantity and quality of light transmitted

is central to all the daylighting technologies. Among the more common approaches for perimeter daylighting are light shelves, roof monitors, and sidelighting. Atria represent the predominant type of core daylighting system currently in use. They generally are constructed of standard glazing materials and are designed for aesthetics rather than for maximum energy contributions. Other options include optical systems that can collect sunlight and direct it into the buildings interior.

It should be noted that combining individual solar buildings technologies as integrated systems within a building can result in significantly greater energy contributions and more favorable economics than individual technologies. For example, storage associated with passive heating systems can, with proper design, also be used for "cool storage" (e.g., in conjunction with ventilative cooling) at little additional cost. Similar considerations hold for other integrated solar heating, cooling, and daylighting systems.

1.2 Technology Applications/Users

The primary applications for solar buildings technologies are pool heating, domestic and service water heating, space heating, cooling, and daylighting. The principal market for all but daylighting technologies is the residential buildings sector. In the near-term, the market is likely to remain residential -- primarily for solar pool heaters, solar water heaters, and passive solar homes in regions with moderate to high insolation and high electricity rates (e.g., California). Some expansion in the commercial sector is anticipated, led by daylighting technologies. This will be spurred in part by the growth in electricity demand, and the utility search for technologies that can help defer plant additions. This should also increase the demand for solar cooling technologies. In addition, advanced electrochromic glazings may be introduced in automotive markets prior to their entry in the buildings market in the late 1990s.

1.3 Resource Availability

The solar energy resource varies widely across the United States from less than 400,000 Btu's/sq. ft. to over 700,000 Btu's/sq. ft. on an annual basis on a tilted surface. The total accessible U.S. solar resource is 101 trillion barrels of oil equivalent energy annually. Current solar buildings technologies make limited use of this resource, typically converting less than 1/2 of the incident radiation to useful thermal energy. Even in cold, cloudy climates such as Buffalo, New York or Bismarck, North Dakota, enough solar energy falls on the roof of a typical single family residence to supply more than 80% of its heating requirements. In terms of seasonal energy requirements, the potential appears even more striking. Solar radiation incident on a residential building's entire envelope (walls and roof) during the heating season exceeds the heating energy requirements for the building by factors of four to five in the coldest regions of the country and by factors of ten or greater in more than half of the U.S. Similar potential for energy contributions applies to solar cooling. Solar heat may be used to drive cooling equipment to mechanically reject building heat. Natural environmental resources may also be used to remove heat via ventilation, evaporation or radiation processes. For example, the resource for night ventilation coupled

with thermal storage could provide more than 80% of the cooling requirements for half the nation's residences and at least 40% for the remainder of the U.S. The resource for daylighting is nearly 20 times the typical lighting requirements for a small commercial/institutional building.

1.4 Industry Status

The solar buildings industry is a diverse group that consists of solar equipment manufacturers engaged primarily in the sale of solar collectors and active solar water and space heating systems, building materials suppliers involved in the production and distribution of glass and masonry products used in passive solar designs, architects and engineers engaged in the design of solar buildings, homebuilders, developers, and mechanical contractors. In addition, trade organizations such as the Solar Energy Industries Association and the Passive Solar Industries Council, and professional organizations such as the American Society of Heating, Refrigerating, and Air Conditioning Engineers, and the American Institute of Architects have major roles in advancing technologies within the mainstream of the building construction practice.

A small group of manufacturers forms the core of the solar industry for active solar technologies, while residential homebuilders and designers are the predominant force with respect to passive solar technologies. These are primarily small businesses, with relatively small R&D budgets. However, major glass and window manufacturers are expected to increase their development efforts in the area of advanced glazings.

Prior to the expiration of the federal residential solar energy tax credits in 1985, the solar market was strong and stable with sales of active solar water and space heating systems alone estimated to be between $700 million and $1 billion annually. Between 1984 and 1988 annual solar collector production dropped from 15.4 million square feet to 4.1 million square feet, and sales fell to an estimated $100 to $300 million. Most of this drop was attributable to the decline in residential active solar water heating system sales which fell nearly 90% during this period. Solar pool heater sales now predominate, accounting for 76% of total collector production and once again regaining the dominant position they held until 1982. The number of solar collector manufacturers dropped from more than 200 in 1984 to less than 50 in 1988. Overall employment in companies manufacturing, selling, and installing active solar systems has also dropped substantially. On the other hand, passive solar technologies continue to make progress in the residential building market. For example, sales of low emittance (low-e) windows, which are frequently used for both new and retrofit construction, continue to increase. They account for a substantial share of the new residential building market. For example, Anderson Windows will soon offer only low-e glazing in their windows. Additionally sunspaces continue to gain in popularity, although more frequently for their amenity value, rather than potential energy benefits.

U.S. collector and solar hot water system manufacturers face competition in domestic and international markets from several manufacturers based overseas. Australia and Israel have been successfully marketing thermosiphon systems in the U.S. and worldwide through

subsidiaries. Japan has also begun to establish an export market for its solar heating and cooling products. Evacuated tube collector technology, primarily for space heating applications, is exported by European, Japanese, and Canadian firms. Sweden is now leading in the development and application of large scale solar heating systems using seasonal storage. Since 1982, imports of solar collectors to the U.S. have exceeded exports by more than 50%. In addition, the steep decline in U.S. production and sales has boosted imports from 4% of total U.S. solar collector sales in 1984 to 17% in 1988 (primarily for pool heating and to a lesser extent water heating). Additionally, the Japanese and Europeans are attempting to increase their share of the world's high-performance glazing markets. High-performance glazings, such as low-e and electrochromic glazings, are expected to assume increased significance in future developments of passive solar systems. Foreign builders of manufactured homes (sometimes incorporating passive solar and high efficiency features) are expected to increase activity in the U.S., primarily through the establishment of U.S.-based plants.

1.5 Market Acceptance and Experience

It is estimated that in the United States today, as many as one million active solar water heating systems have been installed. More than twice as many systems may be in place in other countries of the International Energy Agency. Most of the U.S. systems were installed in the late 1970s and early 1980s, as a result of the combination of rising energy prices and government tax credits. Although many of these systems suffered from hasty designs and poor installation, as well as unreliable controllers and sensors, the reliability of today's systems has improved considerably. However, lower energy prices and the expiration of the federal solar energy tax credits have reduced the rate of new installations dramatically in the United States. Operating experience with a small number of active solar cooling systems has also been obtained, but very little market penetration has occurred.

Although it is difficult to determine the number of houses using passive solar technology today and the amount of energy saved nationwide each year, it has been estimated that 300,000 homes in the United States include some passive solar design features. The costs of passive solar heating and cooling are also somewhat more difficult to estimate than those of active solar technologies. Many passive materials and techniques can be incorporated into building construction at little additional cost. The cost of energy saved from passive solar construction is comparable to that for energy-conserving buildings in general. Daylighting technologies are gaining in acceptance with generally good operational results. A number of utilities have shown interest in daylighting as a means of reducing electric lighting demand. However, much of this has been limited to subsidizing the cost of daylighting sensors/controls.

2.0 TECHNICAL STATUS

2.1 Figures of Merit

The solar buildings technology section of the Renewable Energy Technology Characterization presents several figures of merit to characterize the projected progress of solar buildings technologies. One useful figure of merit is the levelized cost of energy, or COE, in units of dollars per million Btu. This is defined as the annualized cost of owning and operating the system divided by the annual energy delivered by the system for the particular building end-use(s). Since COE estimates combine initial cost, annual O&M costs, and replacement costs, the resulting value is too complex to use as the basis for a descriptive rationale. Consequently, additional figures of merit are used to define technology status including:

- Annual Energy Delivered Per Unit Collector or Aperture Area (Btu/sq. ft.) -This is a term commonly used to normalize the thermal output of the system per square foot of solar collector or aperture area. In the buildings technology characterization, the thermal energy is the total energy delivered and accounts for all thermal losses to the point of delivery.

- Total System Cost per Unit Collector or Aperture Area ($/sq. ft.) -- This is a term commonly used to normalize the total cost of the system per square foot of solar collector array or aperature area. Again, this is used in the solar building technology characterization to include all system capital costs. Gnerally, these are provided as incremental costs -- the costs of the system over and above what a conventional system would cost for the same end-use.

- Annual Energy Delivered (MMBtu/yr) -- This is the amount of thermal energy delivered by the solar system per year that is used to meet the building's load. For passive heating systems, this is the net thermal energy provided, and accounts for losses as well as gains due to larger than conventional aperture areas.

- Solar Fraction (%) -- The solar fraction is a term used to describe the percentage of the load met by the solar system. It is defined as the solar energy delivered for the application or end-use divided by the load for that application or end-use.

- System Efficiency (%) -- The system efficiency of the solar system is defined as the energy supplied by the solar system to the load divided by the total solar energy incident upon the collection surface (collectors, glazings surfaces, etc.), expressed as a percentage.

- Operation and Maintenance (O&M) -- Annual O&M accounts for all the costs incurred for regular, scheduled operation and maintenance of the system including parts and labor. This is usually reported in dollars ($).

- Parasitic Energy (kWh/yr) -- This term refers to the energy required to operate pumps and fans to transfer thermal energy from the point of collection to the point of use.

2.2 Historical Technology Trends/Current Status

Typical residential **active solar water heating** systems are available at installed costs that range from $2,000 - $5,000, and offer potential savings from 40% to 70% in annual hot water expenses. Flat plate solar collectors range in cost from $10-20/sq. ft. and represent 20-40% of the installed system cost. The efficiency of flat plate collectors used in these systems has increased by 35%, and the incidence of premature system problems has decreased markedly from the days of early federal demonstration programs. Current trends are toward reduced cost through system standardization and mass production. Research results indicate that performance improvements for conventional technologies are also possible, such as a 15% gain in performance with reduced collector loop flow rates.

Typical residential **active solar space heating** system costs are between $8,000 and $10,000, although smaller systems that do not incorporate storage are available at lower costs. Typical savings are from 30% to 70% of annual heating expenses. The performance and reliability of these systems has improved substantially over the past decade as a result of improved components and design and installation practices. However, significant cost, performance, and reliability improvements are required to meet the performance/cost ratios of conventional space heating systems. Advances such as large area collectors, new materials for low cost collectors, plastic storage tanks, and distribution systems, and effective systems integration within the building (multifunction applications), will enable such improvements to be realized.

Passive heating systems have proven to be successful in contributing solar energy for heating single-family homes and small nonresidential buildings. The measured performance of 48 new, single family detached passive homes indicated passive features provided an average of 39% of heating energy requirements. The monitored performance of small nonresidential passive buildings tracked by the DOE research program exhibited savings in heating, lighting, and cooling energy use of 46% compared to conventional buildings of equal size. The cost of these nonresidential buildings was comparable to energy conserving buildings; however, the systems required greater occupant attention to control than conventional buildings.

Simplified passive solar heating design and analysis tools have been developed for single-family and small nonresidential applications. However, more complex simulation codes must be used to analyze multizone/multistory structures. This has tended to limit consideration of passive features by mainstream architects. Improved performance and automatic operation could be achieved with advanced windows that reduce heat losses, and advanced thermal storage and transport systems that provide greater flexibility, control, and capacity for thermal energy storage and distribution. Recent developments such as low heat loss, low-emissivity glazings, have already demonstrated the promise of these advances in

improving the cost effectiveness of passive solar heating systems, and extending their range of applicability.

Experimental **active solar cooling** systems have demonstrated the capability to meet 40% or more of a building's cooling requirements. However, an increase in their performance to cost ratio by a factor of three is required before these systems can be economically competitive with conventional electrically driven air conditioning systems in most applications. This will require improvements in system performance, including reductions in auxiliary energy requirements, and reductions in system costs. Costs of solar collection systems for cooling are comparable to heating systems but annual system efficiency is improved due to the year round load profile. The additional costs of cooling systems are primarily in the thermally driven chillers and dehumidifiers. The costs of the most recently marketed residential solar cooling system ranged from $4,000-$8,000/ton cooling; or from $12,000-$24,000 for a typical system.

Daylighting technologies for naturally illuminating perimeter offices and interiors of single story buildings (or the top story of buildings) are currently available, although design information remains limited and adequate design tools are still lacking. Roof aperture systems typified by skylights and roof monitors have proven effective in providing adequate illumination levels and reducing cooling loads imposed by artificial lighting systems. Improved daylighting systems are needed that can overcome the problem of fluctuations in solar availability. New glazing materials with optical switching capabilities (electrochromic devises), that can dynamically control the transmission of heat and light in response to interior conditions, could significantly increase daylighting contributions to buildings. Electrochromic devices operate as automated shutters to modulate heat gain and daylight transmittance through windows. Their optical properties change in response to a brief, externally applied current. The chemical reaction resulting from the current flow causes either transparency or coloration, depending on the direction of the current. Typical electrochromic devices have a total thickness that is less than the thickness of a single sheet of paper.

With the exception of atria, very few core daylighting systems are in current use. Atria designs have gained in popularity as a result of their amenity value, as well as energy savings potential. New designs incorporating advanced glazing materials will substantially improve their overall effectiveness in reducing electricity use for lighting and cooling. But, little information exists on the energy impacts of current atria designs, or on methods to integrate light collection, transport, and distribution systems with conventional lighting and HVAC systems. New technologies which can collect, transport, and distribute light to the core areas of buildings offer promise of more flexible alternatives for daylighting. Holographic diffractive structures (HDS) are another potentially promising technology for use of daylight in interior spaces. These systems project light at a fixed angle into a building's interior, regardless of the daily or seasonal variations in the direction of incoming sunlight.

The federal program has been instrumental in a number of these developments and has provided a broad range of information on system design, manufacture, installation, and

operation. Much of this information was used to develop improved component and system designs, design guides, testing and performance standards, and performance estimation models. This aided manufacturers in developing improved products. Specific contributions include:

- High performance collectors -- Compound parabolic concentrator (CPC) evacuated tube collectors were developed that established new performance records for nontracking collectors. The CPC's technology was incorporated in several commercial products. In addition, research on selective absorber coatings yielded new insights into the operation and durability of these coatings in collector applications. Selective coatings increase solar collector efficiencies and are now commonly used in high performance collectors of all types.

- Low-emissivity (Low-e) glazings -- The program was a key contributor to the successful development of this technology. Low-e glazings have significantly higher thermal resistance characteristics than conventional single or double-pane windows, with only a slight decrease in solar energy transmittance, thereby reducing heat losses in winter. They are now widely used throughout the construction industry for energy conserving designs as well as in passive solar applications.

- Design Information -- Several design tools have been developed under the auspices of the program including the solar load ratio (SLR) method for passive solar buildings and the F-Chart method for active solar systems. Both of these performance prediction methods have become widely used in the design process and have been incorporated in commercially available software. In addition, design manuals and software cosponsored by the program and the buildings industry have been developed. These provide a much more comprehensive source of information than was previously available, and address important regional considerations in design selection.

- Testing, Rating, and Certification Methods -- The program was instrumental in the establishment of more than 20 standardized test and rating methodologies for active systems through its work with professional societies. These included methods to test solar water heating systems, solar collectors, thermal storage units, and materials used in various components (e.g., glazings, insulation, and storage tank materials). These have helped to eliminate some of the uncertainty in equipment performance and have paved the way for cooperative efforts among states regarding equipment certification requirements.

3.0 COST AND PERFORMANCE PROJECTIONS

In this section, two funding scenarios are evaluated in terms of their impacts on achieving the technology improvements required for significant market penetration of various solar buildings technologies. The technologies evaluated are considered representiative, but do not provide complete coverage. For example, passive cooling technologies and core daylighting technologies while promising, are not included. Efforts are underway to develop complete technical, cost, and economic information for these systems. The base case scenario assumes that annual funding levels for the federal R&D program will remain at the FY 1990 level of approximately $4.0 million per year. The accelerated funding scenarios assumes a doubling or tripling of the FY 1990 figure.

The long-term objective of solar buildings research activities is to develop technologies that have direct application to the general buildings market. Markets where long-term, low-cost financing is accessible, and areas where higher energy costs coincide with high resource availability, are providing initial markets for the solar industry. Economic competitiveness is, in most cases, the primary hurdle. Initial cost is frequently the buyer's primary decision criterion. Hence, even if energy efficient systems will save a significant amount of money over the long term, a comparatively high initial system cost will be a significant deterrent to purchase. Economic yardsticks such as payback, life cycle cost, return on investment, and cost-benefit are all used within the marketplace to trade-off initial cost and expected downstream cost savings. Pretax payback in the range of 2 to 5 years is commonly cited.

Amortization of solar costs through conventional financing is generally the most favorable criterion for comparing annualized solar heating and cooling costs to conventional energy costs. The point at which annual payments for solar equipment equal cost savings of reduced conventional energy use can be taken as the threshold for competitiveness, when long term financing is available. In terms of markets, residential new construction offers the advantages of 30 year amortization of capital costs and reduced installation costs providing the early market for active and passive solar heating. However, perimeter daylighting systems have made initial gains in office buildings, where initial cost and quick payback are the primary criterion. Alternative financing approaches such as third party/vendor financing and shared savings are gradually being adopted by the institutional sector which permit capital improvements for energy systems to be more readily undertaken.

Other, more qualitative factors also affect the marketability of solar buildings technologies. These include reliability, integration with conventional design and installation practices, convenience, amenities, and aesthetics. Widely accepted design configurations also promote confidence in the product by providing proven designs and standard installation techniques. Generic systems are systems with high performance and high reliability which have been synthesized from current industry practice and state-of-the-art research results and which lend themselves to widespread application with only minor modifications. Aesthetics and amenities are also significant market requirements. Passive systems which employ low emissivity glazings in traditional window styles with only modestly larger glazing areas are good examples of technologies that enhance solar performance, while improving occupant

comfort and providing aesthetic appeal. Technologies which provide significant amenities in addition to good performance can be expected to do well in both residential and commercial buildings markets. Growing concern about indoor air quality is expected to add another significant dimension to market requirement for building technologies. Requirements for increased outside ventilation air and control of moisture in building HVAC systems may offer unique opportunities for solar technologies such as solar air preheat systems and solar desiccant air conditioners.

Although the Cost of Energy (COE) is used here as the primary figure of merit for all of the solar buildings technologies, the concept of "delivered energy" has different connotations depending on the technology under consideration. For heating technologies, for example, delivered energy refers to the energy provided to the load from the solar system. This figure of merit accounts for all conversion and efficiency losses that are encountered between the solar resource and the load. In contrast to heating technologies, for cooling technologies delivered energy refers to energy removed from the space. For daylighting technologies the delivered energy is lighting measured in lumen hours (a measure of the energy in the visible portion of the solar spectrum). For purposes of comparison, however, the cost of daylighting is converted to an equivalent cost of electricity ($/kWh) for fluorescent lighting that provides the same lumen-hour lighting output. As such the daylighting COE can be compared directly with utility electricity costs for building lighting.

Figures 1 through 5 are representative curves that show delivered energy costs of solar buildings technologies against the conventional competition. It should be noted that the competition's delivered energy costs should not be confused with fuel costs. They account for the efficiency of the energy equipment (e.g., furnace efficiency, heat pump coefficient of performance, etc.). The curves are presented for both base case and accelerated R&D funding scenarios.

The delivered energy costs of the solar systems were calculated based on stringent market requirements -- equivalent to an all cash system purchase with a required after tax return of 15% (approximately equivalent to a 5 year simple payback). While appropriate for a substantial portion of the market, certain segments of the buildings market have considerably less stringent requirements. For example, institutional building owners frequently take a longer view toward investments and require lower rates of return. Within the Federal government, investments in energy equipment are subject to a life-cycle cost evaluation using a 7%-10% discount rate. Consequently, the delivered energy values used in this analysis are conservative.

It should be recognized that uncertainty exists in these projections. Theses uncertainties are in both the expected technical achievements and the particular time in the future at which they will be realized. In the following sections, the technology advancements that will permit the lowering of the Cost of Energy are discussed. These technology advancements are summarized for active solar water heating, active solar space and water heating, passive solar heating, active solar cooling, and daylighting, respectively. All but daylighting are for

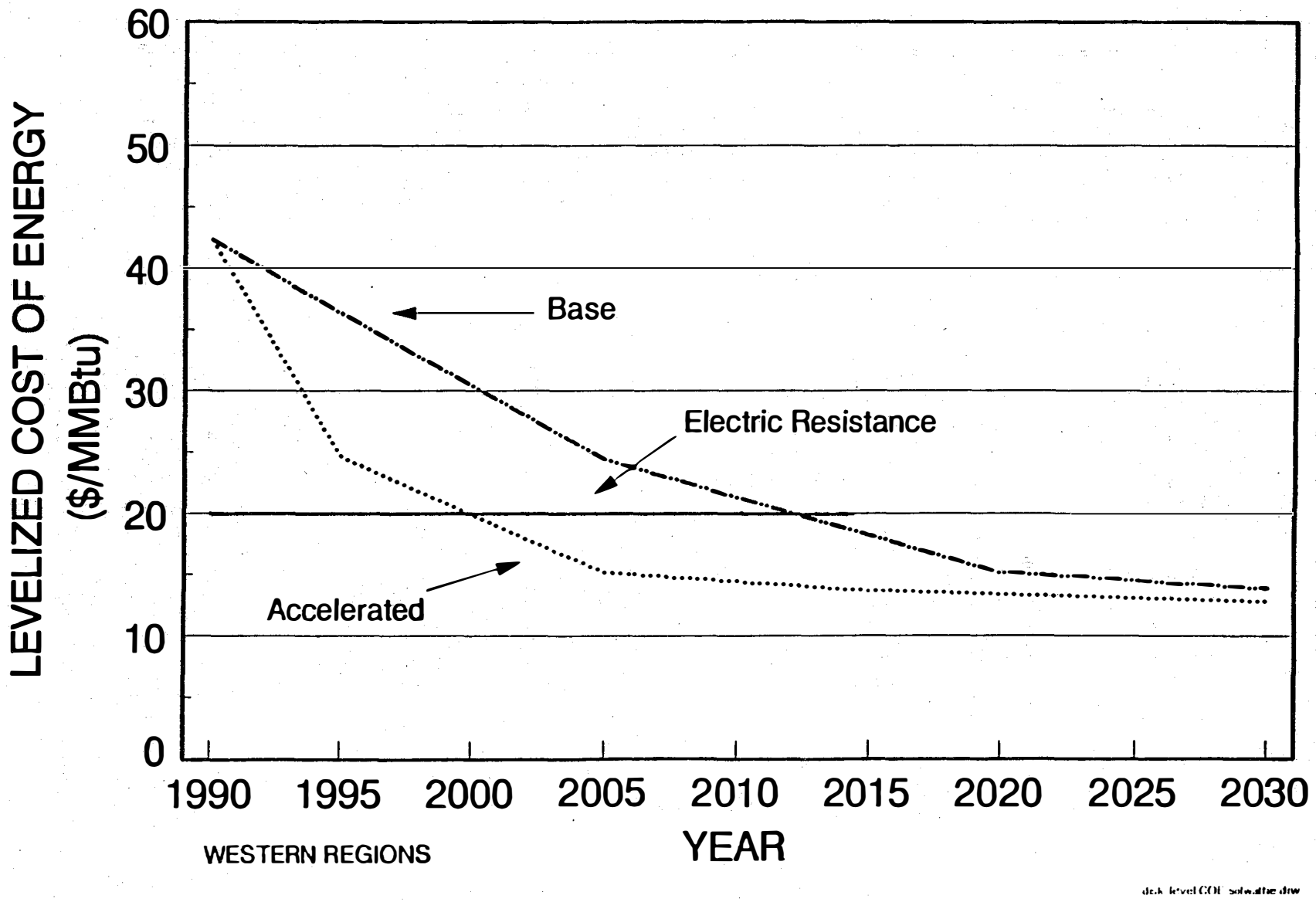

Figure 1. **Residential Active Solar Domestic Hot Water Heating**

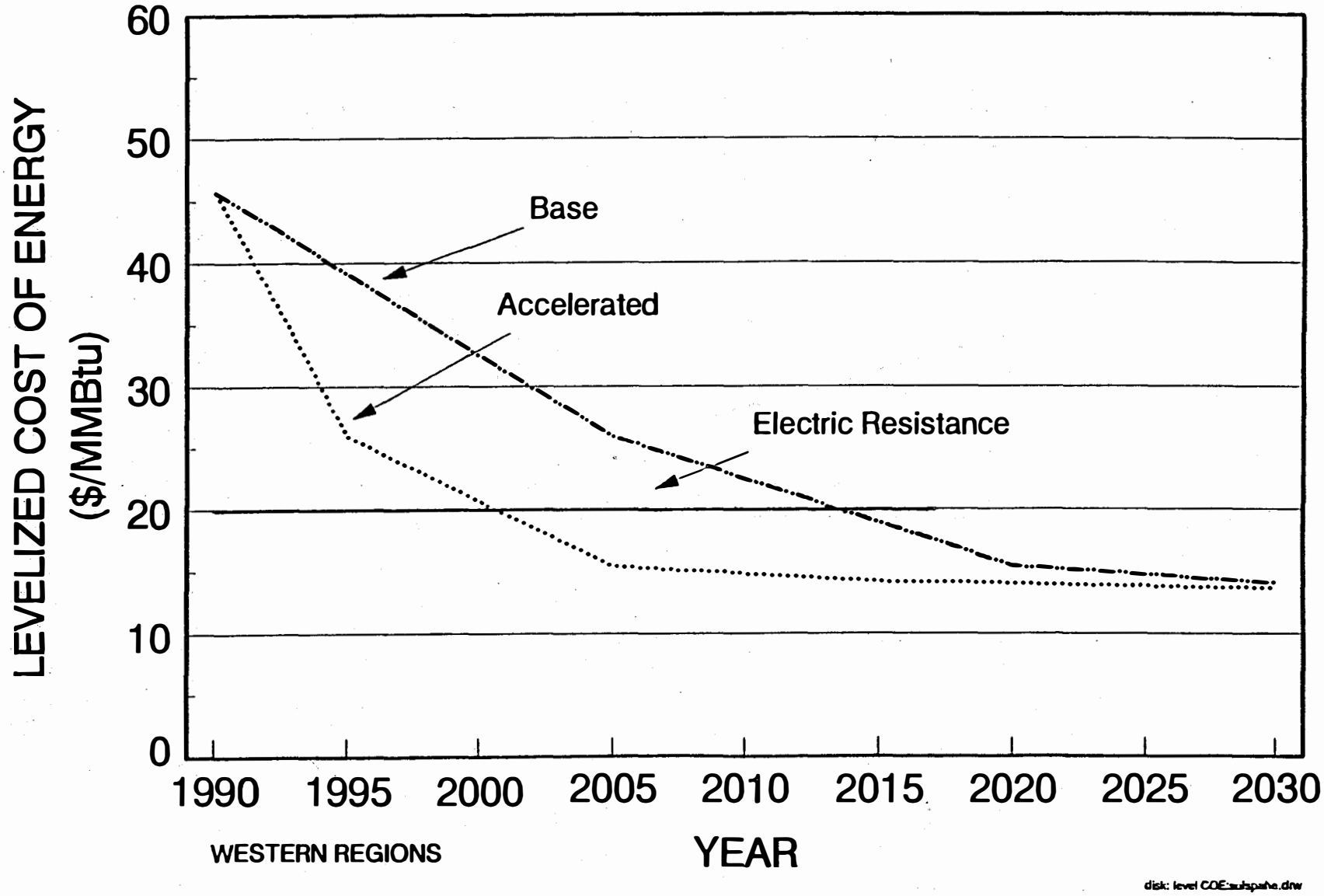

Figure 2. Residential Active Solar Water and Space Heating

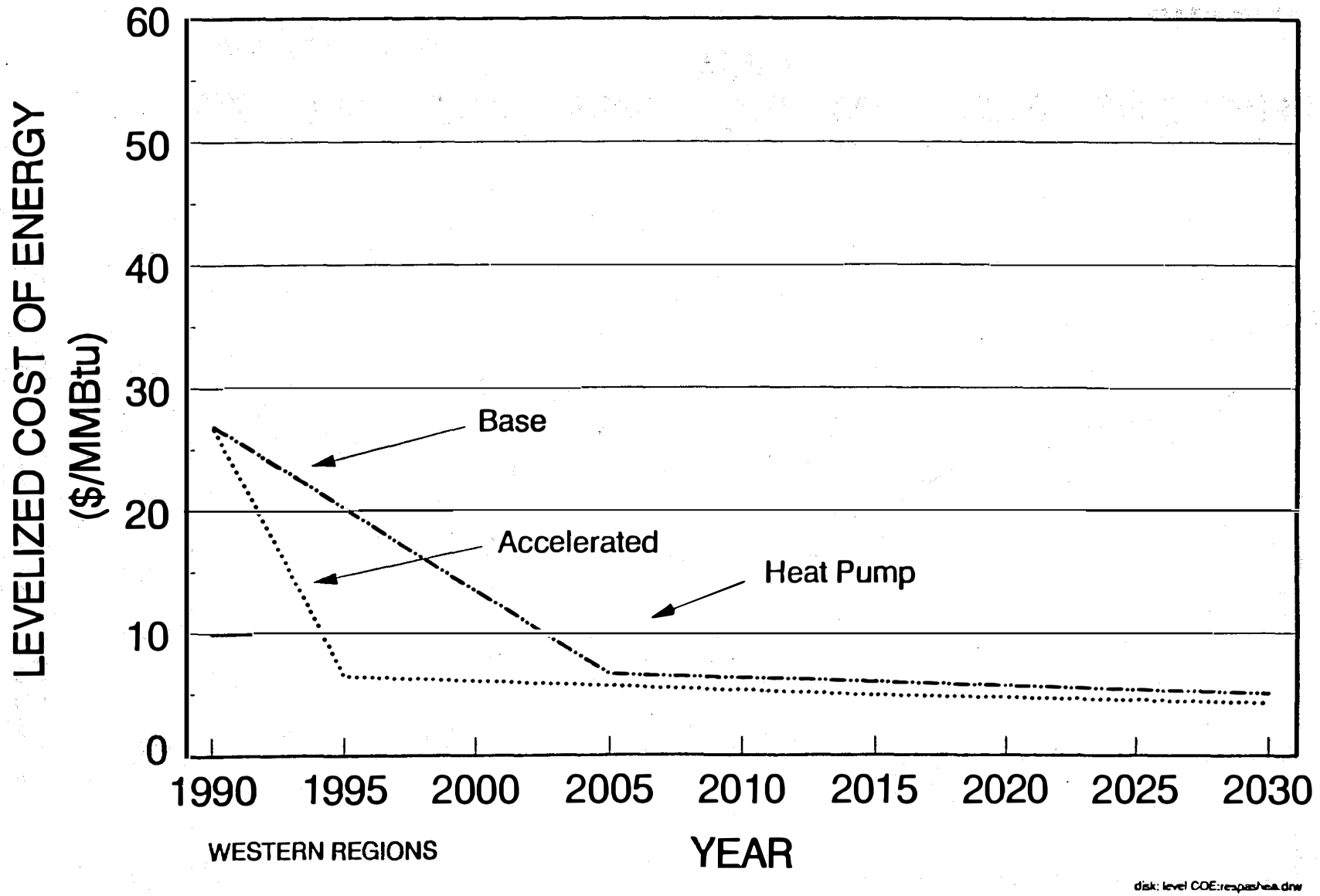

Figure 3. Residential Passive "Direct Gain" Heating

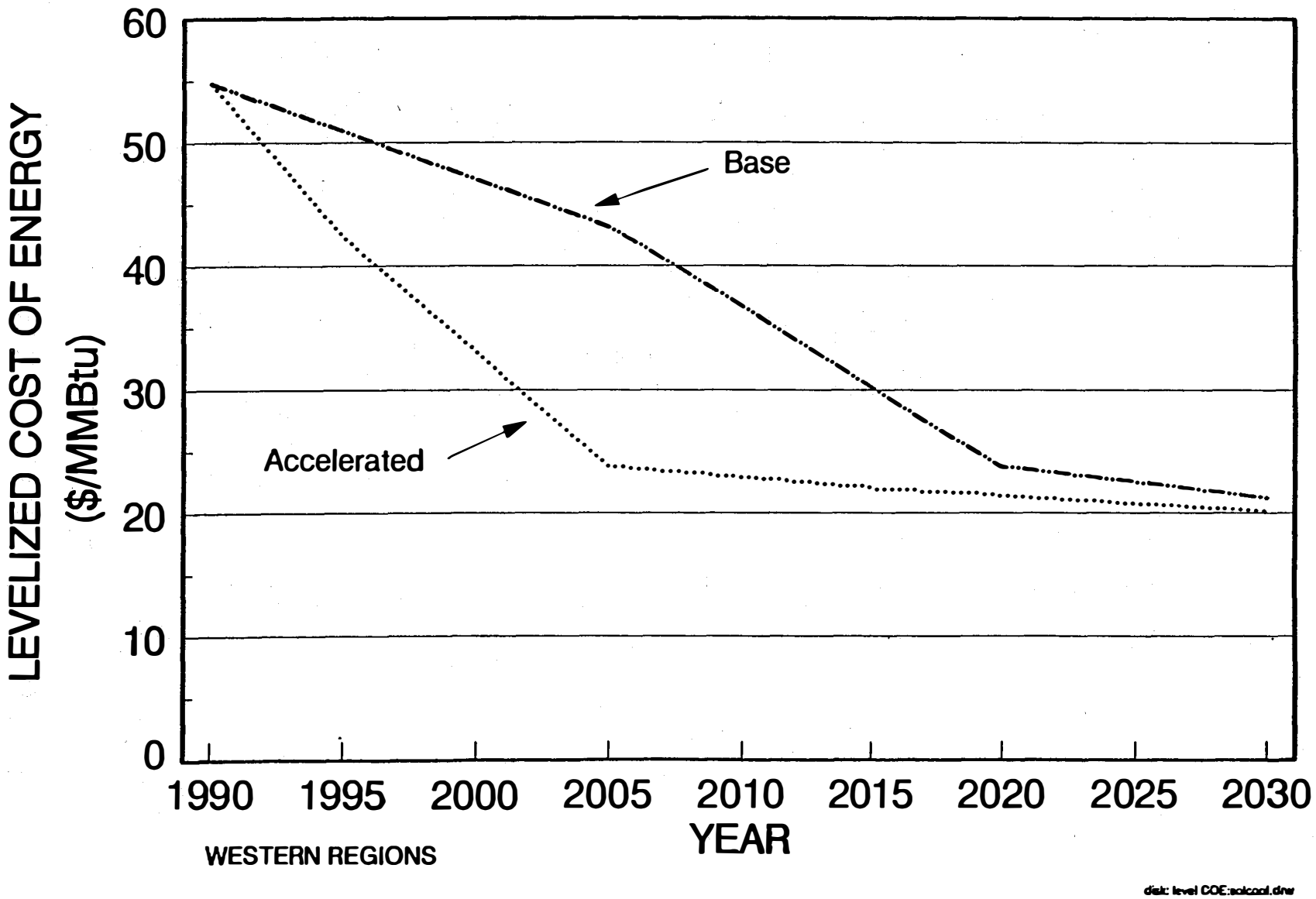

Figure 4. Residential Active Solar Desiccant Cooling

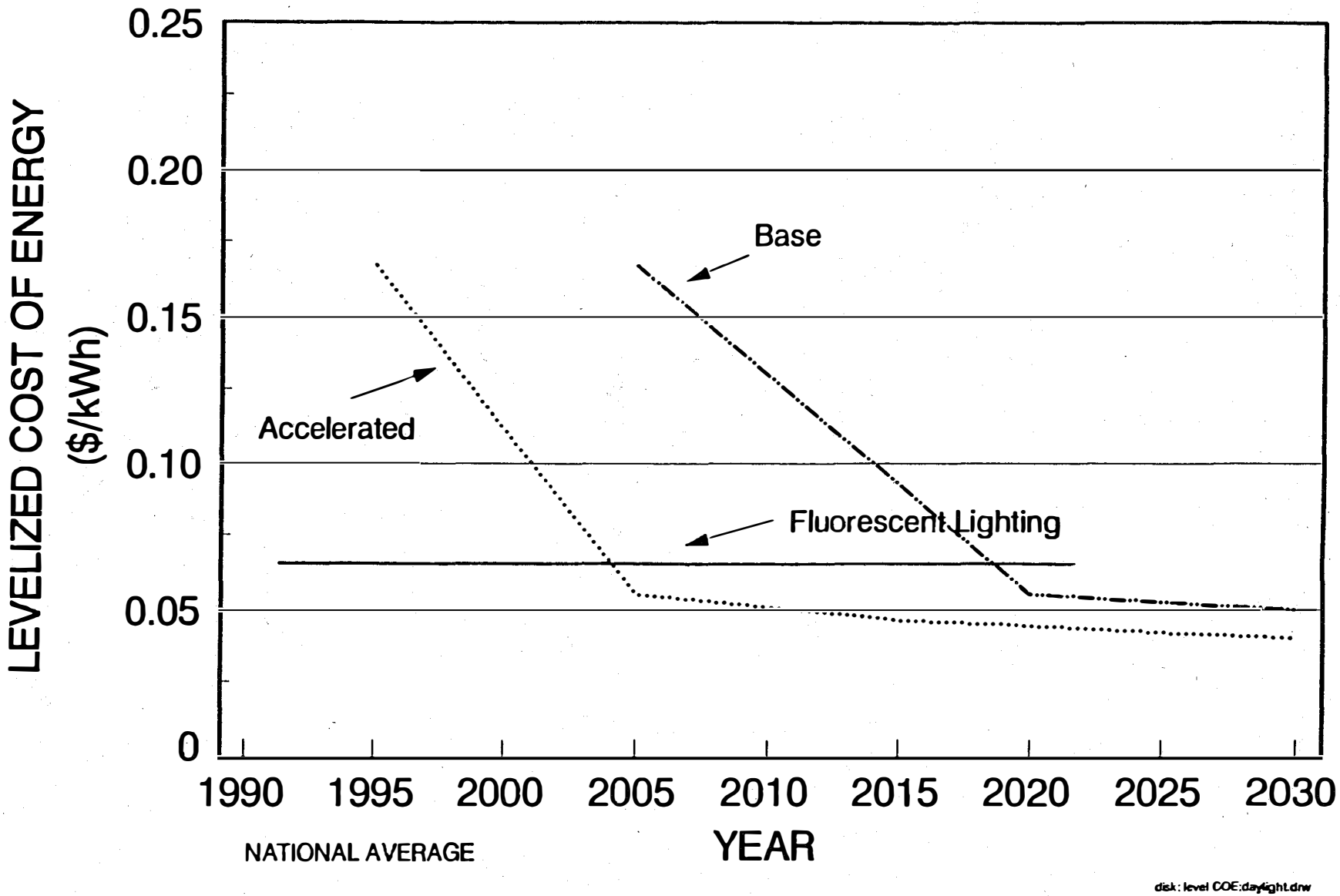

Figure 5. **Perimeter Daylighting with Electrochromic Windows**

residential applications. The daylighting section is aimed at commercial/institutional building perimeter-zone applications.

3.1 Active Solar Water Heating

3.1.1 Base Case Funding Scenario

3.1.1 Research Activities

Under the base case scenario, program activities are devoted to aiding the solar industry, primarily solar collector manufacturers, in incrementally improving current product lines. The focus is on improving industry test and certification procedures and design standardization to improve the average performance of systems and their reliability. This will also have the added benefit of boosting consumer confidence. Research on advanced systems including freeze-protected integral collector storage hot water systems and large scale water heating systems is also supported under this effort. The principal market is expected to remain residential buildings, with the chief competition coming from gas and electric (resistance) type domestic hot water (DHW) systems.

3.1.1.2 Base Case Technology Development Scenario

Table 1 identifies the technology evolution under the base case scenario for active solar water heating. Table 2 provides a detailed breakdown of costs and performance.

No technological breakthroughs are anticipated, but cost reductions should continue, along with modest improvements in system performance. By 2005 the industry will be able to deliver a system that costs approximately 30% less than the 2005 system and be about 10% more efficient. The impetus for these improvements will be the federal program and market requirements. The ability to achieve the system costs projected for 1995 has been demonstrated by at least one manufacturer (Petro Sun of Canada) who made extensive use of light-weight plastic tubing, smaller pumps, and reduced flow pumping strategies. The capability to achieve the performance improvements was verified in laboratory testing conducted by the National Institute of Science and Technology several years ago, as well as by SERI.

Under this scenario, materials research activities needed to develop low cost collectors are severely constrained. Consequently, it is assumed it will be 30 years before a low-cost, light-weight collector is introduced commercially, that has the requisite performance, cost, and durability as defined in the Technology Characterizations document. It should be noted that in the mid 1980's, research on such collectors resulted in a prototype by Reynolds Metals that appeared to meet these characteristics. However, due to market projections the collector never went into production. The other aspects of this advanced system -- low cost storage and improved control strategies -- should be available based on recent experiences. With these advances, active solar water heating should prove economically competitive with

Table 1. Projected Cost of Energy for Active Solar Residential Domestic Hot Water (DHW)

YEAR BASE/ACCEL	TECHNOLOGY DESCRIPTION	PROJECTED COE Hot Water	COST REDUCTION COMPONENTS
1990	• Glass/metal flat plate collector array collector array • Copper piping & fittings • Glass/metal or stone-lined storage tanks	42.6 $/MMBtu	• Current System Technology
2005/1995	• Glass/metal flat plate collector array • Low-flow system • Plastic piping • Plastic storage tanks	24.5 $/MMBtu	• Performance improvements due to uniform design/ installation methods • Low-flow system, reduce parasitics • Preinsulated narrow tube plastic piping and storage tanks introduced, reducing cost • Improved control strategies improving performance
2020/2005	• Thin film flat plate collector array • Selective absorber coatings • Low-flow system • Narrow tube plastic piping • Plastic storage tank	15.1 $/MMBtu	• Lightweight thin film collectors • Low-flow system enhancing tank stratification • Installation costs reduced due to preinsulation, prewiring, piping and quick mount collectors • Replace conventional storage tanks with plastic tanks • Use of thermosiphon heat exchanger to eliminate pumps, reduced parasitics.

Table 2. Cost and Performance Details Base Case and Accelerated R&D Scenario

Active Solar Domestic Hot Water Heating

CAPITAL COSTS ($)	ACCEL	1990	1992	1993	1995	1998	2002	2005	2010	2015 & beyond
Major Components	**BASE**	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
Collectors /Support		900	850	800	750	640	530	420	420	420
Piping/Fittings/Ductwork		309	266	223	179	170	160	150	150	150
Storage/HX/DHW		651	560	470	380	370	360	350	350	350
Controls/Electric		100	100	100	100	100	100	100	100	100
Total Direct Cost		1960	1776	1593	1409	1280	1150	1020	1020	1020
Installation		1161	1027	894	760	657	553	450	450	450
Total Installed Cost		3121	2803	2487	2169	1937	1703	1470	1470	1470
Operation & Maintenance		45	37.5	30	23.5	20	17.5	15	15	15
NET LOAD DISPLACEMENT/ENERGY DELIVERED (MMBtu/yr)										
Regions 1,2,3		10.8	11.2	11.6	12.0	12.4	12.8	13.2	13.6	14.0
4,6		12.0	12.4	12.8	13.2	13.6	14.0	14.4	14.8	15.2
5,7		11.4	11.8	13.2	12.6	13.0	13.4	13.8	14.2	14.6
8,9,10		15.0	16.0	17.0	18.0	18.6	19.2	19.8	20.2	20.6
PARASITIC ELECTRIC LOAD (kWh)										
DOE Regions 1,2,3 - Northeast		94.4	91.6	88.7	85.9	83.0	80.2	77.4	77.4	77.4
4,6 - South		105.5	102.0	98.5	95.4	91.4	87.9	84.4	84.4	84.4
5,7 - Midwest		100.2	97.0	93.8	90.6	87.3	84.1	80.9	80.9	80.9
8,9,10 - West		131.8	129.2	126.5	123.9	121.3	118.6	116.0	116.0	116.0

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electric DHW systems in the west and some areas of the northeast. However, additional fuel price increases will be needed to make it broadly competitive throughout the U.S.

3.1.2 Accelerated R&D Funding Scenario

Only modest increases in funding for active solar water heating is envisioned. However, additional funds would be made available for materials research efforts devoted to both collector and balance of system components for combined active solar water and space heating systems. The results of this effort should be directly applicable to solar DHW systems. Increased international collaboration is also envisioned in the collector area. For example, the Canadians have continued to pursue low-cost thin-film collector concepts, and might prove a valuable partner. As a result of these efforts, the cost and performance improvements are achieved 15 years sooner than in the base case (see Figure 1 and Table 2). Economic competitiveness is achieved against electric DHW systems in the west and some areas of the northeast by the year 2000.

It should be noted that the technology development path includes some advancements attributable to higher performance collector designs using new glazing materials such as aerogels, or convection suppression (honeycomb) films beyond the year 2020. These are being investigated by several other countries as a means of increasing collector efficiencies. If these were to become available, they could increase performance by 15%-20% over current designs, and depending on material costs, reduce the COE as shown in Figure 1.

3.2 Active Solar Water and Space Heating

3.2.1 Base Case Scenario

3.2.1.1 Research Activities

Under the base case scenario, program activities involve low-level efforts focusing on innovative system concepts, and improved design tools. These include ventilation air preheat systems using low cost collectors among others. The base case scenario assumes that the development of combined active solar water and space heating systems will mirror that of solar DHW systems. With the exception of ventilation preheat applications in commercial/industrial buildings, it is anticipated that the market will be primarily for residential applications. The principal competition is from gas and electric (heat pump) systems.

3.2.1.2 Base Case Technology Development Scenario

Table 3 identifies the technology evolution under the base case scenario for active solar water and space heating.

Table 3. Projected Cost of Energy for Active Residential Space and Water Heating

YEAR BASE/ACCEL	TECHNOLOGY DESCRIPTION	PROJECTED COE Space & Water Heating	COST REDUCTION COMPONENTS
1990	• Glass/metal flat plate collector array collector array • Copper piping & fittings • Glass/metal or stone-lined storage tanks	45.8 $/MMBtu	• Current System Technology
2005/1995	• Glass/metal flat plate collector array • Low-flow system • Plastic piping • Plastic storage tanks	26.5 $/MMBtu	• Performance improvements due to uniform design/ installation methods • Low-flow system, reduce parasitics • Preinsulated narrow tube plastic piping and storage tanks introduced, reducing cost • Improved control strategies improving performance
2020/2005	• Thin film flat plate collector array • Selective absorber coatings • Low-flow system • Narrow tube plastic piping • Plastic storage tank	15.2 $/MMBtu	• Lightweight thin film collectors • Low-flow system enhancing tank stratification • Installation costs reduced due to preinsulation, prewiring, piping and quick mount collectors • Replace conventional storage tanks with plastic tanks • Use of thermosiphon HX to eliminate pumps, reduced parasitics.

Table 4. Cost and Performance Details Base Case and Accelerated R&D Scenario

CAPITAL COSTS ($) ACCEL	1990	1992	1993	1995	1998	2002	2005	2010	2015 & beyond

Major Components BASE	1990	1995	2000	2005	2010	2015	2020	2025	2030
Collectors /Support	3750	3542	3333	3125	2667	2208	1750	1750	1750
Piping/Fittings/Ductwork	2500	1992	1483	975	897	818	740	740	740
Storage/HX/DHW	2200	1933	1667	1400	1333	1267	1200	1200	1200
Controls/Electric	500	433	367	300	300	300	300	300	300
Total Direct Cost	8950	7900	6850	5800	5197	4593	3990	3990	3990
Installation	3000	2733	2467	2200	1833	1467	1100	1100	1100
Total Installed Cost	11950	10633	9317	8000	7030	6060	5090	5090	5090
Operation & Maintenance	120	107	93	80	70	60	50	50	50
NET LOAD DISPLACEMENT/ENERGY DELIVERED (MMBtu/yr)									
Regions 1,2,3	32.5	34.2	35.8	37.5	39.2	40.8	42.5	44.2	45.8
4,6	45.0	46.7	48.3	50.0	56.7	53.3	55.0	56.7	58.3
5,7	35.0	36.7	38.3	40.0	41.7	43.3	45.0	46.7	48.3
8,9,10	52.5	55.8	59.2	62.5	65.0	67.5	70.0	72.5	75.0
PARASITIC ELECTRIC LOAD (kWh)									
DOE Regions 1,2,3 - Northeast	476	459	442	425	408	391	374	374	374
4,6 - South	659	630	600	571	542	512	483	483	483
5,7 - Midwest	513	494	474	455	435	416	396	396	396
8,9,10 - West	769	743	718	692	666	641	615	615	615

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The base case scenario assumes that through 2005, the principal cost reductions will result from market forces already in progress. The performance improvements will result from uniformly better design practice as opposed to hardware improvements. This will be aided by the use of improved design tools, particularly personal computer based design software, and updated design manuals. Substantially reduced costs could be achieved by the year 2020 assuming systems based on low-cost, light-weight collectors and balance of system components. Table 4 provides a detailed breakdown of these improvements. Based on the projected cost and performance figures, systems for residential space heating are unlikely to be competitive with either electric heat pumps or gas heating systems. They may prove competitive in niche markets where electric resistance is used for both water and space heating. A small (e.g., 140-180 sq. ft.) system could prove attractive in these applications.

3.2.2 Accelerated R&D Scenario

Additional funding for innovative systems research would be provided for both materials research and system level improvements. Both collector and balance of system research would be supported. Initiatives aimed at industry participation would be launched with specific cost and performance objectives. Such initiatives were used with limited success in earlier program efforts (the innovative packaged space heating effort monitored by SERI). The emphasis would be on systems that could easily be integrated into the building structure to defray costs and improve aesthetics. As in the water heating case the accelerated R&D scenario incorporates some of the potential efficiency improvements associated with certain materials such as aerogel cover plates, and convection suppression films.

3.3 Passive Solar Heating

3.3.1 Base Case Scenario

3.3.1.1 Research Activities

Under the base case scenario, activities are devoted to improved design information and techniques to determine the field performance of passive solar buildings. Some analyses of new materials and concepts is also supported. Much of these efforts are in concert with industry trade groups and IEA. The focus of these efforts is to increase familiarity with passive design techniques and gain greater acceptance in the design community. The principal market is residential buildings.

3.3.1.2 Base Case Technology Development Scenario

Table 5 identifies the technology evolution under the base case scenario for passive solar heating. The technology improvements anticipated for 2005 are based on the introduction of phase change material (PCM) wallboard storage as a substitute for conventional storage materials (e.g., masonry) in passive construction. The PCM/wallboard can be used in place of conventional wallboard throughout a building, not just in the area adjacent to the solar

Table 5. Direct Gain Passive Solar Heating

YEAR BASE/ACCEL	TECHNOLOGY DESCRIPTION	COST/ PERFORMANCE	COST REDUCTION COMPONENT
1990	• Low-E (R-3) Glass Masonry/Tile Storage	$28.2/MMBtu	• Current Technology
2005/1995	• Low-E Glass • PCM Drywall Storage	$6.1/MMBtu	• Replacement of masonry/tile storage with PCM drywall results in significant system cost reduction
2020/2005	• R-12 Glass • PCM Drywall Storage	$5.4/MMBtu	• Replacement of Low-E (R-3) glass with R-12 glass - more than compensated by a 4-fold increase in insulating value, $1.50/sq. ft. glazing cost increase

Table 6. Cost and Performance Details Base Case and Accelerated R&D Scenario

Residential Direct Gain Passive Solar Heating

CAPITAL COSTS ($)	ACCEL	1990	1992	1993	1995	1998	2002	2005	2010	2015 $ beyond
Major Components	**BASE**	**1990**	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
Incremental Costs										
Additional Glass		972	972	972	972	999	1026	1053	1053	1053
Additional Storage		2981	2037	1093	149	149	149	149	149	149
Total Direct Cost		3953	3009	2065	1121	1148	1175	1202	1202	1202
Installation (included)		---	---	---	---	---	---	---	---	---
Total Cost		3953	3009	2065	1121	1148	1175	1202	1202	1202
Capital Cost Credit		335	335	335	335	335	335	335	335	335
Total Incremental Cost		3618	2674	1730	786	813	840	867	867	867
Operation & Maintenance		0	0	0	0	0	0	0	0	0

NET LOAD DISPLACEMENT/ENERGY DELIVERED (MMBtu/yr)

DOE Regions 1,2,3 - Northeast	17.2	17.2	17.2	17.2	18.9	20.7	22.4	24.1	25.9
4,6 - South	15.9	15.9	15.9	15.9	17.3	18.6	20.0	21.4	22.7
5,7 - Midwest	19.0	19.0	19.0	19.0	20.4	22.8	24.7	26.6	28.5
8,9,10 - West	22.8	22.8	22.8	22.8	24.7	26.6	28.5	30.4	32.3

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aperture. This reduces architectural constraints and enables greater design flexibility. It can improve the performance of the solar heating system and could also have potential in shifting cooling loads. Small scale PCM/wallboard units have been developed and tested for a variety of properties -- flammability, toxicity, cyclic durability, thermal performance. In addition, vendor quotes for the principal constituents of the material, indicate that it could be manufactured for the costs indicated. Tests are currently planned to verify performance estimates. However, introduction of the product could be delayed if the leading gypsum manufacturers do not see a sufficient near-term market. With these improvements it is anticipated that passive heating systems could be competitive against electric resistance and electric heat pump systems by 2005, in western regions of the country.

The technology improvements anticipated for the year 2020 hinge on the availability of windows with substantially improved thermal characteristics. (See Table 6 for a detailed breakdown of cost and performance improvements). These windows would have several times the resistance to heat flow of today's windows (R-12 vs. R-3) with equivalent solar transmittance. No solar program support is provided for the development of these windows. It is assumed that industry and federal support from within other areas of the Office of Building Technologies would be available. Currently, windows with R-7 insulating properties have been developed. With these advances, passive solar heating should prove economically competitive with electric resistance, electric heat pump, and gas systems by the year 2020.

3.3.2 Accelerated R&D Scenario

Under this scenario, funds would be provided to complete evaluations of thermal storage materials for both residential and commercial/institutional buildings, as well as for thermal transport concepts. The funding would allow for accelerated testing of PCM/wallboard prototypes leading to earlier introduction by industry. In addition, research on advanced window and building opaque surface materials to improve solar heat capture would be conducted. The greatest uncertainty would still revolve around the availability of the improved R value window. Consequently, some funding for this technology would be provided. This additional support could actually accelerate the introduction of the window resulting in a passive solar heating system that achieves the cost and performance objectives 10-15 years earlier.

3.4 Active Solar Cooling

3.4.1 Base Case Funding Scenario

3.4.1.1 Research Activities

Under the base case scenario, the principal focus is on solar desiccant cooling systems, emphasizing materials research. Substantial reliance on R&D on conventional (nonsolar heat source) desiccant dehumidifiers by the Gas Research Insitute (GRI) and DOE is assumed. These may or may not be optimal for lower temperature solar inputs (less than 180 F supply). The principal market is assumed to be residential, although some commercial applications are possible. A concern with all active solar cooling technologies is that advancements in the cooling equipment (in this case the desiccant dehumidifier) also improve the economics of a conventionally fueled variant of the equipment. This is because the cooling equipment can be driven by any heat source. Consequently, the competition for this technology would be a gas fired desiccant cooling system, as well as a conventional all electric vapor compression cooling system.

3.4.1.2 Base Case Technology Development Scenario

Table 7 identifies the technology evaluation under the base case scenario. The principal advancements involve improving the performance of the desiccant dehumidification subsystem, and reducing collection system and balance of system costs. Table 8 provides a detailed breakdown of these improvements.

Recent experience with rotary desiccant dehumidifiers indicates that a thermal coefficient of performance (COP) of up to 1.0 could be achieved today. A commercial American Solar King (ASK) corporation unit tested at Colorado State University demonstrated this level of performance under favorable environmental conditions. Scale model tests at SERI have indicated comparable performance. Analyses performed by SERI and others indicate much higher COPs are possible with the use of new desiccant materials and efficient dehumidifier designs. By 2005 it should be possible to improve the COP to 1.5 due in part to the use of new polymeric desiccant materials. By the year 2020 it is projected that the COP could be doubled and the cost cut nearly in half by a second generation of improved materials and desiccant bed designs.

The solar components of the system -- collectors, storage, and control -- would benefit directly from improvements to active solar water and space heating systems. It is assumed that the same components -- low cost flat plate collectors, polymeric piping and storage units, etc. -- would be used in the solar desiccant cooling system. The same considerations apply as discussed in the sections on active solar water heating and space heating.

There is a great deal of optimism on the part of the gas industry in bringing gas cooling technologies to the marketplace. In particular, utility demand charges during the summer months provide a great incentive to reduce electric cooling loads. If the gas industry

continues to support demonstrations and field test programs, they could be laying the groundwork for a much broader market acceptance of these technologies than was enjoyed in the past. Consequently, acceptance of a solar driven cooling system could be greatly enhanced. However, even with these considerations in mind, it is unlikely that active solar desiccant cooling systems could prove economically competitive before the year 2020.

3.4.2 Accelerated R&D Scenario

Under this scenario, the materials research effort is greatly expanded resulting in the accelerated development of an improved polymeric desiccant material. System studies and experiments are also supported to optimize solar collection and desiccant dehumidifier subsystems. Some research on active solar absorption systems is also funded focusing on higher temperature evacuated tube collectors and multieffect regenerative absorption cycle machines. Expanded efforts with GRI are envisioned. The net result is to accelerate achievement of cost and performance targets by 15 years. Under this scenario economic competitiveness is achieved earlier against electric vapor compression systems. However, the gas fired desiccant system would prove even more attractive, reducing the overall market share for the system.

Table 7. Projected Cost of Energy for Solar Desiccant Cooling Technology

YEAR BASE/ACCEL	TECHNOLOGY DESCRIPTION	PROJECTED COE	COST REDUCTION COMPONENTS
1990	• American Solar King 3 ton, 10.5 kW desiccant cooling system, dehumidifier thermal COP = 1.0, gas back-up • Parallel passage desiccant wheel rotary dehumidification • Glass/metal flat plate collector array • Glass/metal or stone-lined storage tanks	54.8 $/MMBtu	• Current System Technology
2005/1995	• 3 ton, 10.5 kW desiccant cooling system, COP = 1.5, gas back-up • Parallel passage desiccant wheel rotary dehumidification • Glass/metal flat plate collector array • Metal or plastic storage tanks • Low-flow system • Plastic piping	$42.1 $/MMBtu	• Performance improvement due to desiccant bed design and desiccant material improvement (COP = 1.5) • Low-flow system, parasitics reduced • Preinsulated narrow tube plastic piping • Increased production
2020/2005	• 3 ton 10.5 kW desiccant cooling system, COP = 2.0 • New polymer desiccant material • Thin film collectors • Low-flow system • Narrow tube plastic piping • Plastic storage tank	23.9 $/MMBtu	• Performance improvement due to new polymer desiccant material, rigid polymer structure wheel • Optimized rotary design • Performance improvement, COP 1.5 to 2.0 • Lightweight thin film collectors • Low-flow system stratification control strategy • Preinsulated narrow tube plastic piping • Installation costs reduced due to preinsulation, prewiring, piping and quick mount collectors • Replace conventional storage tanks with plastic tanks.

Table 8. Cost and Performance Details Base Case and Accelerated R&D Scenario

CAPITAL COSTS ($)	ACCEL	1990	1992	1993	1995	1998	2002	2005	2010	2015 $ beyond

Major Components	BASE	1990	1995	2000	2005	2010	2015	2020	2025	2030
Collectors /Support		4200	3967	3733	3500	2893	2287	1680	1680	1680
Piping/Fittings/Ductwork		3000	2500	2000	1500	1400	1300	1200	1200	1200
Dehumidifier		4500	4333	4167	4000	3467	2933	2400	2400	2400
Storage/HX/DHW		2200	1933	1667	1400	1333	1267	1200	1200	1200
Controls/Electric		600	533	467	400	400	400	400	400	400
Total Direct Cost		14500	13266	12034	10800	9493	8187	6880	6880	6880
Installation		3500	3233	2967	2700	2300	1900	1500	1500	1500
Total Cost		18000	16499	15001	13500	11793	10087	8380	8380	8380
Capital Cost Credits		3000	3000	3000	3000	3000	3000	3000	3000	3000
Total Incremental Cost		15000	13499	12001	10500	8793	7087	5380	5380	5380
Operation & Maintenance		200	178	156	135	118	101	84	84	84
NET LOAD DISPLACEMENT/ENERGY DELIVERED (MMBtu/yr)										
-COOLING:										
Regions 1,2,3,5,7		10.0	11.0	12.0	13.0	13.7	14.3	15.0	15.7	16.3
4,6		8.0	9.0	10.0	11.0	11.7	12.3	13.0	13.7	14.3
8,9,10		21.0	22.7	24.4	26.0	27.6	29.3	31.0	32.6	34.3
-HEATING:										
Regions 1,2,3,5,7		21.0	21.7	22.4	23.0	23.7	24.4	25.0	25.7	26.4
4,6		19.0	19.7	20.4	21.0	21.7	22.4	23.0	23.7	24.4
8,9,10		19.0	19.7	20.4	21.0	21.7	22.4	23.0	23.7	24.4
-DHW:										
Regions 1,2,3,5,7		13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
4,6		17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
8,9,10		17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0
-TOTAL:										
Regions 1,2,3,5,7		44.0	45.7	47.4	49.0	50.4	51.7	53.0	54.4	55.7
4,6		44.0	45.7	47.4	49.0	50.4	51.7	53.0	54.4	55.7
8,9,10		57.0	59.4	61.8	64.0	66.3	68.7	71.0	73.3	75.7
PARASITIC LOADS										
-GAS USE (MMBtu)										
DOE Regions 1,2,3,5,7-NE, Midwest		15.0	12.7	10.3	8.0	7.0	6.0	5.0	4.4	3.8
4,6 - South		24.0	20.7	17.3	14.0	12.2	10.3	9.5	8.8	8.1
8,9,10 - West		13.6	11.3	9.0	6.7	5.3	3.9	2.5	2.0	1.5
-DEHUMIDIFIER (kWh)										
DOE Regions 1,2,3,5,7-NE, Midwest		257	261	266	270	282	294	306	306	306
4,6 - South		329	331	333	334	335	336	338	338	338
8,9,10 - West		370	373	377	380	400	420	440	440	440
-ARRAY (kWh)										
DOE Regions 1,2,3,5,7-NE, Midwest		630	644	658	673	698	723	747	747	747
4,6 - South		644	662	680	698	714	730	747	747	747
8,9,10 - West		835	863	891	918	940	962	983	983	983

* 3 ton residential system

3.5 Daylighting

3.5.1 Base Case Funding Scenario

3.5.1.1 Research Activities

Under the base case scenario, the program supports work emphasizing materials research on solid state and laminated electrochromic windows. Tungsten and nickel based electrochromic films continue to receive the greatest emphasis, although other materials are also investigated. Performance and durability evaluations and some system level evaluations are also undertaken. The principal market is expected to be commercial buildings, with standard windows and fluorescent lighting systems being the competition.

3.5.1.2 Base Case Technology Development Scenario

Table 9 identifies the technology evaluation under the base case scenario for optical switching perimeter daylighting systems. Detailed breakdowns of anticipated cost and performance are provided in Table 10.

Although laboratory-scale prototype electrochromic windows have been demonstrated, no scaled up (12" or larger) solid state or laminated windows have been built. By 2005 it is anticipated that a prototype window will be available. The performance targets for the window appear attainable based on the small scale devices tested to date. The cost targets are much less certain since the fabrication techniques and the exact material combinations have not yet been finalized. By the year 2020 a commercial product should be available with the requisite cost and performance attributes. Again, the greatest uncertainty lies in the cost projection. The costs are based on low-emissivity window glass, assuming several deposition layers.

Based on these advances it is anticipated that electrochromic windows would be competitive in virtually all regions of the country by the year 2020. However, they would not be as economically attractive in comparison to conventional perimeter daylighting systems that rely on proper building design and dimming controls.

3.5.2 Accelerated R&D Scenario

Under the accelerated R&D scenario, additional funding would be provided for materials research and prototype testing. These increases would allow for more in-depth investigation of fabrication processes and material optimization. A prototype device could be available for test within 5 years under this scenario, while a commercial product could be available within 15 years.

Table 9. Cost of Energy for Projected Optical Switching Perimeter Daylighting

YEAR BASE/ACCEL	TECHNOLOGY DESCRIPTION	PROJECTED ENERGY COST (¢/KwH)	COST REDUCTION COMPONENTS
2005/1995	• Electrochromic glazing with computer-controlled dimming for fluorescent lights	16.9	• Prototype/limited production systems
2020/2005	• Electrochromic glazing with computer-controlled dimming	5.5	• Improved transmittance range from 15-75%-10-80% • Costs lower through mass production

Table 10. Cost and Performance Details Base Case and Accelerated R&D Scenario

Advanced Perimeter Daylighting System (Electrochromic Windows)

CAPITAL COSTS ($)	ACCEL	1990	1992	1993	1995	1998	2002	2005	2010	2015 & beyond
Major Components	BASE	1990	1995	2000	2005	2010	2015	2020	2025	2030
Incremental Costs										
Glazing (1275 SF)		n/a	n/a	n/a	16575	13600	10625	7650	7650	7650
Controls		n/a	n/a	n/a	5100	5100	5100	5100	5100	5100
Total Direct Cost		n/a	n/a	n/a	21675	18700	15725	12750	12750	12750
Installation (included)		---	---	---	---	---	---	---	---	---
Total Cost		n/a	n/a	n/a	21675	18700	15725	12750	12750	12750
Capital Cost Credit		n/a	n/a	n/a	2250	3750	3750	3750	3750	3750
Total Incremental Cost		n/a	n/a	n/a	19425	14950	11975	9000	9000	9000
Operation & Maintenance		n/a	n/a	n/a	0	0	0	0	0	0

NET LOAD DISPLACEMENT/ENERGY DELIVERED (MMBtu/yr)

DOE Regions 1-10									
Lighting	n/a	74.0	76.5	78.9	81.4	83.8	86.3	88.8	91.2
Cooling	n/a	101.0	105.1	109.2	113.2	117.3	121.4	125.5	129.6
Heating	n/a	-19.3	-19.1	-18.9	-18.7	-18.5	-18.3	-18.1	-17.9

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4.0 RATIONALE FOR TECHNOLOGY IMPROVEMENTS

This section provides information on the technology improvements assumed for the five solar buildings technologies presented in the previous section.

4.1. Active Solar Water Heating Systems

4.1.1 Current Technology (1990-2000)

The basic residential system uses 60 square feet of flat plate solar collectors constructed of copper absorbers with a selective surface (low-emissivity), aluminum housing, a low-iron glass cover plate, and internal headers. A stone-lined storage tank (180 gallon) and copper tubing for interconnections is assumed. A drainback system configuration is used as a freeze protection method. Water/glycol (antifreeze) based systems are also commonly used and would have similar components. The current system costs $52/sq. ft. of collector and can provide 10.8 to 15.0 MMBtu/yr, with solar fractions ranging from 41% to 57% of the annual hot water load. The system lifetimes are estimated to be approximately 20 years.

Mid-term Projections (2000-2010)

Estimates for the mid-term technology characterizations are based on several improvements in both cost and performance. Overall system cost reductions of about 30% and performance improvement of approximately 10% are projected based on optimal system design and uniform installation methods. Collector costs should be reduced by 16% due to increased production. The move to low-flow rate systems could help reduce parasitic load requirements while maintaining array efficiency through better tank stratification. This in turn improves overall system efficiency. Introduction of small diameter preinsulated flexible plastic piping will help reduce distribution system costs by 60% through reduced component cost and system installation time. The use of glass lined or plastic storage tanks will reduce storage costs by 42% for the same reasons. The system costs $36/sq. ft. of collector and provides 12.0-18.0 MMBtu/yr with solar fractions ranging from 45%-68% of annual hot water loads.

4.1.3 Long-Term Projections (2010-2030)

Estimates for the long-term technology characterizations are based on further improvements in both cost and performance. Introduction of new lightweight thin-film collectors that are mass produced offer dramatic cost reductions of about 53% compared to today's base. Together with small reductions in the cost of other system components, and installation costs, this results in a reduction in overall system cost of 53% compared to current technologies. Improved control strategies result in a 22%-32% improvements in performance relative to 1990 technology. The projected system costs $25/sq. ft. of collector and provides 13-20 MMBtu/yr, with solar fractions in the range of 50%-75% of annual hot water loads.

4.2 Active Solar Water and Space Heating

4.2.1 Current Technology (1990-2000)

The basic system uses 250 square feet of flat plate collectors constructed of copper absorbers with a selective surface, aluminum housing, a low iron glass plate, and internal headers. A metal storage tank and copper tubing for interconnections is assumed. A drainback system configuration is assumed for freeze protection. The current system costs $48/sq. ft. of collector and can provide 32.5 to 52.5 MMBtu/yr, with solar fractions ranging from 31% to 51% of the combined annual heating and hot water load. The system lifetime is estimated to be 20 years.

4.2.2 Mid-term Projections (2000-2010)

Estimates for the mid-term technology characterizations are based on several improvements in cost and performance. Overall system cost reductions of about 33% and performance improvement of approximately 15%-19% are projected based on optimal system design and uniform installation methods. Collector costs should be reduced by 16% due to increased production. The move to low-flow rate systems could help reduce parasitic load requirements while maintaining array efficiency through better tank stratification. This in turn will improve overall system efficiency. Introduction of small diameter flexible preinsulated plastic piping will help reduce distribution system costs by 61% through reduced materials costs and system installation costs. The use of plastic storage tanks will also reduce storage costs by 36% for the same reasons. The system costs $32/sq. ft. of collector and provides 37-62 MMBtu/yr with solar fractions from 36%-60%.

4.2.3 Long-Term Projections (2010-2030)

Estimates for the long-term technology characterizations are based on further improvements in both cost and performance. Introduction of new lightweight thin-film collectors that are mass produced offer dramatic cost reductions of about 53% compared to today's collectors. Together with small reductions in the cost of other system components, and installation costs, this results in an overall system cost that is 57% less than the 1990 technology. The projected system costs $20/sq. ft. of collector and provides 42.5-70.0 MMBtu/yr, with solar fractions ranging from 41%-67% of combined annual water and space heating loads.

4.3 Passive Solar Heating

4.3.1 Current Technology (1990-2000)

The primary cost elements of a passive solar heating system are the glazing and the thermal storage. Although certain specialty glazing and thermal storage systems have been developed for passive applications, low-e glazing coupled with masonry storage is the current industry standard. The reference case presented here is a direct gain residential application. The two-story, 1800 square foot building incorporates 190 square feet of low-e glazing on

the southern exposure and 48 square feet on the balance of the walls. Thermal storage is accomplished through the addition of tile-faced concrete floors, beyond the concrete slab assumed for the baseline building. The current system incremental cost is about $14.50/sq. ft. of aperture area, most of which is due to the added cost of storage. The net heating energy provided by the system is 17.2 to 22.8 MMBtu/yr corresponding to a solar fraction of 30%-40%.

4.3.2 Mid-Term Projections (2000-2010)

The bulk of the reduction in COE projected for passive solar systems for this time period will be gained through the substitution of phase change material (PCM) impregnated in conventional wallboard for masonry storage. Typical masonry storage has approximately 3.5 times the thermal storage of PCM wallboard on a square foot basis. As reported by Shapiro, however, PCM impregnation of wallboard costs only $0.30 per square foot compared to the cost of masonry storage of $7.18/sq. ft. One square foot of six inch concrete thermal storage can therefore be replaced by 3.5 square feet of similarly illuminated PCM wallboard with a cost savings of $6.13 per square foot. This cost savings will be reduced if directly illuminated masonry storage is replaced by indirectly illuminated PCM wallboard. However, the cost reductions still approach 75%. This major passive technology advance will reduce system costs approximately 78%. In addition, by removing the requirements for heavy masonry storage systems, passive solar design flexibility is vastly increased.

4.3.3 Long-Term Projections (2010-2030)

Higher performance glazings, with increased R-values and transmittance characteristics similar to low-e (about 70% transmittance) are also projected to improve the performance of passive solar systems. Low-e glazings, with an R-value of 3 are expected to be replaced by R-12 glazing systems. Such systems are being developed using a variety of technologies including multiple-pane metal-oxide-coated glazings coupled with inert gas or vacuum fills. Based on recent experience, comparing low-e with conventional glazing, it is assumed that R-12 glazing will cost $1.50 more per square foot than the low-e system it will replace. Although this substitution represents a dramatic increase in R-value, the cost/performance benefits are more modest than those gained in the thermal storage area, reducing the COE to $5.40/MMBtu. However, the incremental cost for use of the advanced R-12 glazing actually increased 13% from $3.1/sq. ft. to $3.5/sq. ft., but the heating energy provided increases 25% from 22.8 MMBtu/yr to 28.5 MMBtu/yr in the most favorable (western) regions.

Passive heating is capable of supplying over 80% of residential heating requirements. Lesser, but still substantial gains can be expected for small commercial/institutional buildings. However, use of passive heating in larger commercial buildings is currently limited to appropriately oriented perimeter spaces.

It should be noted that no credit has been taken in this analysis for any potential reductions in conventional heating unit size as a result of the passive solar heating system.

4.4 Active Solar Desiccant Cooling Systems

4.4.1 Current Technology (1990-2000)

Currently available active solar cooling systems such as the one manufactured by American Solar King (ASK) utilize an open cycle, parallel passage rotary desiccant design. This system is designed to operate year-round and also provides water and space heating with natural gas backup. The reference system uses the ASK unit of 3 ton (cooling) capacity with a dehumidifier thermal COP=1. The flat plate collector array, utilizes copper absorbers with selective coating, aluminum housing, low-iron glass, and internal headers of the same type described previously for active solar space heating and domestic water heating systems. The same is true of the balance of systems (storage, piping, etc.) This system is capable of supplying solar space heat and domestic hot water in addition to space cooling.
System performance is based on analyses assuming the ASK unit performance. The present system cost is about $5000/ton of cooling or about $54/SF of collector and can meet cooling loads of 10-21 MMBtu/yr (heat removal), heating loads of 19-21 MMBtu/yr, and DHW loads of 13-17 MMBtu/yr depending on regional location.

4.4.2 Mid-Term Projections (2000-2010)

Initial system improvements are projected that will affect both system cost and system performance. Performance improvements of 30% are projected for cooling based on optimized desiccant bed design and material improvements. An 11% cost reduction in the desiccant dehumidification component of the system is projected. The COP is estimated to increase from 1.0 to 1.5. The solar collector system cost and performance improvements are those outlined in section 4.2 on Active Solar Water Space Heating. However, the performance gains have not been factored into the heating and hot water figures. The overall system costs are projected to be $4500/ton of cooling or $38/sq. ft. of collector. The system can provide 13-26 MMBtu/yr for cooling (heat removal), 19-21 MMBtu/yr of space heating, and 13-17 MMBtu/yr for DHW loads.

4.4.3 Long-Term Projections (2010-2030)

The long-term projections estimated further improvements to both cost and performance of the solar desiccant system. Once again, improvements to the solar collection portion of the system have been outlined in the previous section on Active Solar Water and Space Heating. The desiccant cooling portion of the system incorporates a new polymer desiccant materials that also serve as the desiccant wheel's support structure. The use of this material in conjunction with an optimized wheel design, improves the cooling system performance by 50%, and reduces dehumidifier costs by 47% compared to the base system. The improved desiccant material will increase the dehumidifier thermal COP to 2.0 from the 1.0 used in the base system. The overall system costs are projected to be $1793/ton; a 64% improvement over the base system. The system is projected to provide 15-31 MMBtu/yr for cooling (heat removal), 21-23 MMBtu/yr for space heating, and 13-17 MMBtu/yr for DHW loads. Again, these figures do not include performance improvements anticipated for water and space heating.

4.5 Daylighting

4.5.1 Current Technology (1990-2000)

There are no electrochromic glazing systems available. Perimeter daylighting systems use light shelves, skylights, etc. coupled to automated lighting controls (dimmer controls) to achieve daylighting benefits. Automated shades or blinds are available but are generally not used. However, the standard daylighting technologies that are available can often provide a cost-effective means of reducing energy use for electric lighting.

4.5.2 Mid-Term Technology (2000-2010)

The reference system used in the analysis includes first generation electrochromic glazings coupled with dimming controls. Advanced glazing materials such as electrochromics can vary the shading coefficient or transmittance to allow ample visible light and (heat) transmittance in the winter, while providing sufficient light transmittance with reduced heat transmittance in the summer. A computer controlled operating strategy is employed which is designed to minimize lighting electric loads as well as building heating or cooling load, depending on season. The transmittance range of the first generation system is projected to be 15-75% based on discussions with researchers at LBL. Costs for lighting system controls are assumed to be $1/sq. ft. of floor area. A capital cost credit for a reduction in the size of the cooling equipment is included in the total system incremental cost. Performance projections are based on modeling of the perimeter space of a 10,000 sq. ft. interior of a typical office building. The system results in reduced electric requirements for lighting and air conditioning, and a small increase in the requirements for heating. This enables reduction in cooling system equipment size. The reduction in cooling energy requirements and additional heating energy costs are treated as reduced/increased operating costs in the numerator of the COE equation. The delivered energy is the electric lighting energy displaced by the system. The system cost has been estimated to be $15.23/sq. ft. of glazing. The COE is projected at 16.9 cents/kWh.

4.5.3 Long-Term (2010-2030)

The electrochromic glazing system will undergo a performance improvement of 16% based on extending the transmittance range to 10-80% for the next generation glazing systems. Cost reductions of about 54% are expected based on manufacturing mass production. The projected COE is 5.5 cents/kWh.

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