ENERGY LABORATORY

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

ECONOMIC AND MARKET ANALYSIS OF THE PHOTOVOLTAIC TECHNOLOGY

FINAL REPORT

Richard D. Tabors
Utility Systems Program
Energy Laboratory
Massachusetts Institute of Technology

MIT-EL 82-045

August 1982

ECONOMIC AND MARKET ANALYSIS OF THE PHOTOVOLTAIC TECHNOLOGY

FINAL REPORT

Richard D. Tabors*

Utility Systems Program

MIT Energy Laboratory

*The Photovoltaics Project at the Energy Laboratory was under the overall direction of Richard Tabors. Other principal investigators were: Drew Bottaro, Raymond Hartman, Gary Lilien, Lawrence Linden, Thomas Neff, Thomas Nutt-Powell, Martin Weitzman, David O. Wood.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

Foreword

In 1976 the Energy Laboratory of the Massachusetts Institute of Technology began working, initially with the MIT Lincoln Laboratory, to analyse the potential demand for photovoltaic power systems in a range of economic sectors in the United States.* Over the next five years the Energy Laboratory was funded by the Department of Energy (and ERDA) to develop the analytic tools necessary for demand analyses, carry out these analyses and interact with the other laboratories and private research organizations involved in the photovoltaic program. The report which follows is an outgrowth of the work undertaken by the Energy Laboratory. It reports on the research results and on a process developed, that of increasing detail in data and complexity in modeling as the technology itself developed toward a viable energy alternative--i.e., a need-to-know approach. The report covers models developed and analyses carried out. Finally it presents what we believe was learned in the years of analysis of demand for an "unseen technology." It is our hope that the analyses will add to the understanding and future planning of any federal role in new technology development, specifically energy development.

---

*Limited effort was also undertaken in developing the concept and preliminary specifications for photovoltaic powered micro irrigation systems for use in deltaic areas of the developing nations.

Chapter 1

Introduction

Richard D. Tabors

1.0 Background

The energy crisis which began in 1973 brought a major change in attitude on the part of the general population and of government toward security of energy supplies in the short run and structural change in source of supplies in the long run. While major investments in research were generally not seen as solutions to short-run supply problems, such investments were perceived as potential solutions for long-range energy supplies and the implied transition to sources other than imported oil. The sharp increase in world oil prices and the uncertainty in long-term supplies jolted governments and corporations into evaluating or reevaluating a set of technologies which might supply energy from nontraditional sources ranging from the synthetic fuels manufactured from coal to the renewable technologies of solar and wind. By 1976 the U.S. had launched a massive, highly diverse research, development and demonstration program to provide economic alternatives to high-priced and insecure imported oil. These alternative technology programs had similar objectives. Summarized and simplified, these were to:

- Be economically competitive with conventional energy sources by some prespecified date, frequently 1986.
- Be technically capable of providing a significant portion of U.S. energy supplies by some prespecified date, generally 2000.
- Be environmentally benign.
- Be socially acceptable (preferable if possible).

While these objectives were generically easily stated, the pathway to their implementation was frequently less clear.

The majority of the RD&D programs logically began as efforts to improve the technical performance of the individual technological options and had little if any emphasis on understanding the marketplace within which, according to the first objective, the technology was to compete. The technology development programs themselves had a specific flavor in that the first governmental laboratories to become actively involved were those of NASA partly because of marginally employed but technically skilled manpower and partially because of their "mission"-based philosophy toward technology development. The role of private investment in many of the new technologies was limited to large oil companies, some of whose images were being altered to energy companies while others openly admitted a major effort to improve their public image.

This report traces, in part, the development process of the photovoltaic technology, photovoltaics. This was primarily a governmental, not a private, RD&D activity within the United States. The lead research groups, or prime contractors, for the photovoltaic program were either governmental agency laboratories, or Federal Contract Research Centers with only one exception, a University Research Organization. The program followed an aerospace structure in large part. The individual prime contractors were responsible for steps in the development process or for specific alternative systems. The prime contractors administered sets of subcontractors whose output was planned to meet the specific objectives of the prime contractor. Thus the Jet Propulsion Laboratory had responsibility for silicon technology research and development (later changed to development only but for all potential photovoltaic materials such as gallium arsenide and cadmium sulfide). The Sandia laboratory had responsibility for two areas, systems analysis and concentrating photovoltaic technology. NASA Lewis Research Center initially had responsibility for field testing but this was reduced to small systems testing. The Aerospace Corporation (FCRC) had responsibility for "Mission Analysis" and finally the Lincoln Laboratory of MIT, an FCRC, had responsibility for field testing of all but small systems. The program, whose objectives were to meet the marketplace with a product whose fabrication would be in private (nonsubsidized) hands and whose end use would be competitive, was structured around a set of laboratories and research groups who were presently and would remain outside of the market structure. Their primary work to that date had been in either military or space-related research and development.

Initially the technology itself was expensive and designed for space applications. The cost was one hundred times too high and the product was unknown to any but a military/space consumer. Finally the technology was being developed in the public sector (generally nonproprietary development) and the development process itself was split amongst a set of research and development organizations. While the organizational structure appears complex it was a pattern well understood in the space and military programs and one that had a record of success.

There is a difference between a development effort aimed at a space or military mission from one aimed at a conventional market. In addition there is a difference between a commerical product that is for an end use and one that is an intermediate product as is the case with the electricity generated by a photovoltaic energy system. The questions which arise are along three distinct dimensions. The first is one of timing: When does information need to be available in the technology development process? The second question is one of content:

What information is required by the technology development process? The third is one of interaction: Given the nature of the organizational structure, to whom should demand side information flow?

This report argues for a highly integrated technology development program that combines the technical with the economic/market research in an iterative pattern. It argues that the federally funded technology development program can be an effective accelerator into the marketplace for a technology but that the technology must be well understood and the complexities of the market understood but not necessarily solved for the technology to enter. Throughout the report there is an effort to identify the time-dependent, demand-related information required of the basic technology development effort. We argue that demand information can and should be relatively crude early in the development process. As will be seen, this implies specific analytic techniques and requires only minimal technical data as well. Those early efforts help to direct the technology development effort toward those potential market areas that appear most attractive and begin the process of defining the characteristics of the technology which need to be considered by the systems engineers. Assuming additional success in the technology development effort, i.e., promise of decreasing product price, the requirements for demand-side information increase. Product definition becomes clearer and, as a result, the product can begin to be taken into the field for observation by potential purchasers.

- Who needs what data and when?
- What analyses are required at what level of detail?
- When is the process over, i.e., when is the technology in private hands and part of the energy market?

- And finally, how does the role of the government as prime mover change and eventually stop?

2.0 Background to Photovoltaic Technology Development

Previous efforts at defining the role of the federal government in developing markets for new energy technologies have pointed to the fact that there are "stages" or "phases" in the process with inherently different informational requirements and different financial implications.* At each stage, information concerning the functioning of the potential (or actual) market for photovoltaic power systems is required for overall program planning. This information is also required for continued refinement of system designs which provide the combination of system attributes (both economic and technical) valued by likely customers at a cost of production which will bring producers into the market. Such systems are necessary for a functioning market.

To develop this information a set of questions and the analyses required through time to address them are outlined below. The information developed is necessary to understand the functioning of the market for photovoltaics and to aid effective and efficient planning of the government role in the future market for photovoltaic power systems.

Five types of analyses have been developed and implemented at a series of stages in the photovoltaic technology development effort:

User Worth Analyses

---

*For a complete discussion see MIT Energy Laboratory Policy Study Group, "Government Support for the Commercialization of New Energy Technologies," MIT-EL 76-009 (November 1976) and Bottaro, Drew and Paul R. Carpenter, "The Orchestration of Change Through New Energy Technologies," Draft, February 1980.

Market Analyses

Econometric Demand Analyses

- Sectoral
- Non-Sectoral

Industrial Supply Analyses

The program planning and evaluation questions which one addresses by these analyses are the following:

1. In the setting and revision of program goals, how low must system prices be for specific classes of potential photovoltaic customers to be indifferent between photovoltaic power systems and the major alternative, grid electricity, within the relevant market time frame?

- Appropriate Analytic Tool: Simulation analysis with the level of detail determined by the purpose for which the results will be used
- Uses to which the results are applied

  Initial systems design

  Goal development and revisions

Considerable developmental and analytic effort at several research organizations* has gone into use of simulation modeling for initial system design and for development and revision of goals. During the past four years MIT/EL has implemented and tested simulation models of the residential, commercial/industrial and significantly, utility sectors. It has completed a comparative analysis of all sectoral simulation models developed at MIT/EL and elsewhere and in use within the Photovoltaics Program in residential, commercial, and utility analyses. The results

---

*These include the Energy Laboratory of the Massachusetts Institute of Technology, Sandia Laboratory, General Electric and Westinghouse Corp.

should be used as consistent physical, financial and economic assumption sets.

2. What are the market prerequisites which must be met for Photovoltaic power systems to be accepted in the marketplace?

- Appropriate analytic methods

    Survey research

    Market simulation

- Uses to which results may be applied

    Product definition

    Market definition

A number of market penetration models purport to reflect the generalized character of any new product entering a given market. Photovoltaic power systems are, however, significantly different form traditional products handled by market models. THey have not been seen in the market and the product concept is not well understood by the consumer. They have superficial similarities to other energy technologies such as solar heating and cooling and as a result may gain or lose from the association with these earlier technologies. They are likely to be attractive very early to a specific segment of the consuming public. The PV1 model discussed in Chapter 4 has been based upon the previous efforts in market analysis but has evolved from the earlier efforts to include multiple photovoltaic sectors and their interaction. PV1 is also designed to be a growing model in that additional market survey data can be utilized in the continued refinement of the model while the model itself can be used for structuring the collection of market data form the early residential experiments and from other "exposures" to photovoltaics such as that at the Carlisle Photovoltaic

House developed by the MIT Lincoln Laboratory. PV1 has been an increasingly valuable program tool in analyzing investment trade-offs within the Photovoltaics Program.

3. What are the formal and informal institutions which will aid or hinder the acceptance of photovoltaic power systems into the marketplace?

- Appropriate analytic methods
  - Sectoral case study analysis
  - Nonsectoral legal and legislative analysis
- Uses to which results are applied
  - Product definition
  - Legislative and legal responses

It has long been recognized that there are a number of factors neither economic nor physical which will influence the acceptance of photovoltaic power systems in the market. These influences will vary from the normally considered effects of union rules on installation to questions of legislative influence on the acceptance or ease of acceptance of the technology itself. Because the residential, grid-connected market appears to be an early and economically attractive market it has had considerable attention. The work has gone beyond conventional housing with an analysis of mobile and prefabricated homes and the implications of these alternative construction methods for ease of market entry of photovoltaics. In addition, there has been a major effort to analyze the impact of specific legislation and regulation upon the market acceptance of photovoltaic power systems.

4. Given the attributes of a photovoltaic power system, how will potential end users trade off between photovoltaics and alternative systems providing the same level of services?

- Appropriate analytic method: econometric analysis
- Uses to which the results can be applied

  Product definition

  Market definition

  Market size estimation

The attractiveness of photovoltaic power systems to end users will be a complex function of economic and behavioral characteristics and significantly a function of the other choices in electrical consuming technologies within the household. The demand for electricity is derived from appliance needs and hence electricity fulfills no function independent of a set of appliances which provide the services demanded by the homeowner. An understanding of the homeowner's trade-off between capital and operating costs for major appliances as well as for photovoltaic systems will play a major role in developing predictions of the size of the photovoltaic market. This analysis is required late in the development process but has required the development of new analytic methodologies which allow for analysis of trade-offs in "attributes" of the individual technologies. The second stage in this activity has been to gather and analyze data on consumer trade-offs between capital and operating costs for a set of large consumer durables such as hot water heaters and heating systems for homes.

5. How will the photovoltaic industry respond to the developing photovoltaic market?

- Appropriate analytic methods

  Simulation analysis

  Survey research
- Uses to which results may be applied

Supply side growth projections

Market size estimation

As photovoltaic technology develops, it attractiveness to investors increases and investors are more likely to invest in photovoltaics. However, questions concerning the rate at which investment in new plants will occur, the size of the plants, the nature of the evolving market structure, the responsiveness of investors to incentives and the desirability of establishing incentives must be addressed if the ultimate success of the program is to be achieved. To date the planning emphasis has been on cost reduction and the study of the different market sectors; the growth of the supply side has been assumed once the rational consumer's "break-even" price was reached technologically. The logistics of development of a photovoltaics supply industry have been overlooked, as production capacity cannot be installed instantaneously. The structure of industry has also been assumed implicitly, with program assumptions being that highly vertically-integrated plants will be the ones built.

While some surveys do give a confident feel that one has the "inside" facts, their shortcomings for forecasting are numerous, especially the possibility of strategic responses by interviewees. The alternatives of econometric estimation of investment behavior would suffer from inadequate data. Construction of a supply-side version of PV1, which would delineate the relationships among the varables and then simulate investment using survey data combined with theoretical underpinnings, would give both the required flexibility and the most expandable structure. While this modeling structure is introduced, its development and testing are not described in this report.

6. What is the role which the electric utility industry within the United States can and should have in fairly dealing with the potential impact of photovoltaic generation, particuarly distributed generation into their service areas?

- Appropriate analytic methods
  - Simulation analysis
  - Optimization analysis
- Uses to which results may be applied
  - Utility capacity planning
  - Rate negotiations

For photovoltaics technology to have any significant impact on the U.S. energy market, it will be necessary for the price of photovoltaic systems to be at least competitive with grid power. There is, however, a need for the utilities within the U.S. to recognize the potential value of photovoltaic systems operating in their districts and to cooperate with the photovoltaic power producer. While this cooperation is mandated by Sections 210 and 210a of P.L. 95-617, the complete coordination will require considerable mutual education between the photovoltaics community and the electric utility industry. A portion of this mutual education is currently under way in the development of a set of planning tools for the electric industry which are familiar and "legitimate" to the industry and which can be used to analyze both the central station and distributed photovoltaic power systems integrated with the grid. At the first stage it is possible to use only operating system models such as MIT's SYSGEN. More detailed analysis requires new tools to evaluate the capacity planning and uncertainty implications of integration of the the photovoltaic technology. In such an analytic structure, the Electric

Power Research Insititute allows for the evaluation of the nondispatchable technologies such as photovoltaics on equal footing with traditional technologies in a capacity expansion framework.

3.0 Report Structure

The chapters which follow suumarize the research findings of the MIT Energy Laboratory during the photovoltaics project. The chapters include references to the major research reports completed. In addition there is a complete bibliography at the end of this report which covers all of the technical reports and working papers prepared during the length of the contract. It should be pointed out at this time that there was a learning curve associated with the project during its duration and thus specific conclusions in earlier reports may be superseded by later reports. The effort in this final report has been to identify those conclusions most current.

The second and third chapters of the report discuss that area of the analysis most fully developed by the MIT Energy Laboratory, the worth analysis related to grid-interconnected, primarily residential applications for photovoltaics. The second chapter looks specifically at the value of residential photovoltaic power systems interconnected with the grid and, to a lesser extent, with both photovoltaic thermal systems and with photovoltaic power systems with electrical storage. Chapter 3 addresses the issues of the value of photovoltaic systems to the utility system in which they are interconnected. An appendix to Chapter 3 presents briefly the results of a joint research effort between DOE photovoltaics and EPRI in developing the capability to model photovoltaic power systems in a standard utility capacity planning structure. This work was part of the Electric Generation Expansion Analysis System research effort at the Laboratory.

The fourth chapter discusses the background and development of the market model, PV1, developed at MIT. It further summarizes the results of a set of initial market survey studies done in conjunction with the Residential Photovoltaics System.

The fifth chapter presents results from two studies conducted by the MIT Energy Laboratory of the DOE Solar Heating and Cooling Program and of the potential consumer response to that program. This research was a portion of an overall effort early in the project to understand the process by which the government can influence the acceptance of a technology through introduction in the "correct" information channel. Work not discussed in detail in this report was focused on the first large-scale photovoltaic experiment at Meade, Nebraska, where detailed survey and process materials were gathered, studying the channels for innovation, introduction and acceptance in the agricultural sector.

The sixth chapter addresses the project efforts in evaluating and monitoring the impact of PL 95-617, PURPA, and its rate-setting procedures covered under Sections 210 and 210a.

The final chapter summarizes the lessons learned in the process of governmental involvement in the photovoltaic technology development program.

Each of the chapters listed above is independently authored and contains material that is the direct result of individual research activities of the authors. As with the project as a whole, many individual pieces have been brought together in this report to make an overall evaluation of the market entry process of the photovoltaic technology.

Chapter 2

Residential Photovoltaic Systems: Summary of Worth Analysis

Thomas L. Dinwoodie

Richard D. Tabors

1.0 Introduction

The period from 1974 to 1982 saw the refinement of the photovoltaic cost goals that have guided the technical development work. The critical parameters were identified and a fair level of confidence now exists in the established range of allowable costs. Looking from 1982 to 1990, there is strong evidence of market trends that are significant for PV. Some of these trends have impacted the latest allowable cost analyses, while others are mere indication of a changing market climate, one that bodes well for the institutional and consumer acceptance of PV. And for the post breakeven-year time frame, the latest models have been adjusted to examine the purchaser perspective. PV has been analyzed for its investment figures of merit--in terms identifiable to both a homeowner and institutional decision-maker.

The purpose of this chapter is three-fold. First it is to create a perspective on the role and significance of worth analysis in PV and similar program development. Here, PV development is divided into the three time frames just described. For the first, 1974 to the present, the several studies performed to date are described in terms of their response to the evolving questions of PV economic worth. That period from the present to the PV break-even years defines the interim time period. Discussed here are several trends that will play a more or less direct role in the ultimate acceptance of PV technology. The final time frame is that of the post break-even years. Here PV worth from the investor perspective is discussed.

The second purpose of this chapter is to define the significant parameters affecting PV economics and to present results of the latest studies establishing allowable costs and investment figures of merit. There are three region-specific parameters that most significantly impact the value of photovoltaics and thus a simplified analysis of PV investment worth on a U.S. regional basis is presented.

A third purpose is to characterize and assess alternative residential PV configurations. Results are summarized for studies that examined photovoltaics and storage, PV/thermal (PV/T) combined collector systems, and the difference between retrofit and new construction PV applications.

2.0 The Chronology of Photovoltaic Worth

2.1 1974 - 1982: Reducing the Several Studies

Price goals for PV energy conversion systems were first articulated by the NSF and Energy Research and Development Administration (later the Department of Energy) in the fall of 1973. At that time it was stated that large-scale PV applications would become economically viable by the reduction of solar array costs to less than $\$0.50/W_p$ (module only). This goal represents $\$0.70/W_p$ in 1980 dollars. In 1977, the Jet Propulsion Laboratory, through its Low Cost Silicon Solar Array (LSSA) Project reiterated this $\$0.70/W_p$ price goal.[2] A year later, Carpenter and Tabors[3] at the MIT Energy Laboratory established a new set of cost goals after first proposing a uniform valuation methodology to account for the unique factors impacting the economics of photovoltaics. As typical with more detailed methods, the analysis inspired as many questions as it produced results. What was the utility buyback rate?

What was the array size? How much did the sun shine? What was the system efficiency? What was the purchaser discount rate?

Under equally probable scenarios, the break-even cost of a PV module (excluding balance of system, e.g., support structure, inverters, wiring, etc.) now varied from $0.40/$W_p$ to $2.00/$W_p$ (1980 dollars). But the critical parameters were being identified. Utility rates, homeowner discount rate, tax credits and the amount of sunshine.

Several studies were performed to assess photovoltaics in alternative configurations, such as with dedicated or system storage (batteries and flywheels), PV/T combined collector systems (liquid and air), and remote, stand-alone aplications. Such studies were useful to assess the merits of alternative funding allocations. If batteries made photovoltaics look better, should the PV program take an active interest in funding storage R&D?

The valuation models soon exceeded their mandate to establish cost goals and looked for other, investor-side figures of merit, including net benefits, rate of return, and payback. As the models grew more sophisticated, sensitivity studies were addressing such investor-specific issues as the impact of a change in homeowner marginal tax rate in year 5 vs: year 7. The models were no longer policy tools, but rather the companions of the private-sector financial analyst. The important policy questions were very nearly answered.

The latest round of break-even cost figures using mortgage finance cash flow analysis and the latest estimates of prevailing 1985 market and finance conditions show allowed costs in the range of $1.50/$W_p$ (Madison) to $3.00/$W_p$ (e.g., Southern California) for a complete, installed system (1980 dollars, without tax credits). If tax credits are assumed, these figures are increased proportionately, and significantly.

Many new findings have accompanied these later studies, particularly in terms of changed expectations. First, the non-PV module portion of the total residential system represents a significant portion of the total system cost and deserves increased attention. This "balance of system" includes array support structures, inverter, wiring, installation and maintenance. Second, the later studies assumed substantially higher utility buyback rates as a result of the avoided cost requirement outlined by PURPA. Third, utility electricity rates were not to escalate at the rates assumed by the earlier studies--probably0 to 2% (real) in the long term and not 3 to 6%.

2.2 1982-1990: A Changing Market Climate

For various political, economic and psychological reasons, the market environment for photovoltaics in the grid-connected break-even years will be vastly different from that being entered by most renewable energy technologies today. Innovation in marketing and finance, a growing strength and breadth of the renewables industry, and changing utility interests and attitudes will aid in creating a natural climate for photovoltaics. The following is a review of some of these trends.

2.2.1 Marketing

The more successful renewable energy financing schemes are likely to be institutionalized by the PV break-even years. Here are just a few examples of evidence:

The marketeers of solar heating systems in the early 1980s have begun to understand the world of innovative finance. A trade magazine[4] reported in October, 1981 that a San Francisco based financial corporation was contracting with three major U.S. textile mills for the sale of process steam at a guaranteed rate 10% below the equivalent cost for steam from oil or natural gas. The marketeers have realized that industrial users have need for steam, not football fields of hardware. And perhaps more important, steam that is purchased can be expensed.

In California, large-scale leasing of residential hot water systems is mushrooming as financial firms, utilities, and suppliers are cooperating under numerous incentives.

In Hawaii, California and New England, land-lease arrangments struck by windfarm developers are advertised as no-cost, twenty-year, steady income options to the landowner.

2.2.2 Industry Prowess

The renewables industry is fast developing a very important broad base. Wind turbines are built with off-the-shelf components from suppliers to the automotive and other industries. Future DHW collectors will require the best plastics made by duPont, 3M, and others. In the Midwest, major distillery companies are investing in ethanol refineries. Large corporations are taking more active roles, often with apparent conflict of conventional interest.

The significance of all this is perhaps dramatized by two recent events. First, Standard Oil recently acquired a major westcoast windfarm development corporation and has joined Brooklyn Union Gas in a court dispute against Con Edison over PURPA. Second, the Reagan Administration announced in September, 1981 its interest in rescinding the conservation and renewable energy tax credits. In only a matter of weeks, both the House and Senate had majority signatures on resolutions opposing such an action.

These are indicative of significant turns for the renewables industry. Policies favorable to alternative energy development are becoming also the special interests of larger corporations. And the constituents of the renewables industry are waking to the necessity of "lobbying clout".

2.2.3 Utility Financial Health

Many utilities are now actively pursuing alternative energy development. Several have established acquisition quotas for "alternative" capacity within fixed time periods. One reason for the change concerns perceived financial health. A report prepared in September 1981 by Merrill Lynch Pierce Fenner & Smith Inc. states:

> We view utilities that are developing alternative energy technologies or that now have such technologies in place, including renewable resource systems, as favorable for investors in public power or private investor-owned utility bonds. Alternative technologies and conservation offer the advantages over traditional energy sources of shorter lead times, greater flexibility (due to smaller plant size), reduced capitalized interest requirements, elimination of uncertain fuel costs, and more predictable fuel availability.[5]

And within the summary of the same report:

> We think that public power bonds now offer attractive yields and the gradual influx of alternative technology financings should continue to buoy yields to unprecedented levels. As the cost of power increases and demand continues to ebb, investors should avoid investment in utilities with capital requirements for ongoing construction programs which will produce large excess capacity, and try instead to find utilities that are open-minded in evaluating conservation and alternative technologies. We anticipate the growth of alternative technology financings as economics and state-of-the-art engineering techniques make them more cost-effective, and utilities and investors become more receptive.[6]

2.3 1990-2000: The Investor Perspective

Several studies have been written to establish cost goals for residental PV systems in alternative environments and configurations. These studies have been instrumental in establishing cost targets necessary to bound the objectives in the technical development work. Although seldom consistent in their precise method of evaluation, they have in general been consistent in taking account of rational investment criteria of the purchaser and end user. A comparison of those methods is provided in Appendix A to this chapter.

On the purchase side, however, it is the homeowner who chooses photovoltaics, whether for retrofit, or as part of the package of a new home. It is the lender who finances either way. What numbers will these two parties be looking at?

In this section we ask the question strictly as we see it being examined in the years that residential PV systems are first being introduced. "Should I invest in photovoltaics for my rooftop?"

You are a homeowner in the late 1980s. You have heard talk of PV systems now and then amongst friends and a few times have seen specials on the news. In the last week alone you saw a commercial on TV and received a flyer in the mail. The Journal had an article the other day talking about the influx of Japanese systems on the west coast. And Pat Richards bought a system 8 months ago but has had at least one problem with vandalism. Some kids tossed a paint balloon. With otherwise no particular inclination to consider an alternative or supplement to uility power, you think, is this stuff cost-effective?

You perform the calculations. Over $100/month is spent on the electric bill (1986 dollars). The roof is large and flat and could easily accomodate 60 m^2 of collector area. PV systems are roughly 10% efficient and you remember from the solar domestic hot water study that there is roughly 1 kW per m^2 of peak solar insolation. A 60-m^2 system will therefor produce 6 kW of output at peak. The thermal collector study also pointed out that one should divide the peak (noon-hour) output by roughly a factor of five in this region to get the average power output, given the cycle of the sun. So six over five is 1.2-kW average output times 24 hours per day times 30 days per month times your utility rate of 13.6 ¢/kWh. That is $120/month, just above what you are currently paying each month. Times 12 months is $1440. But the system advertised the other night on TV was $12,900, making it close to a 9-year payback.

You locate the flyer in the trash and find that the government has extended the 40% residential tax credit to PV systems. With a limit of $4,000, the tax credit reduces the cost to $8,900 making payback roughly 6 years, or maybe better if those rates keep going up. You look again at the flyer. The cost of their system at 60 m^2 is $12,000, and they have provided sample cash flows to present to your banker. The system has a UL label. And here they have a second option. You can lease a system, retain the option to purchase, and they will bill you monthly at 10% below what would otherwise represent your electric utility bill. This would certainly be your choice given the cost of that recent home computer upgrade. What is there to lose?

You think again of those vandals. And you think it will be worth another word with Pat Richards at the ballgame on Friday.

The scenario above is not dissimilar to what homewoners are experiencing in 1981 with the drive to market flat plate solar thermal collectors. The first push is in the western sun-belt states, but photovoltaics will look equally attractive in New England, New York, and elsewhere where utility rates are high (see Section 4). Back of the hand calculations, marketing literature with pro forma cash flows, innovative leasing terms and positive PR from early, successful systems may suffice for a call to a banker. The number of initial system failures will have major impact upon the ultimate penetration of the more reliable systems. Purchased systems, whether outright or debt financed, will be typical for certain, wealthier classes of individuals. The early purchases will be made by those inspired by nonmonetary benefits, whether that be a certain level of energy independence, the prestige accompanying the use of a new technology, or the social value of using energy with reduced environmental impact. The "no-lose" innovative finance schemes will attract the larger market.

3.0 PV Worth: The Latest Analysis

A new round of PV break-even cost figures was generated at the M.I.T. Energy Laboratory in October, 1981. The study utilized a mortgage finance cash flow model with projections of market and financial conditions for 1986.[7] This section presents the results of that analysis as follows. First is presented a single sheet sensitivity summary of the more critical parameters impacting the analysis. This serves as caveat to interpretation of the allowable cost figures presented immediately following. Small changes in critical assumptions can have a large impact on the final result. It is found that the major critical parameters are geographic region-specific, e.g., amount of sunshine, local utility rate and available tax credits. A series of cash flow investment analyses provides a detailed look at the impact of these parameters. Section 4.0 presents a more generalized and simplified regional analysis for the entire U.S.

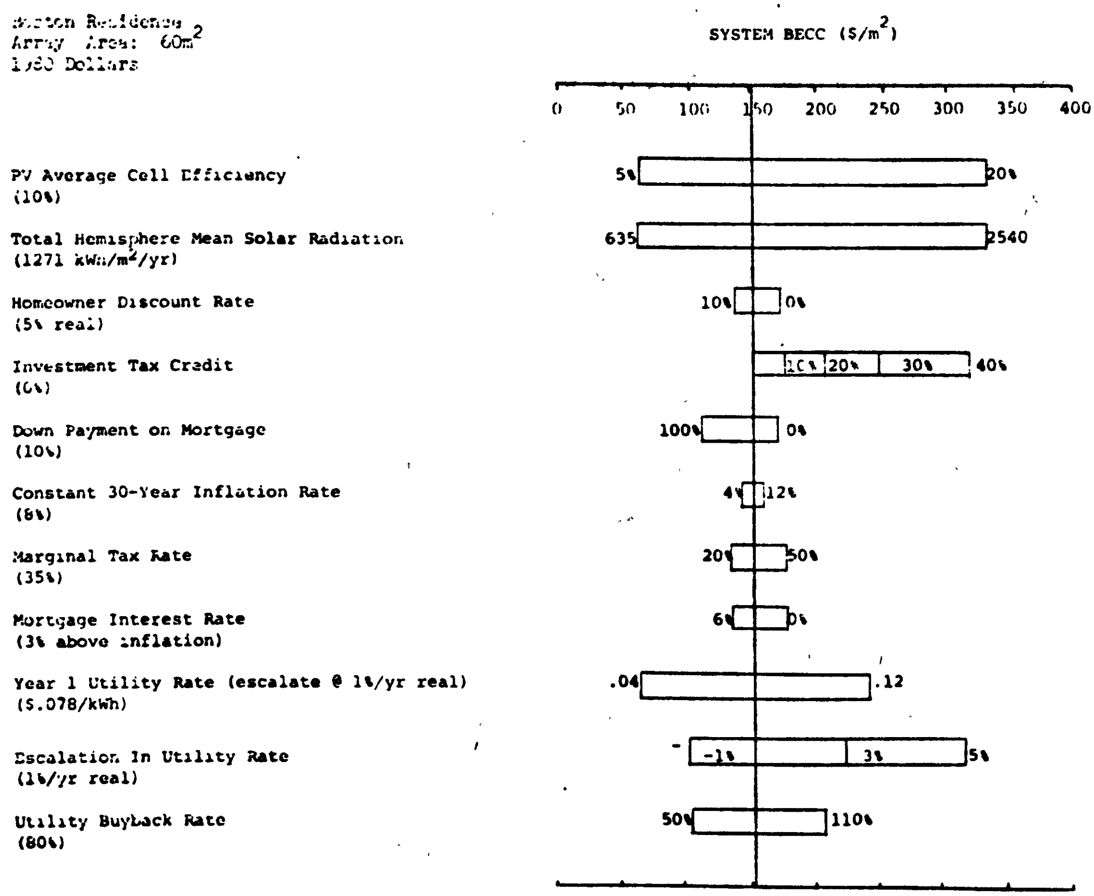
3.1 The Critical Parameters

There are four critical reasons why it is impossible to project a single number for PV allowable cost. First one must predict the performance of the hardware, which may be summarized by an overall system efficiency, but which must also consider system life and reliability. Second, one must specify the geographic location to know the characteristics of the sunshine available and the local cost of utility power. Third, one must anticipate how the system is to be financed and what the characteristics are of the investor. And lastly, it is necessary to predict, as of the purchase date and 20 or so years hence, just what will be the prevailing market conditions, such as inflation, electric rate escalation, and utility buyback rates.

Some of these parameters are more critical than others. Figure 1 presents a grand summary of their relative weight in the end analysis for photovoltaics. The break-even capital cost was calculated for a 60-m^2 PV array atop a residence in Boston. Along the left column of the figure are listed the more variable parameters, followed by assumptions concerning their probable value in 1986. Reasonable deviations from these values are listed on either end of the sensitivity bars, which indicate the corresponding change in system allowable cost. For example, a 40% tax credit shows roughly the same impact as placement in an environment with twice the annual average insolation. Relative to the range of likely interest, inflation or homeowner tax rates, these factors have enormous influence.

It is clear from the analysis that the most critical variables include overall system efficiency, amount of solar insolation, the available tax credit subsidies, and utility purchase rates and their

Figure 1



Sensitivity Study - Parameter Comparison

Mortgage Financing of Residential PV

escalation.

3.2 Allowable Costs

There are two principal, converging perspectives on PV worth. One is that of the researchers and manufacturers, in search of cost "goals" and guidance on the relative merits of alternative funding allocations. The other is from the standpoint of the purchaser, in search of a worthy investment. For the former is established an allowable cost, often defined in the PV literature as the break-even capital cost, or that cost at which an investor would be economically indifferent to purchase of PV versus sole reliance upon the local utility. To the purchaser must be demonstrated a handsome return on investment. Of course the two methods must converge, i.e. the break-even capital cost is, by definition, that cost at which net benefits in a cash flow analysis are precisely zero.

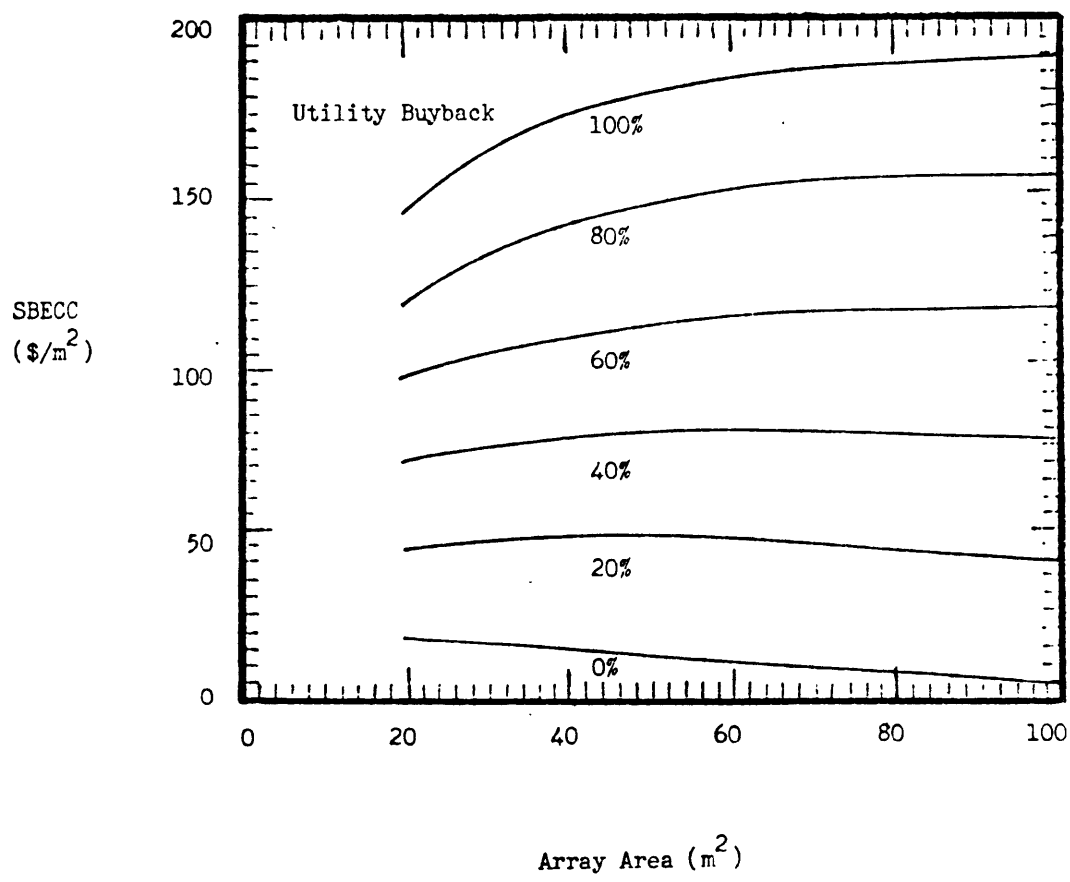
The previous study demonstrates the problem with defining allowable cost targets for a generic residential PV system. Nevertheless, cost goals are summarized in Figure 2 for a Boston residence. The purpose here is to illustrate the relation of break-even capital cost to the array collector area and to utility buyback rate. A complete list of the assumptions behind this analysis is given in Appendix B. It is seen that high buyback rates yield monotonically increasing returns with array area, whereas medium and low rates show optimum array sizes limited to the 40 to 60-m^2 range. These results are repeated throughout the literature.

The earlier systems are likely to benefit from an environment of high buyback rates. For a collector area of 40-80m^2, the allowable system cost for the Boston residence is between \$150/m^2 and \$190/m^2 (\$1.50/W_p-\$1.90/W_p at 10% array efficiency). As these are 1980

Figure 2

System Breakeven Capital Cost vs. PV Array Area
(1980 Dollars)

Boston
1986 Residence
No Tax Credits



dollars, the figures correlate well with the very early projections of PV allowable cost set back in 1973 ($\$0.50/W_p$ for the PV module alone--1975 dollars).

3.3 Investment Benefits

The purchaser perspective on allowable cost is exemplified in the pro forma financial summaries of Figs. 3-9. These figures portray cash flow sensitivity to three critical parameters: level of solar intensity, level of investment tax credit, and taxation of homeowner electricity revenues. Figure 3 presents the cash streams for a Boston residence with zero tax credit subsidies. This figure depicts an investment of marginal value. Figure 4 shows the same investment, under a simultaneous purchase and sale contract with the utility, where all electricity sold is taxed as ordinary income. Such an arrangement has disastrous consequences for the investment. Most of the worth analyses to date have not assumed homeowners would be taxed on any portion of the energy revenues. In fact, either the homeowner is fully taxed under simultaneous purchase and sale, not taxed at all, or taxed on the basis of excess of net energy. The latter would stipulate that taxes be paid on all net income from the utility, ensuring that optimum PV array sizes do not exceed a capacity that would generate, on average, excess to the average load. Presuming a homeowner must treat as ordinary income all sales in excess of net energy, then it is necessary to determine the net energy time frame. This may be each utility billing period, each tax period, or other. The difference could well be significant in economic terms, depending upon the load profile of the user.

Figures 5 and 6 reveal the effects of income shelter through tax credit subsidies on the federal and combined federal and state level,

Figure 3

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Boston
Project start year:	1982
Annual output:	7020 kWh
System Cost:	$11160.00
Down Payment:	10%
Fed Tax Rate:	35%
State Tax Rate:	5%
Facility life:	20 years
Loan life:	20 years

Project NPV: $658.

Fed tax credit: 0%
State tax credit: 0%

Zero Net Energy Bill
No Tax on Sales to Utility

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	795.	1518.	152.	76.	1261.	-2212.	1104.84	-466.40	-71.56	-1674.3[illegible]	-1012.[illegible]
2	867.		164.	82.	1261.	-640.	1087.63	-466.76	-71.61	-102.62	-54.19
3	946.		177.	89.	1261.	-581.	1068.53	-466.96	-71.64	-47.37	-19.[illegible]
4	1052.		191.	96.	1261.	-516.	1047.33	-466.98	-71.65	22.35	9.[illegible]
5	1126.		207.	103.	1261.	-446.	1023.79	-466.77	-71.62	92.[illegible]	33.[illegible]
6	1223.		223.	112.	1261.	-368.	997.67	-466.30	-71.54	169.73	54.73
7	1339.		241.	120.	1261.	-283.	968.67	-465.53	-71.42	253.54	72.1[illegible]
8	1461.		260.	130.	1261.	-191.	936.48	-464.38	-71.25	344.91	86.[illegible]
9	1594.		281.	141.	1261.	-89.	900.75	-462.80	-71.01	444.52	[illegible]
10	1733.		304.	152.	1261.	22.	861.10	-460.73	-70.69	553.09	107.8[illegible]
11	1896.		328.	164.	1261.	143.	817.08	-458.07	-70.28	671.43	115.46
12	2068.		354.	177.	1261.	276.	768.21	-454.73	-69.77	800.43	121.37
13	2256.		382.	191.	1261.	421.	713.98	-450.62	-69.14	940.97	125.[illegible]
14	2461.		413.	206.	1261.	580.	653.77	-445.60	-68.37	1094.15	129.02
15	2684.		446.	223.	1261.	754.	586.95	-439.56	-67.44	1261.06	131.13
16	2928.		482.	241.	1261.	944.	512.77	-432.33	-66.33	1442.94	132.3[illegible]
17	3194.		520.	260.	1261.	1152.	430.43	-423.74	-65.01	1641.09	132.[illegible]
18	3484.		562.	281.	1261.	1380.	339.04	-413.59	-63.46	1856.98	132.4[illegible]
19	3800.		607.	303.	1261.	1629.	237.60	-401.68	-61.63	2092.15	131.56
20	4145.		655.	328.	1261.	1901.	124.99	-387.75	-59.49	2348.33	130.22

Figure 4

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Boston
Project start year:	1982
Annual output:	7020 kWh
System Cost:	$11160.00
Down Payment:	10%
Fed Tax Rate:	35%
State Tax Rate:	5%
Facility life:	20 years
Loan life:	20 years

Project NPV: $-206[illegible].00

Fed tax credit: 0%
State tax credit: 0%

Taxed on Utility Worth of All PV Electricity

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	795.	1518.	152.	76.	1261.	-2212.	1104.84	-188.13	-28.86	-1995.27	-11[illegible].57
2	867.	0.	164.	82.	1261.	-640.	1087.63	-163.22	-25.04	-451.73	-240.8[illegible]
3	946.		177.	89.	1261.	-581.	1068.55	-135.86	-20.84	-424.22	-199.49
4	1052.		191.	96.	1261.	-516.	1047.33	-105.81	-16.23	-394.23	-163.48
5	1126.		207.	103.	1261.	-446.	1023.79	-72.81	-11.17	-361.55	-13[illegible].21
6	1223		223.	112.	1261.	-368.	997.67	-36.58	-5.61	-325.93	-105.10
7	1339.		241.	120.	1261.	-283.	968.67	3.05	0.49	-286.95	-82.60
8	1461.		[illegible]	[illegible]	1261.	-191.	936.48	44.41	7.20	-242.33	-60.77
9	1594.		281.	141.	1261.	-89.	900.75	89.83	14.57	-193.69	-42.83
10	1733.		304.	152.	1261.	22.	861.10	139.72	22.65	-140.7[illegible]	-27.44
11	1896.		328.	164.	1261.	143.	817.08	194.51	31.54	-82.97	-14.27
12	2068.		354.	177.	1261.	276.	768.21	254.69	41.29	-20.08	-3.04
13	2256.		382.	191.	1261.	421.	713.98	320.78	52.01	48.42	6.48
14	2461.		413.	206.	1261.	580.	653.77	393.37	63.78	123.03	14.51
15	2684.		446.	223.	1261.	754.	586.95	473.09	76.71	204.27	21.2[illegible]
16	2928.		482.	241.	1261.	944.	512.77	560.66	90.90	292.72	26.84
17	3194.		520.	260.	1261.	1152.	430.43	656.84	106.50	389.00	31.46
18	3484.		562.	281.	1261.	1380.	339.04	762.49	123.63	493.81	35.21
19	3800.		607.	303.	1261.	1629.	237.60	878.53	142.44	607.87	38.2[illegible]
20	4145.		655.	328.	1261.	1901.	124.99	1005.99	163.11	731.98	40.59

Figure 5

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	**Boston**		**Project NPV:**	$3357
Project start year:	1982			
Annual output:	7020 kWh		**Fed tax credit:**	40%
System Cost:	$11160.00		**State tax credit:**	0%
Down Payment:	10%			
Fed Tax Rate:	35%			
State Tax Rate:	5%			
Facility life:	20 years			
Loan life:	20 years			

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	795.	1518.	152.	76.	1261.	2252.	1104.84	-466.40	-71.56	2789.70	1686.97
2	867.		164.	82.	1261.	-640.	1087.63	-466.76	-71.61	-101.62	-54.19
3	946.		177.	89.	1261.	-581.	1068.53	-466.96	-71.64	-42.32	-19.90
4	1032.		191.	96.	1261.	-516.	1047.33	-466.98	-71.65	22.35	9.27
5	1126.		207.	103.	1261.	-446 .	1023.79	-466.77	-71.62	92.85	33.96
6	1228.		223.	112.	1261.	-368.	997.67	-466.30	-71.54	169.73	54.73
7	1339.		241.	120.	1261.	-283.	968.67	-465.53	-71.42	253.54	72.10
8	1461.		260.	130.	1261.	-191.	936.48	-464.38	-71.25	344.91	86.49
9	1594.		281.	141.	1261.	-89.	900.75	-462.80	-71.01	444.52	98.30
10	1738.		304.	152.	1261.	22.	861.10	-460.73	-79.69	553.09	107.85
11	1896.		328.	164.	1261.	143.	817.08	-458.07	-70.28	671.43	115.46
12	2068.		354.	177.	1261.	276.	768.21	-454.73	-69.77	800.40	121.37
13	2256.		382.	191.	1261.	421.	713.98	-450.62	-69.14	940.97	125.83
14	2461.		413.	206.	1261.	580.	653.77	-445.60	-68.37	1094.15	129.02
15	2684.		446.	223.	1261.	754.	586.95	-439.56	-67.44	1261.06	131.13
16	2928.		482.	241.	1261.	944.	512.77	-432.33	-66.33	1442.94	132.32
17	3194.		520.	260.	1261.	1152.	430.43	-423.74	-65.01	1641.09	132.70
18	3484.		562.	281.	1261.	1380.	339.04	-413.59	-63.46	1856.98	132.42
19	3800.		607.	303.	1261.	1629.	237.60	-401.68	-61.63	2092.15	131.56
20	4145.		655.	328.	1261.	1901.	124.99	-387.75	-59.49	2348.33	130.22

Figure 6

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Boston		**Project NPV:**	$4279
Project start year:	1982			
Annual output:	7020 kWh		**Fed tax credit:**	**40%**
System Cost:	$11160.00		**State tax credit:**	**35% (after federal)**
Down Payment:	10%			
Fed Tax Rate:	35%			
State Tax Rate:	5%			
Facility life:	20 years			
Loan life:	20 years			

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	795.	1516	152.	76.	1261.	4595.	1104.84	353.86	-71.56	4313.03	2608.15
2	867.		164.	82.	1261.	-640.	1087.63	-466.76	-71.61	-101.62	-54.19
3	946.		177.	89.	1261.	-581.	1068.53	-466.96	-71.64	-42.32	-19.90
4	1032.		191.	96.	1261.	-516.	1047.33	-466.98	-71.65	22.35	9.27
5	1126.		207.	103.	1261.	-466.	1023.79	-466.77	-71.62	92.85	33.96
6	1228.		223.	112.	1261.	-368.	997.67	-466.30	-71.54	169.73	54.73
7	1339.		241.	120.	1261.	-283.	968.67	-465.53	-71.42	253.54	72.10
8	1461.		260.	130.	1261.	-191.	936.48	-464.38	-71.25	344.91	86.49
9	1594.		281.	141.	1261.	-89.	900.75	-462.80	-71.01	444.52	98.30
10	1738.		304.	152.	1261.	22.	861.10	-460.73	-79.69	553.09	107.85
11	1896.		328.	164.	1261.	143.	817.08	-458.07	-70.28	671.43	115.46
12	2068.		354.	177.	1261.	276.	768.21	-454.73	-69.77	800.40	121.37
13	2256.		382.	191.	1261.	421.	713.98	-450.62	-69.14	940.97	125.83
14	2461.		413.	206.	1261.	580.	653.77	-445.60	-68.37	1094.15	129.02
15	2684.		446.	223.	1261.	754.	586.95	-439.56	-67.44	1261.06	131.13
16	2928.		482.	241.	1261.	944.	512.77	-432.33	-66.33	1442.94	132.32
17	3194.		520.	260.	1261.	1152.	430.43	-423.74	-65.01	1641.09	132.70
18	3484.		562.	281.	1261.	1380.	339.04	-413.59	-63.46	1856.98	132.42
19	3800.		607.	303.	1261.	1629.	237.60	-401.68	-61.63	2092.15	131.56
20	4145.		655.	328.	1261.	1901.	124.99	-387.75	-59.49	2348.33	130.22

Figure 7

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Los Angeles		Project NPV:	$4520
Project start year:	1982			
Annual output:	10998 kWh		Fed tax credit:	0%
System Cost:	$11160.00		State tax credit:	0%
Down Payment:	10%			
Fed Tax Rate:	35%			
State Tax Rate:	5%			
Facility life:	20 years			
Loan life:	20 years			

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	1246.	1518.	152.	76.	1261.	-1762.	1104.84	-466.40	-71.56	-1223.76	-740.03
2	1359.		164.	82.	1261.	-149.	1087.63	-466.76	-71.61	389.83	207.88
3	1482.		177.	89.	1261.	-45.	1068.53	-466.96	-71.64	493.75	232.19
4	1617.		191.	96.	1261.	68.	1047.33	-466.98	-71.65	607.09	251.75
5	1763.		207.	103.	1261.	192.	1023.79	-466.77	-71.62	730.69	267.20
6	1924.		223.	112.	1261.	328.	997.67	-466.30	-71.54	865.48	279.09
7	2098.		241.	120.	1261.	476.	968.67	-465.53	-71.42	1012.47	287.91
8	2289.		260.	130.	1261.	637.	936.48	-464.38	-71.25	1172.75	294.08
9	2497.		281.	141.	1261.	814.	900.75	-462.80	-71.01	1347.52	297.98
10	2723.		304.	152.	1261.	1007.	861.10	-460.73	-70.69	1538.08	299.93
11	2970.		328.	164.	1261.	1216.	817.08	-458.07	-70.28	1745.85	300.22
12	3240.		354.	177.	1261.	1448.	768.21	-454.73	-69.77	1972.39	299.09
13	3534.		382.	191.	1261.	1700.	713.98	-450.62	-69.14	2219.37	296.78
14	3855.		413.	206.	1261.	1975.	653.77	-445.60	-68.37	2488.62	293.46
15	4205.		445.	223.	1261.	2275.	586.95	-439.56	-67.44	2782.16	289.31
16	4587.		482.	241.	1261.	2603.	512.77	-432.33	-66.33	3102.14	284.46
17	5004.		520.	260.	1261.	2962.	430.43	-423.74	-65.01	3450.95	279.05
18	5458.		562.	281.	1261.	3354.	339.04	-413.59	-63.46	3831.16	273.19
19	5954.		607.	303.	1261.	3782.	237.60	-401.68	-61.63	4245.59	266.97
20	6494.		655.	328.	1261.	4250.	124.99	-387.75	-59.49	4697.30	260.47

Figure 8

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Los Angeles		Project NPV:	$7220
Project start year:	1982			
Annual output:	10998 kWh		Fed tax credit:	40%
System Cost:	$11160.00		State tax credit:	0%
Down Payment:	10%			
Fed Tax Rate:	35%			
State Tax Rate:	5%			
Facility life:	20 years			
Loan life:	20 years			

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	1246.	1518.	152.	76.	1261.	2702.	1104.84	-466.40	-71.56	3240.24	1959.42
2	1359.		164.	82.	1261.	-149.	1087.63	-455.76	-71.61	389.63	207.88
3	1482.		177.	89.	1261.	-45.	1068.53	-466.96	-71.64	493.75	232.19
4	1617.		191.	96.	1261.	68.	1047.33	-466.98	-71.65	607.09	251.75
5	1763.		207.	103.	1261.	192.	1023.79	-466.77	-71.62	730.69	267.20
6	1924.		223.	112.	1261.	328.	997.67	-466.30	-71.54	865.48	279.09
7	2098.		241.	120.	1261.	476.	968.67	-465.53	-71.42	1012.47	287.91
8	2289		260.	130.	1261.	637.	936.48	-464.38	-71.25	1172.75	294.08
9	2497.		281.	141.	1261.	614.	900.75	-462.80	-71.01	1347.52	297.98
10	2723.		304.	152.	1261.	1007.	861.10	-460.73	-70.69	1538.08	299.93
11	2970.		328.	164.	1261.	1218.	817.08	-458.07	-70.28	1745.85	300.22
12	3240.		354.	177.	1261.	1448.	768.21	-454.73	-69.77	1972.39	299.09
13	3534.		382.	191.	1261.	1700.	713.98	-450.62	-69.14	2219.37	296.78
14	3855.		413.	206.	1261.	1975.	653.77	-445.60	-68.37	2488.62	293.46
15	4205.		446.	223.	1261.	2275.	586.95	-439.56	-67.44	2782.16	289.31
16	4587.		482.	241.	1261.	2603.	512.77	-432.33	-66.33	3102.14	284.46
17	5004.		520.	260.	1261.	2962.	430.43	-423.74	-65.01	3450.95	279.05
18	5458.		562.	281.	1261.	3354.	339.04	-413.59	-63.46	3831.16	273.19
19	5954.		607.	303.	1261.	3782.	237.60	-401.68	-61.63	4245.59	266.97
20	6494.		655.	328.	1261.	4250.	124.99	-387.75	-59.49	4597.30	260.47

Figure 9

Residential Photovoltaic System Cash Flow Analysis

Mortgage Financing

Location:	Los Angeles	Project NPV:	$8667
Project start year:	1982		
Annual output:	10996 kWh	Fed tax credit:	40%
System Cost:	$11160.00	State tax credit:	35% (after federal)
Down Payment:	10%		
Fed Tax Rate:	35%		
State Tax Rate:	5%		
Facility life:	20 years		
Loan life:	20 years		

Year	Elec Sales	Capital Cost	O&M Cost	Insur Cost	Mortgage Payment	Cash Flow Before Taxes	Interest Cost	Fed Taxes	State Taxes	Cash Flow After Taxes	Discounted Cash Flow After Taxes
1	1246.	1518.	152.	76.	1261.	6355.	1104.84	822.58	-71.56	5634.05	3406.93
2	1359.		164.	82.	1261.	-149.	1087.63	-466.76	-71.61	389.83	207.88
3	1482.		177.	89.	1261.	-45.	1068.53	-466.96	-71.64	493.75	232.19
4	1617.		191.	96.	1261.	68.	1047.33	-466.98	-71.65	607.09	251.75
5	1763.		207.	103.	1261.	192.	1023.79	-466.77	-71.62	730.69	267.20
6	1924.		223.	112.	1261.	328.	997.67	-466.30	-71.54	865.48	279.09
7	2098.		241.	120.	1261.	476.	968.67	-465.53	-71.42	1012.47	287.91
8	2289.		260.	130.	1261.	637.	936.48	-464.38	-71.25	1172.75	294.08
9	2497.		281.	141.	1261.	814.	900.75	-462.80	-71.01	1347.52	297.98
10	2723.		304.	152.	1261.	1007	861.10	-460.73	-70.69	1538.08	299.93
11	2970.		328.	164.	1261.	1218.	817.08	-458.07	-70.28	1745.85	300.22
12	3240.		354.	177.	1261.	1448.	768.21	-454.73	-69.77	1972.39	299.09
13	3534.		382.	191.	1261.	1700.	713.98	-450.62	-69.14	2219.37	296.78
14	3855.		413.	206.	1261.	1975.	653.77	-445.60	-68.37	2488.62	293.46
15	4205.		446.	223.	1261.	2275.	586.95	-439.56	-67.44	2782.16	283.31
16	4587.		482.	241.	1261.	2603.	512.77	-432.33	-66.33	3102.14	284.46
17	5004.		520.	260.	1261.	2962.	430.43	-423.74	-65.01	3450.95	279.05
18	5458.		562.	281.	1261.	3354.	339.04	-413.59	-63.46	3831.16	273.19
19	5954.		607.	303.	1261.	3782.	237.60	-401.68	-61.63	4245.59	266.97
20	6494.		655.	328.	1261.	4250.	124.99	-387.75	-59.49	4697.30	260.47

respectively. The impact of this subsidy is enormous. Figures 7, 8 and 9 repeat the cash flow analyses for the conditions of no subsidy, federal tax subsidy, and combined federal and state subsidies for a residence in Los Angeles, where annual solar insolation exceeds that in Boston by over 50%.

These results, when combined with the sensitivity report of Fig. 1, underscore the dependence of PV worth upon three critical, region-specific parameters: solar insolation, local utility rates, and level of tax credit/subsidy. The next section explores the significance of this fact on its regional basis.

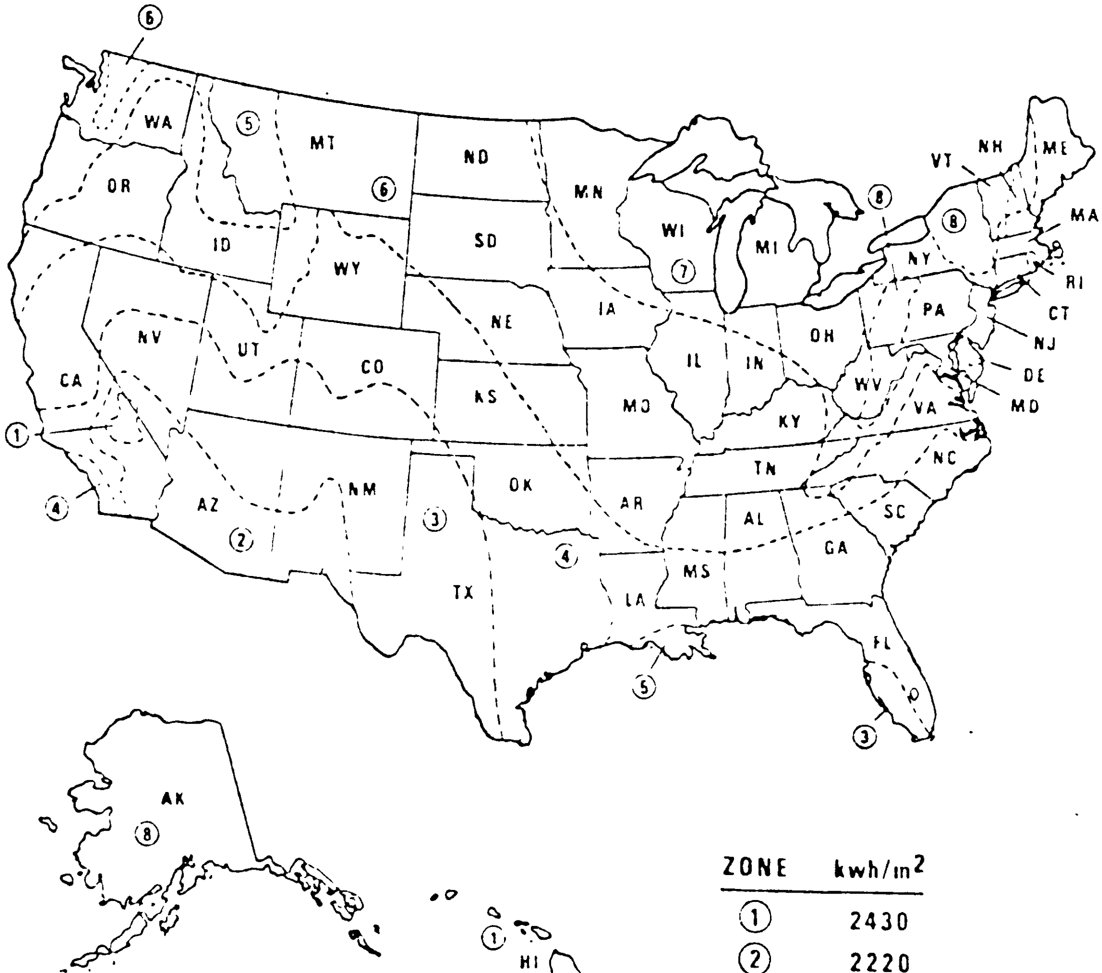
4.0 PV Worth: A U.S. Regional Analysis

It has been shown that PV economics is largely dependent upon specific regional factors: insolation, electricity costs, and local tax credit subsidies (in addition to federal). It is not within the scope of this summary to present a detailed regional PV worth analysis. Such a study in 1981 would be premature simply because electricity costs and legislation of tax credits are too unpredictable. A detailed regional assessment will be appropriate at a point much closer to the break-even year.

A first-order assessment can be useful, however. Figures 10 and 11 utilize regional solar insolation to derive a levelized energy cost under various PV purchase-cost assumptions. The analysis adapts the levelized cost methodology described by Clorfeine (presented in Appendix A) and parameterizes the level of tax credit subsidy. The third major variable, the local electric rate, is supplied by the reader and compared with the values of the zone and tax credit matrix of Fig. 9. Levelized costs well

Figure 10

ANNUAL SOLAR INSOLATION (kwh/m2)



ZONE	kwh/m2
1	2430
2	2220
3	2010
4	1800
5	1590
6	1380
7	1170
8	960

Figure 9

Zone/Subsidy Matrix of PV system Levelized Costs
1980 Dollars
Low Cost (Installed): $150/m^2
High Cost (Installed): $300/m^2
O&M Cost : $50/m^2 year
(limit on tax credits based on 60 m^2 system size)

system efficiency: 10%
buyback rate : 80%
Fixed Charge Rate: 12%

Levelized Cost: ¢/kWh (1980$)

Zone	Annual Insolation kWh/m^2 yr	No Tax Credits Low	No Tax Credits High	Fed ITC = 40%, max 10k Low	Fed ITC = 40%, max 10k High	Fed ITC = 40%, max 10k State ITC = 35% Low	Fed ITC = 40%, max 10k State ITC = 35% High
1	2430	8.2	16.1	5.0	12.6	3.3	8.3
2	2220	9.0	17.7	5.5	13.8	3.6	9.1
3	2080	9.9	19.5	6.0	15.2	4.0	10.0
4	1800	11.1	21.8	6.7	17.0	4.5	11.2
5	1590	12.5	24.7	7.6	19.3	5.1	12.6
6	1380	14.4	28.4	8.8	22.2	5.9	14.6
7	1170	17.0	33.5	10.4	26.2	6.9	17.2
8	960	20.7	40.9	12.6	31.9	8.4	20.9

below current electric rates in a chosen zone with similar tax credit subsidies is reasonable indication of early-on PV penetration.

5.0 Alternative Configurations

Two primary "special" configurations have been investigated as a result of subcontracts to the Photovoltaics Program: PV operation in tandem with electrical storage and PV/T combined collector systems. A third study investigated those issues that distinguish PV retrofit from new construction applications. A summary of the findings of these studies is presented here.

5.1 Photovoltaics and Storage

Two principal studies were contracted to investigate the economics of residential photovoltaics plus storage. The first study was conducted by the author (12) at MIT and examined photovoltaic operation in tandem with a novel concept in stationary flywheel storage. A second study by Caskey and Caskey at SANDIA (7) presents an exhaustive and well-written parametric evaluation of the worth of photovoltaics with batteries. This section will concentrate on a comparison of these two reports.

The primary difference in modeling assumptions between the two studies is that the flywheel analysis simulated a storage device dedicated to the PV array, whereas the battery study examined the feasibility of system storage, allowing for configurations involving no photovoltaics whatsoever. Even so, it is possible to compare the two studies for low buyback rates coupled with flat, or mildly differentiated (peak to base) time-of-use pricing schemes. The studies report similar results under these conditions, where buyback rates from 0 to 50% yield positive optimum storage capacities for the lower storage cost forecasts.

For example, SANDIA reports that for battery costs of $163/kWh, an optimal configuration is that of a battery pack sized at 24 kWh coupled to an 85 m^2 PV array. The cost of such a system is projected at $16000. The flywheel study defines the break-even cost of a similar configuration at $13000, using a 20% investment tax credit. Applying the 20% credit to the $16,000 SANDIA figure yields $12,800, corresponding well with the MIT result.

Specific conclusions drawn by both studies concerning the worth of storage to photovoltaics include the following:

Storage serves the greatest increment in system value at the lower (less than 50%) utility buyback rates (since low buyback rates are not anticipated without significant renewables penetration into the utility grid, storage is not likely to be of near-term interest as packaged with photovoltaics. The utility system itself will serve the function of system storage--MIT study).

For low expected storage costs, the addition of storage increases the size of an optimal PV system.

Due to the latter fact, and also that storage tends to displace energy on utility peak, storage increases the opportunities for displacing imported oil.

Time of use price differentials above 2:1 are required before utility rate structures begin to enhance storage economics.

Greater opportunities exist for cost reduction with battery storage systems as with the stationary flywheel concept.

5.2 <u>Photovoltaic/Thermal Combined Collector Systems</u>

Two major studies were conducted to investigate the suitability of joining photovoltaics with flat-plate solar thermal collector systems, again at MIT (13) and SANDIA (18). Neither study bodes well for combining the collector functions. Basically the combined collectors suffer from inferior operating efficiencies coupled with a mismatch of optimum sizing for the thermal and electrical components.

The MIT study investigated a PV/T liquid collector system set in three alternative northern U.S. locations: Boston, Madison and Omaha. It determined that for specific ranges of total collector area, the costs allowed to combined collectors exceeded those allowed to the separate collectors standing side by side. This range centers around 60 m^2 for Boston and 40 m^2 for Omaha. Outside of this range, one or the other side-by-side system shows higher allowable costs, the lower range dominated by higher proportional thermal component and the higher range looking for a high proportion of PV. This merely says that the thermal component of a separate PV/T system is optimally sized smaller than the electrical component. It also suggests that given further optimizing of the relative PV to T areas for the separate collector system in all ranges of total collector areas, the allowable costs will be slightly above those of the combined collector system.

Will the total costs for a combined collector system be lower than those of separate collector systems? A review of the MIT figures reveals that the difference in allowable cost is not significant, on the order of \$10-\$30/m^2. The costs of installation would probably favor the combined collectors. The combined collector system consists of all the components that the separate configuration requires, but in addition must be equipped with a heat rejection unit for PV cooling in the summer. Experience in the field has shown that overheating is a serious problem for integral mount designs. All costs associated with alleviating this problem must be accounted for on the allowable costs curve. If a stand-off design is used, this eliminates the roof credit. Thus, overheating of integral mount PV may be a point in favor of combined collector systems.

The MIT study recommends that further funding of research and development of liquid collector PV/T (of design similar to that used in their analysis) proceed on the basis that proposals offer promise of developing systems $10-$30/m^2 less costly than an equivalent area of optimally proportioned separate collector systems.

5.3 PV Retrofit

A study was performed by the author in September, 1981 examining the features of a PV retrofit application that distinguish PV economics from installations on newly constructed residences. The results of that analysis are summarized as follows.

While the higher thermal and electric loads of older homes work to increase the value of a PV array relative to a less energy-intensive, newly constructed home, numerous other forces serve to cncrease the financial viability of photovoltaics for the latter. These include more convenient and attractive financing terms, lower costs and enhanced efficiency with architectural integration, and generally lower costs of operation, maintenance, insurance, and system mounting and installation. Also, with larger available rooftop areas the fixed costs are more easily hidden, bringing down the cost per unit of installed PV capacity.

The analysis states that certain attractive financing terms can more than offset the disadvantage borne by the sometimes costly physical constraints associated with PV retrofit. As a result, retrofit applications will probably prove viable when entrepreneurs can package PV systems for the homeowner, both financially and as hardware. Financial packaging may occur through lease arrangments or provision of long term financing. Hardware packaging may occur when installation teams are trained to accommodate alternative roof structures to the ready acceptance of PV arrays using innovative, low-cost support structures. It may also occur when PV systems can be developed in so simple and modular a fashion as to allow for homeowner installation, with sale out of local building supply stores.

6.0 PV Costs: Where Are We?

A study was conducted by Cox (8) examining the costs associated with the installation and operation of complete residential PV systems. A summary of the results of that study is shown in Fig. 12. It appears from this figure that under certain conditions, meeting the 1986 DOE cost targets of $1.60/$W_p$ is possible. However, an investigation conducted through conversations with industry representatives (manufacturers and system designers) led to what is believed to be a more realistic assessment of current and projected costs. These results are shown in Fig. 13. Current estimated module costs compare well with the DOE numbers, although actual costs for a complete, installed system appear roughly $5/$W_p$ greater than the DOE estimate. The gap widens considerably in the coming years. Industry projections show that 1986 DOE cost goals are not met until the early 1990s.

Other findings of the cost-study conducted by Cox include:

1. Wiring costs should be minimized by use of recessed contact weatherproof quick-connectors for interconnecting modules.
2. Installation of the power conditioner should be below target costs.

Figure 12

SILICON SYSTEM COST SUMMARY (1980 $\$/W_p$)

	1986 DOE GOAL	1986 PROJECTED NEW		1986 PROJECTED RETROFIT		1980 STATUS	
ARRAY							
PURCHASE	0.93	0.70	1.08	0.70	1.08	9.00	
INSTALL	0.17	0.27	0.66	0.50	0.81	0.63	0.77
POWER CONDITIONER							
PURCHASE	0.25	0.19	0.98	0.26	1.36	0.40	1.60
INSTALL	0.13	0.04		0.08		0.04	
SYSTEM DESIGN	0.12	0.05		0.10		10.00	
	1.60	1.25	2.75	1.64	3.43	20.7	21.04
OPERATE		0.31	0.40	0.54	0.69	1.14	1.50
MAINTAIN		0.09	0.30	0.09	0.30	0.23	0.27
		1.65	3.45	2.27	4.42	21.44	22.81

	Module Cost	Full System Installed Cost
January, 1982	$\$8\text{-}9/W_p$	$\$25/W_p^{+}$
1985	$6/W_p$	$17/W_p$
1988	$3/W_p$	$10/W_p$**
1991	$1/W_p$	$4/W_p^{++}$

*Conversation with industry representative. These values represent subjective expectations as to the range of prices one may expect given the current direction in PV development.

+Utility interactive system in easily accessible location; Stand-alone battery systems currently (1981) sell for roughly $\$35/W_p$.

**Assumes new administration is elected with favorable subsidy program vis a vis commercialization/tax credits which spur demand.

++Assumes high volume market.

Figure 13

Some Representative Industry Expectations*

(1980 Dollars)

November, 1981

3. Self-cleaning or owner-cleaning of modules will be necessary as professional module cleaning is too expensive.

4. An overall system markup of 30% is compatible with 1986 cost goals while 60% and higher markups are not likely to be seen.

7.0 Critique of the Worth Analysis Effort

There are two issues that should be raised in critique of the PV worth analysis effort. One pertains to analytic detail, the other to program redundancy. The homowner purchase scenario depicted in Section 2.0 reduced all worth studies to date to a simple, two minute back of the envelope evaluation. Of course there is good reason for the more sophisticated analysis. First there is the issue of multimillion dollar funding allocations. Only more sophisticated analyses can determine which system components critically need cost reductions and what alternative configurations might enhance PV worth. On the purchase side, exhaustive research helps define why lease option terms might be more attractive in San Diego and Boston than in Milwaukee. The problem that has arisen in the later analyses is whether too much effort went into modeling detail when other factors were clearly limiting the analysis. Is a 40-parameter, hourly (1 year) PV simulation model justified when the input is National Weather Service massaged data? Should one be concerned with modeling time-varying utility buyback rates when a 10% change in so political a variable as the solar tax credit is five-fold more significant?

There are many inherent limits to projection of PV worth for a 10-20 year time horizon. These should be considered first before establishing the detail of the various models.

Numerous reports have been sponsored by the DOE for the assessment of PV worth. Some of these studies may appear redundant. On the other hand they may provide a necessary cross-check on results. They certainly provide valuable checks so long as the researchers are aware of each others work, and hence communication is important.

8.0 Summary and Conclusions

Two critical perspectives have been addressed by the analyses of residential PV worth. For the researcher and designer, allowable costs have been established. For the homeowner and institutional decision-makers investment figures of merit have been identified. The first allowable cost figure was established in 1973 and set at $\$0.50/W_p$ (1975 \$) for the PV module component alone. This is very nearly the median of allowable costs projected from todays more refined analyses. These show allowable installed system costs ranging from $\$1.50/W_p$ to $\$4.00/W_p$ (1980 \$), depending upon certain critical variables. The more critical variables are few, and are locally defined: level of solar insolation, local utility rates, and locally available tax credit/subsidies (in addition to the federal). Other parameters that are critical, but more predictable (and hence embedded in the analysis) are the PV array efficiency, utility buyback rate, utility rate escalation, and homeowner discount rate.

One concern that appears to impact heavily on residential PV economics, and that has not been treated widely in the literature, is whether homeowners will be taxed at their ordinary income tax rate for electricity sold to the utility. If so, will it be for all PV electricity produced (requiring 2 meters, as in simultaneous purchase and sale), all PV energy in excess of instantaneous load, or on the basis of net energy sold over some pre-established time period (utility billing period, tax period, etc.). Assumptions here are critical in the final analysis.

With regards to special applications, the simplest are the most surviving. With higher anticipated utility buyback rates, batteries do nothing to enhance the value of photovoltaics. Photovoltaics attached to thermal collectors are suboptimal compared to side-by-side systems. New construction applications for a simple utility interconnect system offer cost savings over typical retrofit installations.

In matching industry expected costs with the latest assessment of investor allowable costs, one suspects that the residential market will begin to accelerate around 1990. It will happen first in those areas of high solar insolation, high utility electric rates and significant investment incentives (tax credits or others). An analysis of current trends shows that these break-even years for residential photovoltaics should be welcomed by a ready institutional climate.

References

1. Bleiden, H.R., "A National Plan for Photovoltaic Conversion of Solar Energy," in Workshop Proceedings Photovoltaic Conversion of Solar Energy for Terrestrial Applications, Vol 1, October 23-25, 1973, Cherry Hill, NJ, NSF-RA-N-74-013.

2. Low Cost Silicon Solar Array Project, "Division 31 Support Plan for FY77 Project Analysis and Integration Activities", Jet Propulsion Laboratory, California Institute of Technology, Pasadena, CA, April25, 1977.

3. Carpenter, Paul R. and Tabors, Richard D., "A Uniform Economic Valuation Methodology for Solar Photovoltaic Applications Competing in a Utility Environment", MIT Energy Laboratory Report No. MIT-EL-78-010, June, 1978.

4. Solar Times, "Luz International to Sell Solar Solar Steam to Three Large U.S. Textile Mills", article on page 1, Volume 3, Number 10, October, 1981.

5. Merrill Lynch Pierce Fenner & Smith, Inc. "The Outlook for Alternative Generation Financial Techniques in Public Power", Fixed Income Research Division, September, 1981, page 3.

6. Ibid, p. 2.

7. Dinwoodie, T.L. and Kavanaugh, J.P.,"Cost Goals for a Residential Photovoltaic/Thermal Liquid Collector System Set in Three Northern Locations", MIT Energy Lab Report No. MIT-EL-80-028, October, 1980.

Appendix A: Summary of Evaluation Methods

Several methods have been developed for analysis of PV worth under the unique conditions characteristic of a solar technology. These methods range in both sophistication and purpose. The earlier methods address simple cost break-even objectives while the latter simulate the cash flows requisite for investor decision analysis.

Several of these methods are listed as follows:

Method	Origination	Purpose	Reference
Break-even Analysis	Carpenter & Tabors MIT Energy Lab	Cost Goals	6
Utility Method of Levelized Cost Comparison	Clorfeine, DOE	Simplified Lev Cost	3
Mortgage Finance, Cash Flow Analysis	Dinwoodie, MIT Energy Lab	Cost Goals; Cash Flow Investment Analysis	15
Nomograph	Bawa, Texas Instruments	Nomograph for Engineering System Sizing	1

Figures A-1 through A-4 provide a closer look at these methods.

Figure A-1: Carpenter & Tabors/Uniform Methodology*
(ref. 6)

SUGGESTED USER-OWNED ECONOMIC VALUATION METHODOLOGY

It is important at the outset to distinguish between the methodology in general and the particular way in which it will be configured to examine user-owned photovoltaics. In general, the methodology defines two numbers. The first is called the "break-even" capital cost and is calculated by finding the difference between the user's electricity bills with and without the device according to the following formula:

$$BECC = \frac{\left[\sum_{J=1}^{n} \frac{\sum_{i=1}^{8760}\left(X_{Oi} - X_{Di}\right) \cdot EFACT(J) \cdot DFACT(J)}{(1+\rho)^{J} \cdot ACOL}\right] - \left(\frac{FIXEDC}{ACOL} + VARC\right)}{\eta_{system} \cdot 1000\ w/m^2}$$

Where:

BECC	= Break-even capital cost in \$/W(peak) system*
oi	= Utility bill for hour i without device in \$
Di	= Utility bill for hour i with device in \$
EFACT(J)	= weighted fuel price escalation factor for year J based on fuel price component of rate structure
DFACT(J)	= benefits degradation factor for year J based on module degradation
	= discount rate appropriate to user
n.	= lifetime of device
ACOL	= collector area in m^2
FIXEDC	= fixed subsystem costs (including installation, power conditioning, lightning protection, etc.) in \$
VARC	= variable subsystem costs (including installation = O&M, markups, insurance, taxes, etc.) in \$/m^2
η system	= system efficiency.*

BECC can be considered an economic indifference value - that price at which the user would be economically indifferent between having and not having the device. This formula contains a number of features. First, the valuation which is the difference in the utility bills to the user, is determined by the utility rate structure and whatever the utility is willing to pay for surplus energy supplied by the owner to the grid. If the rate structure reflects the load demand on the utility (as under peak-load pricing), then this valuation explicitly values the "quality" component of the energy supplied by the device. Second, it is a figure defined in dollar units. This automatically adjusts for the scale of the device and allows direct comparison between two devices in the same application.

---

* To calculate \$/w(peak) module, the traditional value used by the Photovoltaic Program η module should be substituted for η system in the denominator of the equation.

Figure A-2: Clorfeine/Levelized Energy Cost (ref. 8)

$$Q = \frac{CR + M}{n\ U\ H} \times 10^4$$

Q = homeowner's annual amortized payments for the PV system (¢/KWH)

C = THE TOTAL INSTALLED SYTEM COST ($\$/M^2$) WHICH INCLUDES MATERIALS, PROCESSING, LABOR, AND BALANCE-OF-SYSTEM COSTS

R = FIXED CHARGE RATE FOR HOMEOWNERS, WHICH TAKES INTO ACCOUNT THE EFFECTIVE PRINCIPAL, INTEREST, TAXES AND INSURANCE CHARGES.

M = YEARLY OPERATION AND MAINTENANCE CHARGES ($\$/M^2$ year)

n = SYSTEM ENERGY CONVERSION EFFICIENCY

U = ENERGY UTILIZATION (%) = [1 - F(1-S)] x 100.

F = FRACTION OF ENERGY OUT OF PHASE, WHICH IS TYPICALLY ONE-THIRD

S = UTILITY SELLBACK RATE

H = AVERAGE HOURS PER YEAR OF 1 KW/M^2 INSOLATION.

Figure A-3: Mortgage Cash Flow (ref.15)

Mortgage Finance Method

$$NB = \sum_{t=1}^{L} \frac{e^{y-yb} \cdot \tau_j^{y-yb} \cdot B_{tj} - e^{y-yb} \cdot OM_t + G_t - T_t}{(1+r)^t \cdot e^{y-yb}}$$

$$- \beta \cdot I \cdot D - \sum_{t=1}^{\Gamma} \frac{P_t - (1 - TR_t)\, F_t}{(1+r)^t \cdot e^{y-yb}}$$

where,

NB = net benefits to accrue to the project over its operating life

e^{y-yb} = general inflation multiplier computed for the current calendar year y with respect to some base year yb.

β = capital escalator computed for the construction year with respect to some base year.

τ_j^{y-yb} = real price escalator applied to displaced conventional energy j (different rates applied to electricity, oil, gas, etc.) during the current calendar year y with respect to some base year y_b

B_{tj} = returns to the project in year t in terms of the value of displacing conventional energy of type j.

D = percent down payment/100.

G_t = investment tax credit allowed in year t

I = initial capital cost

j = denotes type of energy diplaced (electricity, gas, oil)

Γ = mortgage life

L = project life

OM_t = annual (in year t) operating and maintenance costs including insurance costs.

r = homeowners discount rate

t = project year

T_t = sum of taxes in year t

TR_t = homeowner's tax rate in year t

F_t = mortgage interest charge in year t computed as

$F_t = A - P_t$, where;

A = annual mortgage payment, given by

$A = I \cdot (1 - D) \cdot (i/[1 - 1/(1 + i))N])$

i = annual mortgage rate

P_t = payment required on the balance of principle in year t, from

$P_t = i \cdot BAL_t$, where

$BAL_t = A\,[1 - 1/\,(1 + i)^{N-t+1}]\,/i$

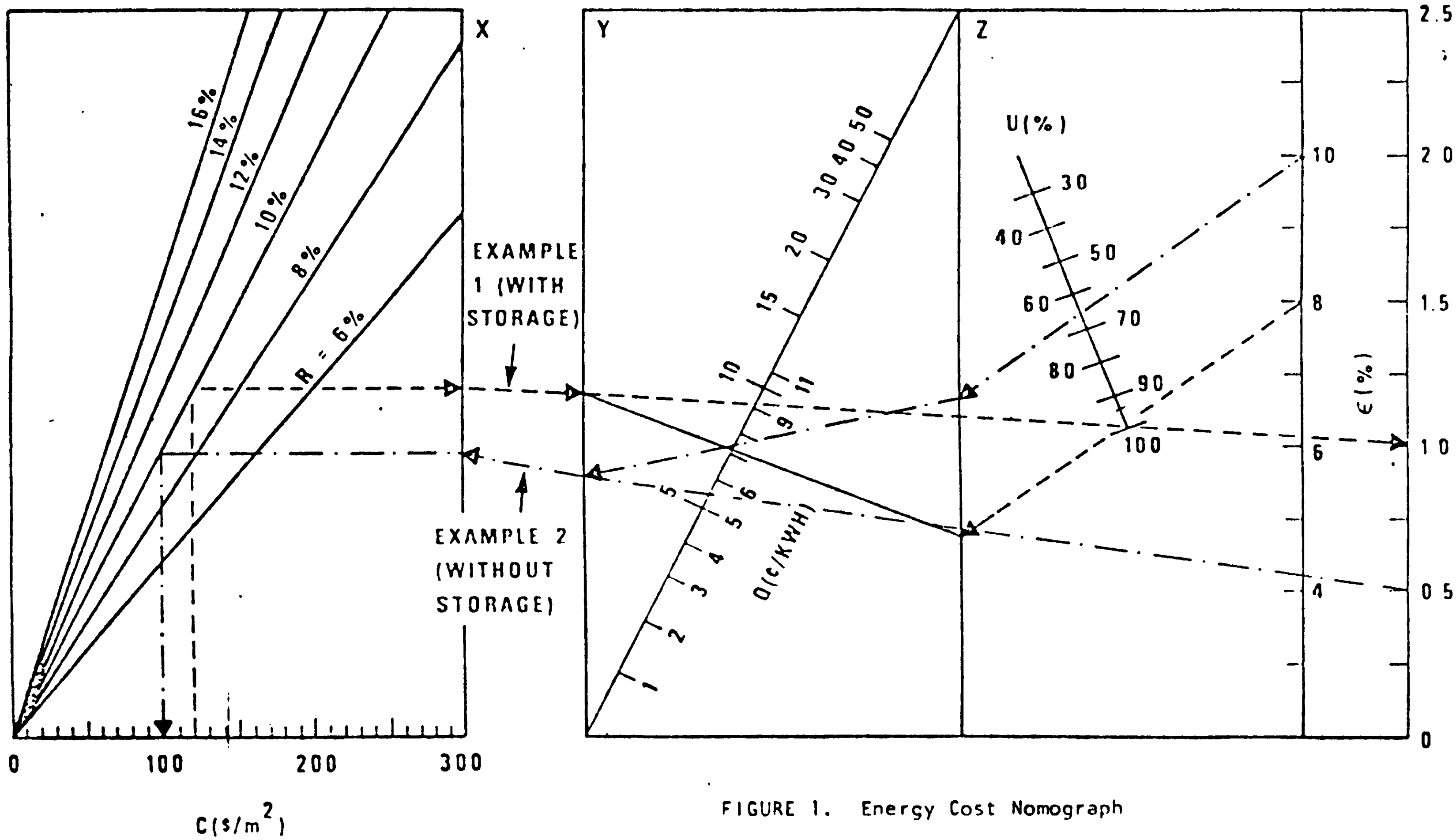


FIGURE 1. Energy Cost Nomograph

Q = Cost of Energy (¢/KwH)
C = Installed Cost ($/m^2)
R = Fixed Charge (%)
M = Annual Maintenance ($/m^2 year)
ε = System Efficiency (%)
U = Energy Utilization (%)

Figure A-4: Nomograph Method of System Sizing
(ref. 1)

Appendix 3: Recent Analytic Assumptions

Figure B-1

System Component Specifications

Glass thickness (cm)	.32
encapsulant thickness	.15
outermost substrate thickness (cm)	.10
conductivity of glass (w/cm°C)	.0105
conductivity of encapsulent (w/cm°C)	.00173
conductivity of substrate (W/cm°C)	.01
$\tau\alpha$ product of cell	.8
$\tau\alpha$ product between cells	.75
emissivity of glass	.83
emissivity of back surface	.9
packing factor (total cell area/gross cell area	.90
IR absorptivity of glass	.99
IR absorptivity of back surface	.9
visible absaorptivity of roof	.6
IR absorptivity of roof	.903
emissivity of roof	.903
reference cell efficiency	.135
Eff. charge coefficient	.0045
reference temperature for ref cell efficiency (°C)	28.
mounting angle from horizontal	latitude + 5°

Figure B-2

Base Case
Residential Electricity Rates by Region*
(Based on Average 600 kwh/month Usage)

Boston

Fixed Charge	$1.17/month
per kwh/charge	3.95¢/kwh
fuel adjustment	3.905¢/kwh
	7.86¢/kwh

Madison

Fixed charge	$2.50/month
per kwh/charge	4.14¢/kwh
fuel adjustment	$ .52¢/kwh
	4.66¢/kwh

Omaha

Fixed charge	$3.95/month
per kwh/charge	3.64¢/kwh
fuel adjustment	.208¢/kwh
	$3.85¢/kwh

* Source: Correspondence with the electric utility in each respective region

Figure B-3

Base Case Market/Financial
Parameters and Annualized Costs

Market Parameters

Escalation in Home Heating Oil Prices (real)	2%/year
Escalation in Gas Prices (real)	2%/year
Escalation in Electricity Prices (real)	1%/year
General Inflation Rate	12% in 1980, declining linearly to 6% in 1986, 6%/year thereafter
Utility Buyback Rate	.80
Electricity Rates (1980 Boston)	
Fixed Charge	\$1.17/month
kWh Charge	3.95 ¢/kWh
Fuel Adjustment	3.905 ¢/kWh
Total	7.86 ¢/kWh

Finance Parameters

System Installation Date	1986
System Lifetime	20 years
Homeowner Discount Rate (real)	5%
Homeowner Tax Rate	35%
Mortgage interest rate (real)	3%
Down payment	10%
Investment tax credit	0
Property taxes	0

Annualized Costs

Cleaning and Inspection	(Annual Cost)
PV-only system*	\$25 + \$1.00/m^2
Maintenance	(Present value at 5% discounting)
PV-only System	\$13.00/m^2

Appendix C: Summary of Reports

Bawa, M.S. "Photovoltaic Energy Cost Nomograph," Texas Instruments, Incorporated, Dallas, TX, 1981.

Bottaro, Drew, et.al. "Modeling Photovoltaic Worth: A Discussion of the Issues and an Analysis of the Models," MIT Energy Lab Report, MIT-EL-80XXX, Forthcoming.

Buerger, E.J., et.al. "Regional Conceptual Design and Analsis Studies for Residential Photovoltaic Systems," Technical Volume II. General Electric.

Burns, William Allen, "A Model for Residential Demand of Electric Appliances," Undergraduate Thesis, Department of Urban Studies and Planning, MIT, Cambridge, MA, May, 1980.

Burt Hill Kosnar Rittleman, "Operation and Maintenance Cost Data for Residential PV Modules/Panels", 1980 DOE Report #DOE/JPL/955614-80/1.

Carpenter, Paul R. and Tabors, Richard D., "A Uniform Economic Valuation Methodology for Solar Photovoltaic Applications Competing in a Utility Environment," MIT Energy Laboratory Report No. MIT-EL 78-010, June 1978.

Caskey, David L., et.al. "Parametric Analysis of Residential Grid-Connected Photovoltaic Systems With Storage," SANDIA Lab Report No. SAND79-2331, March, 1980.

Clorfeine, A.S., "Economic Feasibility of Photovoltaic Energy Systems," presented at the Fourteenth IEEE Photovoltaic Specialists Conference, 1980.

Cox, C.H. III, "Residential Photovoltaic System Costs," MIT Lincoln Laboratory, Report No. DOE/ET/20279-96. January, 1980.

Davis, R.B., et.al. "Major Issues Impacting the Financial Viability of Residential Photovoltaic Systems," Proceedings, IASTED Conference, May 20-22, 1981, San Francisco. CA

Davis, R.B., et.al. "The Effects of Ownership Options, Government Policies, and Operations Alternatives on the Economic Viability of Residential Photovoltaic Systems," Proceedings, Second International Miami Conference on Alternative Energy Sources, December 10-13, 1979, Miami Beach, FL.

Dinwoodie, T.L., "Flywheel Storage for Photovoltaics: An Economic Evaluation of Two Applications," MIT Energy Laboratory Working Paper, MIT-EL-80-002, February, 1980.

Dinwoodie, T.L. and Kavanaugh, J.P., "Cost Goals for a Residential Photovoltaic/Thermal Liquid Collector System Set in Three Northern Locations," MIT Energy Laboratory Report No. MIT-EL-80-028, October 1980.

Dinwoodie, T.L. and Cox, A.J., "The Impact on Photovoltaic Worth of Utility Rate Reform and of Specific Market, Financial, and Policy Variables," MIT Energy Laboratory Report No. MIT-EL-80-025, September 1980.

Dinwoodie, T.L. "OESYS, A Simulation Tool for Non-Conventional Energy Applications Analysis; Theoretical and Operations Description With User Documentation," MIT Energy Laboratory Report No. MIT-EL 80- .

General Electric Space Division, "Applied Research on Energy Storage and Conversion for Photovoltaic and Wind Energy Systems," Final Report, Volume I: Study Summary and Concept Screening and Volume II: Photovoltaic Systems with Energy Storage, January 1978.

General Electric Space Division, "Regional Conceptual Design and Analysis Studies for Residential Photovoltaic Systems," Volume I: Executive Summary, January 1979.

Hoover, E.R. "PV/T Combined Collector Study," In a memo addressed to D.G. Schueler, SANDIA Laboratories, February 25, 1980.

Kasper, J.V.V., et.al. "The Effects of Alternative Utility Rate Structures on the Economic Viability of Small Power Production, A Residential Photovoltaic Example," Paper presented at the Annual Meeting of the American Section of the International Solar Energy Society, June, 1980, Phoenix, AZ.

Moite, S.M. et.al. "Simulation of a Hybrid Solar Photovoltaic/Solar Thermal Electric Power System," presented at the Fourteenth IEEE Photovoltaic Specialists Conference, 1980.

Russell, Miles C. "Solar Photovoltaic/Thermal Residential Systems," Report Number COO-4577-9, MIT Lincoln Laboratory, December 28, 1979.

Tabors, R.D., "Solar Economics (Whose?)," paper presented at the International Association of Energy Economist, Toronto, Canada, June 1981.

Chapter 3

The Economics of the Photovoltaic-Utility Interaction

Alan J. Cox

Susan Finger

Richard D. Tabors

1.0 Introduction

The economic potential of photovoltaics will depend upon either the availability of inexpensive electricity storage or the existence of advantageous arrangements for the interconnection of individually-owned systems with electric utility grids. These interconnection arrangements would include prices for both the purchase of power by the photovoltaic owner (selling prices) and prices for the purchase by the utility of excess solar electricity (buy-back prices). If selling rates to photovoltaic-owning customers (P_e) do not differ from rates to other customers and the buy-back rate is a high proportion of the selling rate (proportion β), then grid-interconnected systems will generally have an economic advantage over stand-alone, storage-augmented systems.* The elimination of storage requirements will reduce the overall cost of the photovoltaic systems that an individual might buy, improving their economic viability substantially.

The proportion, β, and the price, P_e, will be determined by the characteristics of the photovoltaic systems, of the electric utility and of the regulatory environment. For instance, if solar electricity helps to reduce peak utility production and is acceptable, its value to the

*For a discussion of the legal and institutional issues associated with the Public Utilities Regulatory Policy Act (PURPA) P.L. 95-617, specifically Sections 210 and 210a, see Chapter 6.

utility is high. If, in addition, the regulatory authority imposed buy-back rates based upon a utility's highest costs of electricity production while selling rates were still based upon average costs, ß may actually be greater than one. If, on the other hand, photovoltaic production in a given location is very erratic and its purchase by a utility decreases the utilization rate of the utility's capital, then P_e will be high and ß low. If the quality of the solar electricity were poor, in terms of such engineering concerns as wave form, reactive versus real power or frequency control, then ß should, again be low.

The economic effect of photovoltaics on the operation and finances of an electric utility can be measured. This chapter describes the economic impact on a utility of distributed power systems such as photovoltaics. These systems range from the conventional, such as cogeneration, to the renewable, including wind and solar. They can be characterized, firstly, by the fact that their output cannot be controlled by the central utility. They are nondispatchable; solar, for instance, is only available when the sun shines and cogenerated electricity is available only when process steam demands are sufficiently high. They are also distinguished by having very low operating costs, certainly lower than conventional generators.

The evaluation of distributed power presented here will be entirely economic. We will not concern ourselves with the quality of the electricity fed back into the grid by a photovoltaic producer. We merely assume that any solar electricity production that is above that required by the individual owner can be fed into the grid in a form that does not adversely effect the quality of electricity to other customers.[1] Instead we focus upon the effect of photovoltaics on the utilites' load characteristics, their capital requirements and, ultimately, their financial situation. This leads to the estimation of appropriate selling and buy-back prices for electricity under both a regulated and a deregulated situation. Since regulation as it is now practiced is likely to result in a schedule of prices that does not reflect the true costs and benefits of distributed power systems, some attention will be paid to the divergence between regulated prices and prices that reflect the real economic costs of producing electricity.

This chapter reviews some issues in the economics and regulation of electric utilities. It then describes a series of models that estimate the impact of significant amounts of photovoltaics on the operation of the utility, both in the long run and the short run. Using some regionally typical utilities as examples, selling and buyback prices are estimated. Prices estimated under various assumptions about the regulatory environment are used in the following section to measure the economic viability of photovoltaics under different scenarios. This comparison will give an idea of the consequences of the regulatory environment to the possible impact of photovoltaics.

2.0 Operation, Regulation and Economics of Electric Utilities

The primary problem faced by electric utilities is that they face a demand for their product that varies through time. In addition there is

---

[1]For a general discussion of the problems involved in utility interaction, see Tabors and White (1982). A technical discussion is provided in Landsman (1981).

no inexpensive way to store that product. The variation in demand has a daily and an annual cycle, with the peak of the daily cycle generally coming in the mid-afternoon and the peak of the yearly cycle coming in the summer for nearly all U.S. utilities. Furthermore, the demand for electricity tends to increase from year to year.

To meet this pattern of demand the firm's management has available a stock of plants that consume fuel of varying costs at varying levels of efficiency, and which can be expected to produce electricity with varying levels of reliability. In addition, the average cost of generating electricity can be altered by the construction of new plants whose capital costs generally tend to vary inversely with their operating costs.

The object of utility management is to schedule the operation (and maintenance) of these plants in such a way that the cyclical demand is met at the lowest possible cost. Furthermore, the utility must choose from the range of possible technologies to build new plants to meet future levels of demand at the lowest possible cost.

The problem for regulators, in simplest terms, is to ensure that the utility receives enough revenue from its sales of electricity to recover all of its operating costs, all its costs of debt and, additionally, to receive a "reasonable rate of return" on its investments.

Regulation has been necessary to keep the utilities from taking advantage of their monopoly status and earning excessive profits. Monopolies were granted for electric utilites because electricity could be produced most cheaply by a single large utility able to build large plants to meet base loads, a variety of smaller plants to meet cyclical loads, and to operate a single distribution system. As long as costs continue to decline with increases in annual production, then a "natural monopoly" will supply electricity at a lower cost than a group of competitive firms. A natural monopoly will also exist even if costs are increasing with supply as long as the cost of new competitors' generating plants will be higher than those that the monopoly utility could build.[2]

However, regulating prices to ensure that the utility receives enough revenue so that the firm breaks even will not, in general, ensure that the economically optimal prices are set. Economically optimal prices will not be set if the costs are, in fact, increasing with increases in annual production. This may be the situation today. New generating plants probably cost utilities more, per unit of capacity, than the average cost of previous investments. That being the case, the average cost of electricity (or the break-even cost) is lower than the cost of production from the addition to capacity. If price is set equal to average cost, as regulators attempt to do, then the price will be less than the costs of production from a new unit. However, economic theory rigorously proves, and intuition should tell us, that the price of electricity to all customers should equal the cost of electricity from that additional unit. Each customer should pay the cost of producing one more kilowatt-hour of electricity, or he should benefit by that amount if he reduces his consumption by one kilowatt-hour.

The same argument can be made in the hour-to-hour operation of the utility. The utility minimizes cost by producing electricity from the most efficient plants (generally the most expensive to construct) and meets increases in demand with progressively less efficient plants. The costs (or benefits) of meeting increases in demand (or of being able to

---

[2]See R.L. Gordon (1981), p. 2-31.

reduce production due to a decrease in demand) has nothing to do with some average of the cost of electricity from all the hydro sites, nuclear facilities and some expensive oil plant. The cost of meeting this increase in demand is the cost of producing electricity from the oil plant, referred to as the short-run marginal cost. If electricity from the oil plant costs $0.20 per kilowatt-hour, then the value of somebody's cutting back of demand by a kilowatt-hour is $0.20. However, when prices are estimated to allow total costs to be just recovered, then prices will be equal to the average costs of all units producing electricity, some of which may have a fuel cost of zero (as in hydro) or a very low fuel cost (as in nuclear).

These concerns are important in the economic viability of photovoltaics. As we shall see, photovoltaic electricity generally reduces peak consumption of electricity (when the marginal cost is high), and can displace some of a utility's expensive capacity expansion requirements. The value of this production can, therefore, be high. But the price of electricity to the consumer under today's break-even regulation does not reflect the marginal value of this electricity, and the incentive to build a distributed energy system is thus reduced.

Furthermore, the rates of return that utilities have been allowed in the past few years have not even been high enough to give utilities an adequate return on their investment, resulting in low ratios of market value to book value in stocks and poor ratings of bonds. The revenue that regulators allow utilities to collect are also held low by using cost figures of an earlier "test year," when these costs may have been lower. Problems also arise when utilities have large amounts of capital tied up in expensive plants that are not allowed in the calculation of required revenue. Thus, the price of electricity may not even be high enough to cover the average cost (or break-even cost) of producing electricity.

Electric utility deregulation of the sort that would allow prices to reflect the marginal cost of electricity is far behind that of oil or even natural gas. The only piece of legislation that significantly reforms the price structure of electricity is the federal Public Utility Regulatory Policy Act (PURPA) PL 95-617 of 1978, specifically sections 210 and 210a. These sections set out the criteria under which utilities will buy electricity from distributed owners. The act states that all utilities must purchase any electricity offered to them by a "Qualifying Facility," and that the buy-back rate will be non-discriminatory, in the public interest and be just and reasonable to all customers. The selling price of electricity to the distributed systems must not include back-up surcharges (in case of a Qualifying Facility's temporary break-down or lack of availability) unless such back-up is shown to be necessary and is imposing an additional cost on the utility.

The phrase "just and reasonable to all customers of the utility" is intended to ensure that the cost of electricity to other customers does not increase as a result of the rates paid to the qualifying facilities. The Act reinforces this protection by stating that buyback rates will be no <u>greater</u> than the incremental cost of electricity to the utility. Since the "incremental cost" is defined in what can simply be described as the long run marginal cost of electricity,[3], any buyback rate lower

---

[3]The Conference Report states that regulators "... should [in estiamting the incremental cost] look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reaosn of suppy to the utility at that time of power from the cogenerator or small power producer."

than the incremental cost will be a net savings to utility, savings which will be passed on to other customers.

However, the rules promulgated by the Federal Energy Regulatory Commission (FERC) under Section 210 make it clear that the price offered for buyback electricity can be no less than the incremental cost. FERC's ruling is that incremental buyback rates are the only ones that satisfy the requirement that rates encourage development of alternate sources and are also just and reasonable to all consumers, non-discriminatory and in the public interest. Yet, while the rate paid for buyback electricity should be the marginal cost of electricity, the language of the Conference Report on PURPA indicates that Congress expects electricity selling rates (i.e., for utility to consumer sales) to be estimated on the traditional basis of an allowed rate of return plus fuel and operating costs.

Methodology

The system for estimating the worth of photovoltaic systems that is presented in this chapter has three elements. The first of these is an appraisal of the effect of photovoltaics on the day-to-day electric utility's operations and on its long-range planning. From this it is necessary to estimate two sets of prices, the first being prices derived from current regulatory guidelines, the second being prices that reflect the true economic costs of producing electricity and the true economic benefits of distributed production.

These two sets of rates can be used to estimate the profitability of an investment in photovoltaics under the two pricing regimes using the DOE photovoltaic goals as estimates of investment costs. The difference in the profitabilities based upon the two pricing criteria will give us some measure of the individual losses (or, possibly, gains) that would result from the current regulatory situation. Regulated prices could result, for instance, in losses for the photovoltaic investor while economically efficient prices resulted in profits. In that case, failure to reform electricity prices would result in the potential photovoltaic market being virtually eliminated, even though they could provide electricity more cheaply than the utilities marginal plants.

Figure III.1 is a flow diagram of the processes involved in this assessment. At the heart of the assessment is a production costing model which contains information on the operating characteristics of all the generating stations that the utility owns. The hourly demand that the utility must meet is fed to this model and it estimates the lowest operating cost at which the electricity could be produced. These costs are passed on to a rate setting routine which calculates the utility's capital costs and adds that to the operating costs. The average price per kilowatt-hour is then transmitted to a model of a private photovoltaic user which estimates the profits (or losses) that would result from an investment in photovoltaics. The profitability estimates take into account investment costs, financing costs, the value of reducing electricity purchases from the utility and the value of sales of surplus electricity to the utility.

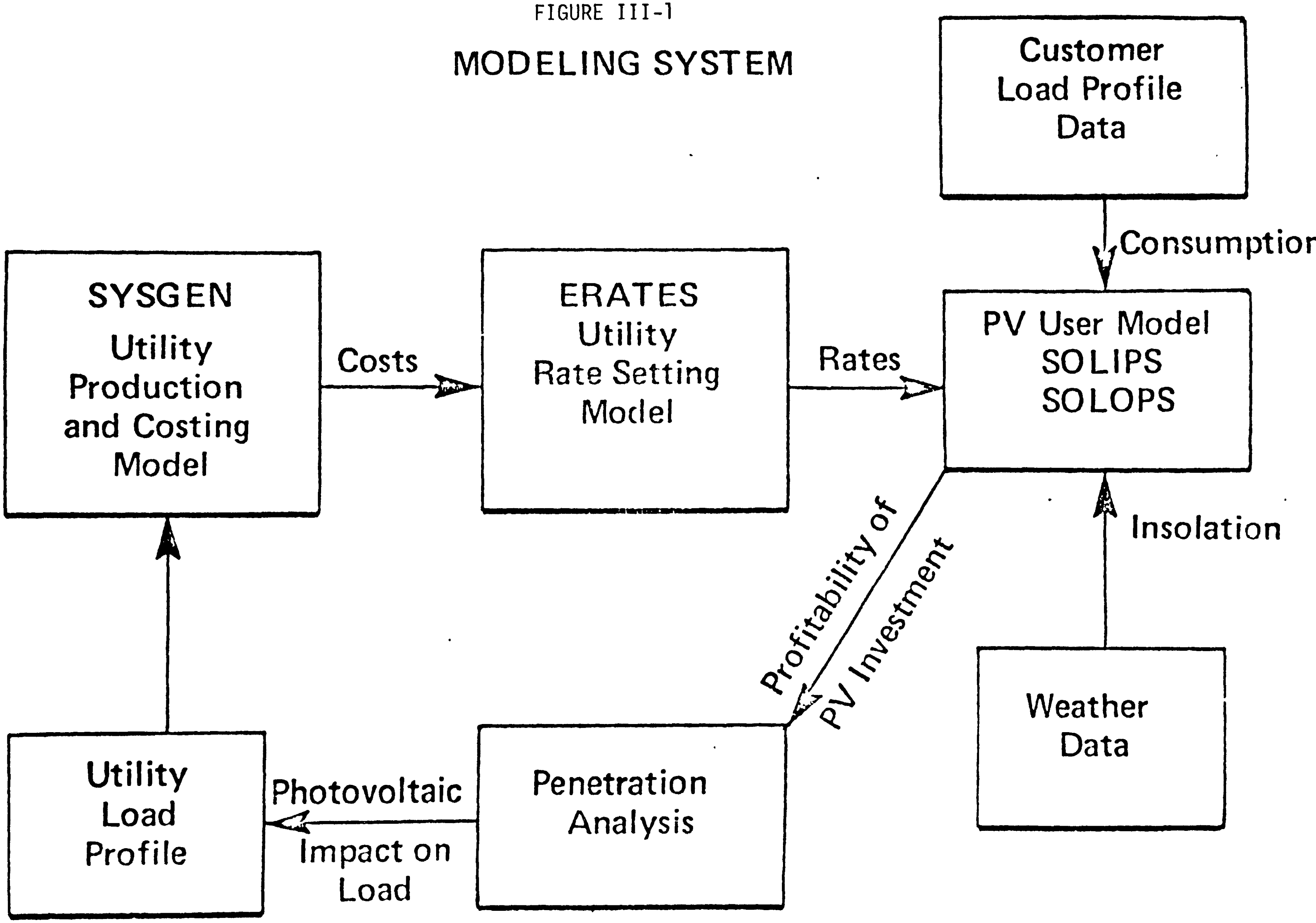
Measuring the effect of photovoltaics on the operation of the utility is initiated from the distributed power model, which alters the utility's recorded demand for electricity by the amount predicted to come from photovoltaics.

The Demand for Electricity

The demand for electricity is represented by a load duration curve

FIGURE III-1

MODELING SYSTEM



which is a probabilistic description of the hour-by-hour demand of the type shown in Figure III.2(c). The curve in III.2(c) merely shows the probability of observing a certain level of demand. For instance, a load greater than or equal to X* Megawatts will be observed P* percent of the year. The load duration curve is derived from III.2(a), which is the hour-by-hour observations of a utility's annual demand. These load observations are arranged from largest to smallest to provide Figure III.2(b). For any number of hours (read off the horizontal axis) the load was greater than or equal to the level indicated by the curve. The observation for 8760 tells us the minimum load observed for the whole year. Figure III.2(c) is created by merely converting the number of hours to the proportion of hours and then tilting the figure along a forty-five degree line running from the origin.

Estimating Annual Utility Operating Costs

Electric power systems are operated with the goal of meeting the electric demand at minimum cost. For a fixed set of generators, the dispatch strategy that results in the minimum oeprating cost is to use the generators in order of increasing marginal cost. In practice this strategy may be modified to account for operating constraints such as spinning reserve requirements, high startup or shutdown costs and transmission constraints. The final ranking of generators is called the merit order or the economic loading order.

The operation of the power system can be modeled by plotting the capacity of the generators, in merit order, along the vertical axis of the customer demand curve as shown in Figure III.3. The demand level at which a unit starts to generate is called its loading point. The energy that a unit generates is the area under the customer demand curve between

FIGURE III-2

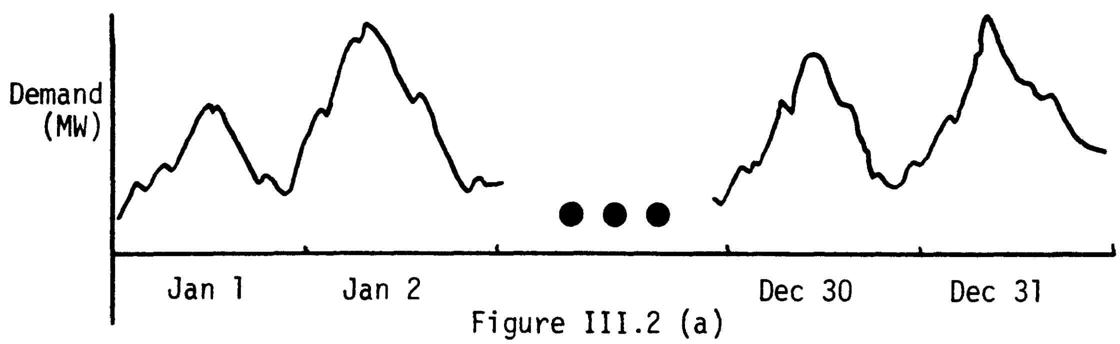


Figure III.2 (a)

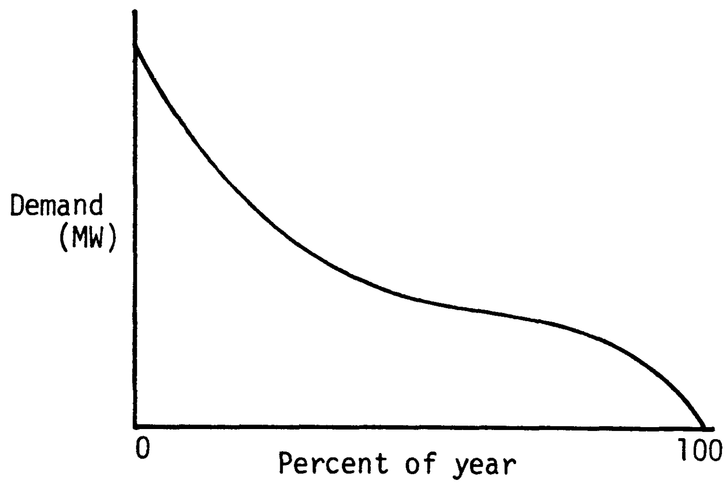


Figure III.2(b)

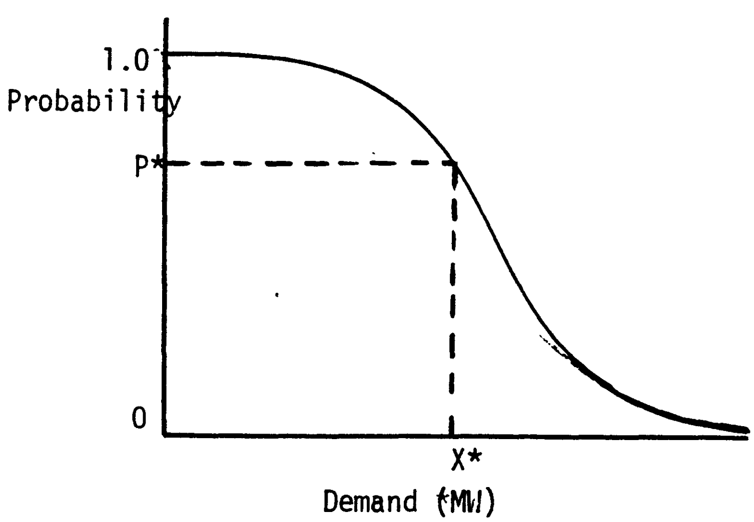
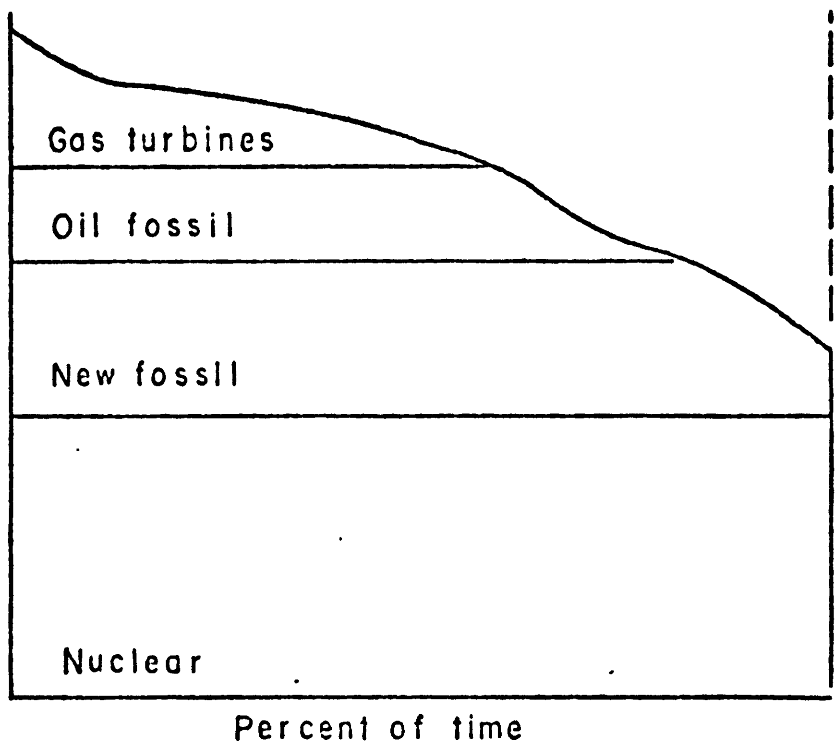


Figure III.2(c)

FIGURE III-3



Equivalent schedule on a load duration curve.

its loading point and the loading point of the next unit.

In the deterministic model, the conventional power plant with the lowest marginal cost is loaded under the customer demand curve at a derated capacity that reflects the plant's availability. For example, a 1000 MW plant with an 80 percent availability factor would be brought up to 800 MW. This plant generates as much energy as it can to meet the customer demand. Since if there is still unmet demand, the unit with the next lowest marginal cost is brought on line. This process continues until all the area under the load duration curve has been filled in. The total cost of the system operation can be computed by multiplying each plant's total megawatt hours by the cost per megawatt-hour for that plant and then summing the costs over all plants.

A deterministic model of this sort tends to underestimate the total cost of electricity, since plants are assumed to be available when required. Uncertainties in demand are also ignored. Both of these problems can be addressed by treating both demand and supply as random variables. Each power plant has a probability of failure and an expected time that it remains in a state of failure. Electrical demand has a probability of being at a given level and an expected time that it remains at that level. A complete description of the probabilitic model can be found in Finger (1981).

The total operating costs of the utility are then passed on to a rate-setting model. The primary purpose of this model is to estimate the capital costs of producing electricity, allocate them to the different customer classes and then add the capital costs to the fuel cost of electricity. As described above, two sets of rates are estimated. The first of these is the conventional regulated rate. The total revenue that must be collected includes enough money to pay all fuel bills, operating costs, taxes, plus an allowed rate of return on all previous investments. The required revenue for each plant for a given year is

$$RR = rK + C + d + T$$

where

RR is the required revenue,

K is the book value of all plants and transmission systems,

C is the fuel and operating cost of that plant,

d is the depreciation on all plants in that year, and

T is the total tax bill, including property and income taxes.

The book value of the utility's investments are estimated by first adding interest costs incurred during construction to the construction costs and subtracting out investment tax credits. A constant proportion of this cost is then subtracted from the initial cost for each year of the plant's tax life, until the book value reaches zero. For instance, a plant completed in 1970 for a total cost of $100 million, with a tax life of 20 years will have depreciated by $10 million every year, so that its book value in 1982 is now $30 million. (Tax life does not equal actual life. The plant may still be operating in the year 2000 with a book value of zero.)

Plant costs are either estimated from information on year of construction and plant size or are taken from utility-provided information. Transmission and distribution investments may also be explicitly available or are estimated from information on growth in sales.

From all the undepreciated values are subtracted the proportion of the original cost that was financed by debt, rather than stockholders equity. All the undepreciated value of the equity portion of the utility's investments are then added together to form the "rate base", which is K in equation 1.

A second set of rates is estimated to reflect the long-run incremental (or marginal) cost of producing electricity. This is undertaken in two ways. The correct method, as described, for instance, in Cicchetti et al. (1977), is to construct a generation, transmission and distribution expansion plan that will allow the estimation of the average cost of electricity into the future. This average cost will depend on the forecast of future demand. The cost (or benefits) of increases (or decreases) in forecasted demand can then be estimated by, first, changing the forecast by small amounts, then redoing the expansion plan for each change and finally, measuring the change in total costs over the planning horizon. The change in total cost divided by the change in total production will be the long-run marginal cost of electricity.

This cost can be thought of as the expenses incurred per kilowatt-hour, to meet new demand for electricity with new plants. All customers are then charged that cost. An approximation of this cost would be to estimate what it would cost to replace the entire electric utility system at today's cost of capacity and compute the cost of a unit of electricity on the basis of this replacement cost and the cost of fuel from marginal plants.

This method, while an approximation, has the advantage of eliminating the need for a complicated generation expansion model. To estimate the replacement capital cost one merely replaces the historic cost with the cost of new plants of the same type. The annual cost of holding this capital is then estimated based upon a real rate of return and divided by the total production of electricity. An average cost of fuel from marginal plants is then added to the replacement capital cost.

Different rates are estimated for two classes of customers; the large commercial and industrial class and the small commerical and residential class. The difference in rates between these classes is due to differences in billing and overhead costs and differences in the amount of transmission and distribution equipment needed to provide a kilowatt-hour of electricity to each of the classes.

Distributed Power Model

Since the levels of production of distributed power systems are not under the control of the central utility they violate some of the assumptions of the probabilistic production-costing model. One feature of photovoltaics, however, is that their operating costs are virtually zero. Any system that has such a low operating cost will be used whenever it is available, whether it is dispersed or owned by the central utility.

This suggests a straight-forward manner of incorporating photovoltaics systems into the economic modelling system. Hourly readings of solar insolation are available for many years for many locations in the U.S. Also, the hour-by-hour demand for electricity faced by the utility at these locations is also known. If we assume a certain amount of photovoltaic investment, then we can convert the insolation readings into capacity output and subtract that from the hourly electricity demand readings. Ideally, the solar insolation readings and the demand figures should be for the same hour of the same year for the same location. In that manner it is possible to capture the effect of the relationship between amount of sunlight and demand for electricity, a relationship that may arise out of the demand for air conditioning, for instance.

Once a new net load is created, the total demand is reordered into the load duration curve. The new load duration curve can then be fed back into the production costing model and rate-setting model to establish the impact of photovoltaics on utility costs and revenues. The new load duration curve is also passed to the generation expansion model, which is then re-run in order to examine the long-run cost implications of reduced demand in the future.

Measurement of Reliability and the Capacity Value of Photovoltaics

No electric utility is perfectly reliable. The high cost of having the necessary generating and distributing capacity in place to be perfectly reliable is greater than most people would be willing to pay. In assessing the value of a distributed energy system, some target of reliability must be set.

One measure of reliability that is often used is Loss of Load Probability (LOLP). The LOLP is the number of hours that the system is expected to fail over a given time period. Target LOLP's for most utilities are about one hour of failing to meet demand per year. When interconnection with other utilities is included in the estimation, this figure reduces to one hour every ten years, or a LOLP of .001 percent.

The LOLP can be derived graphically from the load duration curve. Figure III.2(a) shows the load duration curve of some utility while Figure III.2(b) shows the load duration curve transformed into an "equivalent load duration curve." It is derived by adding to the electric load handled by a plant, the "load" that arises due to breakdowns of plants that are lower in the loading order. Each plant handles its usual load plus the load arising out of the unpreparedness of more efficient plants.[5]

Once the load duration curve has been extended into an equivalent load duration curve we can find the LOLP. This is done by reading up from the maximum installed capacity to the newly generated curve. In Figure III.2(b) the utility's maximum capacity is U. Reading upward to point labeled L gives us the LOLP, which is the probability read off the vertical axis at height UL.

The use of the LOLP provides a handy tool for measuring the capacity contribution of photovoltaics and some other dispersed generators. The objective here is to find the amount of 100 percent reliable capacity that could be subtracted from the utility's capital stock and still maintain the same level of reliability.

The procedure can be described with the help of Figure III.4, which shows two load duration curves, F and F'. Demand level U is again the total rated capacity of the utility's system, and the distance UL is the Loss-of-Load Probability with the original load. F' is the load duration curve after K megawatts of photovoltaics have been added to the grid. The horizontal distance between F and F' at height UL represents the rated capacity that the utility could do without and still maintain the same Loss of Load Probability. This distance is labeled ELCC for Effective Load Carrying Capacity.

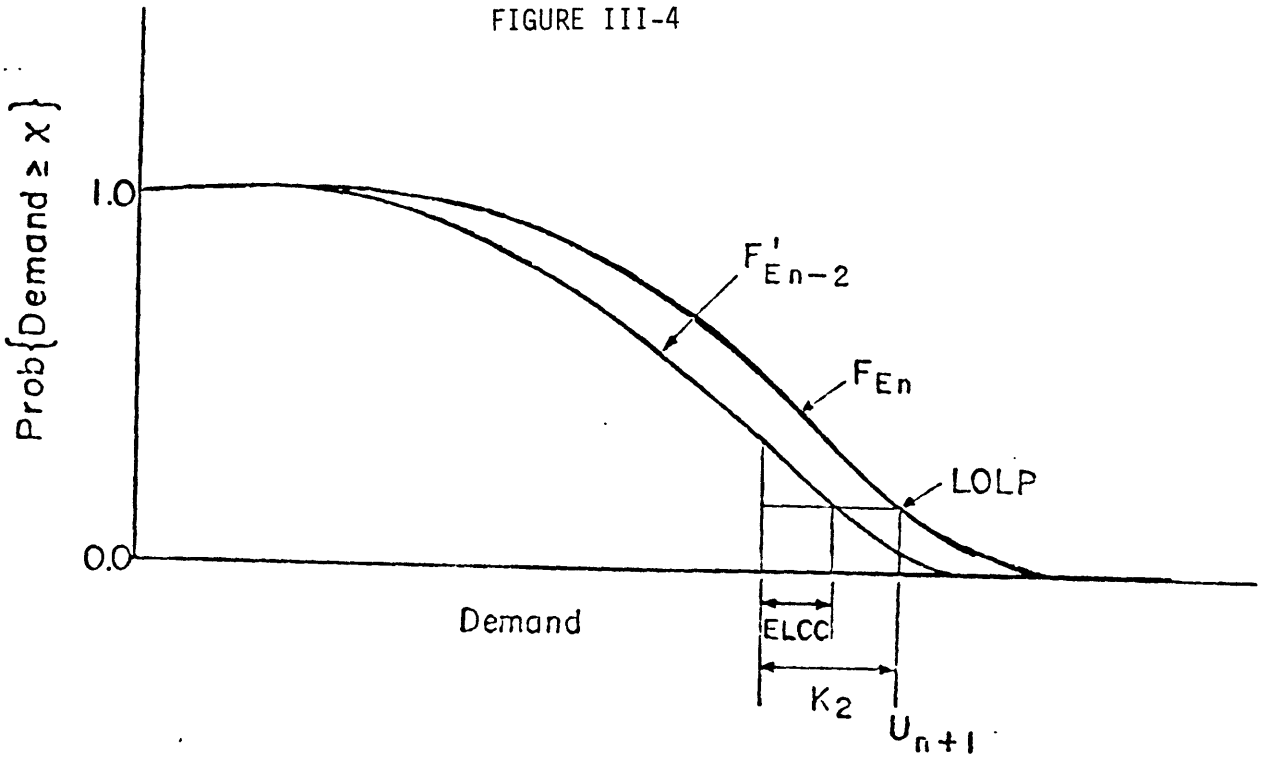
3.0 Analysis of Photovoltaic Worth

3.1 The Effective Load Carrying Capacity of Photovoltaics in Four Cities

Table III.1 gives our estimates of the ELCC for four cities. These

[5]The vertical axis of this cumulative probability function is the probability that a unit operates at a given capacity for a certain proportion of time.

FIGURE III-4



EQUIVALENT LOAD CARRYING CAPABILITY FOR PLANT 2.

Table III.1

Effective Capacity of Photovoltaics

City	Photovoltaic Nameplate Capacity 1 (MW)	2 as a percent of utility system	3	Photovoltaic Effective Capacity 4 as a percent of name-plate	Photovoltaic Output 5 (GWh/yr)
Miami	200	3.7	59	29.5	360.2
	1200	22.2	165	23.8	2203.7
Omaha	200	3.7	19	9.5	289.6
	1200	22.2	74	6.2	1754.9
Phoenix	200	3.2	80	40.0	404.5
	1200	19.1	407	33.9	2509.6
Boston[1]	200	3.7	71	35.5	253.7
	1200	22.2	304	25.3	1593.6

[1]Boston results using 1975 electricity demand data and 1953 insolation data. Miami, Omaha, and Phoenix utilize 1975 demand and insolation data.

results were generated by comparing hourly insolation readings for three of the cities with the local utility's hourly demand for electricity. Hourly demand for electricity was scaled up to the size required for the synthetic utility simulation. The hour-by-hour comparisons are made for 1975. For the fourth city, Boston, hourly insolation readings were not available for 1975, and so a "typical" year's data were used, 1953.

Column 1 of Table III.1 lists the assumed number of megawatts of photovoltaics that have been connected to the utility grid. Column 2 shows this photovoltaic capacity as a percentage of the peak demand that the local utility faced during the year (scaled to meet the requirements of the synthetic utilities). The third column of the table, "Photovoltaic Effective Capacity," is the effective load-carrying capacity of the photovoltaics. Column 4 shows these numbers as a percentage of the rated peak capacity of all photovoltaic systems. Finally, in column 5, we show our estimates of what the assumed photovoltaic capacity would produce in one year.

The most striking conclusion from these results is the very high effective capacity in Phoenix, Boston, and Miami. In the first two, there seems to be a strong correlation between insolation and some component of electricity demand, probably air conditioning. If hour-by-hour insolation figures had been available, the ELCC for Boston may have been even higher. In a city such as Omaha, on the othr hand, air conditioning demand is, no doubt, high during long periods of at least some cloud cover.

These high effective load-carrying capabilities have been found in other studies. General Electric (1979) showed results very similar to those in Table III.1, while Systems Control (1979) utilizing a somewhat cruder model got effective load-carrying capacities of 50 percent for Albuquerque. For a comparison of these results, see Cox (1981).

3.2 Utility Rates

One of the important purposes of developing the modeling system was to link together traditional electric generation analysis with an analysis of dispersed power systems. The critical link in this analysis has been the setting of consistent rates and the ability to calculate the buyback rate which a utility could afford to pay for excess user generated power. The next section will discuss the buyback rate while this section discusses the sell rates.

There is insufficient space within this report to discuss the rationale for the development of alternative utility rates. To summarize our previous discussions, the work completed has developed rates based upon standard utility regulatory practices as well as upon the more recently suggested rate structures contained both in the economic literature and in the PURPA legislation. Most simply stated, the current rates for a utility are set by customer class so that the company can cover costs and return a fair rate on their invested capital. Replacement rates involve recovering operating costs but setting the capital component of costs at the level that would be required to build or replace the next unit. Under time of day rates, the cost of capital can either be allocated to the peak and base periods in proportion to that of rate of use of capital stocks or can be attributed only to the peak. The five rates developed cover this spectrum of possible rates. The utility rates developed for each of the regional utilities under the assumptions listed above are shown summarized in Table III.2.

The significance of the rate structure on introduction of dispersed

Table III.2

UTILITY RATES Mills/kWh (1980 $)

Rate	Phoenix R	Phoenix I	Boston R	Boston I	Omaha R	Omaha I	Miami R	Miami I
1	43.7	36.7	52.1	41.6	44.5	34.5	48.2	39.9
2A	51.7	43.5	1112.2*	1042.7*	109.1	95.5	747.1*	712.2*
2B	33.9	29.0	41.8	34.5	28.2	21.0	39.3	33.2
3A	44.1	37.5	81.8*	72.2*	48.5	39.3	68.6*	60.9*
3B	41.7	35.4	50.6	40.3	41.1	31.9	46.8	38.7
4	69.6	61.4	73.5	60.2	67.9	60.5	65.7	54.4
5A	79.0	65.6	207.9*	177.7*	88.9	81.5	151.2*	129.4*
5B	67.5	59.5	70.2	57.5	62.2	54.9	62.8	52.1

R = Residential/Commercial I = Industrial

*Peak over short time period

Rate	Name
1	Flat embedded
2	T-O-D Embedded, nonallocated
2A	Peak
2B	Off-Peak
3	T-O-D Embedded, allocated
3A	Peak
3B	Off-Peak
4	Flat replacement
5	T-O-D Replacement, allocated
5A	Peak
5B	Off-Peak

generation is obvious. If a user faces a replacement rate structure, the dispersed system owner receives implicit credit for substituting for capital stock at the cost of the next unit, rather than at the average cost of units already built, as is the case with the embedded rates. Table III.3 shows, for Phoenix, the impact that alternative rates, flat-embedded versus flat-replacement, have upon the worth of photovoltaic power systems to a residential owner.

3.3 Utility Buyback

A major purpose in developing the modeling structure discussed above is to analyze utility buyback rates. We will develop this in two stages. Initially we provide an estimate of the average price that the utility would be willing to pay for a kilowatt-hour of electricity purchased from a photovoltaic producer. This is the price which the utility could pay and which would not violate the rule that its customers would be no better or worse off as a result of such a purchase. Secondly, we will establish a set of buy-back rates that will reflect the actual value of electricity sold to the grid, a value that is slightly lower than that which would comply with such an equal preference rule.

Table III.4 summarizes, for two levels of construction of photovoltaic systems, the value of electricity sold by these systems' owners to the utility. The table is divided into two halves, the left side being the rate estimated on the basis of "embedded" capital costs and the right side on the basis of "replacement" capital costs. Fuel credits are the same in both cases.

The results are striking. The utility can pay a high proportion of its selling rate to buy power back from dispersed generators. In Boston the buy-back rate under the flat, embedded scenario is 83 percent of the

Table III.3

IMPACT OF ALTERNATIVE RATES ON PV SYSTEM WORTH:
PHOENIX (1980 $)

	Utility Rate mills/kWh	Buyback mills/kWh	Rate pct.	System BECC/Wp
Embedded	43.7	35.4	81	1.15
Replacement	82.7	62.8	76	1.83

*See note on Table 1.

selling rate, in Phoenix 81 percent. For the flat replacement structure the results are similar, though lower, the proportions being 81 percent for Boston and 76 percent for Phoenix.

While a buy-back rate estimated on the basis of the average value of the utility's capital would be consistent with current practice for estimating selling rates, it does not represent the "avoided cost" as mentioned in PURPA regulations. The capital component of the true avoided cost must be the cost of electricity from generating plants delayed or not constructed. Again, replacement cost is used as a surrogate to estimate the true cost savings to the utility of purchases from photovoltaic systems. This is the price that would make the utility and its other customers indifferent between the utility's purchase of the excess photovoltaic electricity or its purchase of a new power generating system.

Under these conflicting rules for selling and buying back electricity the selling rate must be taken from row 1 of Table III.2 and the avoided cost buy-back rates from the right side of Table III.4. The result is that, depending upon the penetration level, the buy-back rate can be higher than the utility's allowed selling rate.*

However, the story cannot end here. The true value of solar electricity sold back to the grid is the value of the last unit bought back. As we mentioned above, and as we see from Table III.4, the value of photovoltaic energy drops with increasing levels of penetration.

---

*If the utility were also allowed to charge the avoided cost for electricity sales, as economic considerations indicate they should, then the selling rate would be row 5 of Table III.2 and the buy-back rate percentages would be those found in the right-hand column of Table III.4 (all less than 100 percent).

Table III.4

VALUE OF BUYBACK ELECTRICITY

Region & Capacity	Embedded Mills/kWh	pct	Replacement Mills/kWh	pct.
Phoenix				
200	35	81	51	73
1200	33	76	48	69
Boston				
200	43	83	60	81
1200	35	68	54	73
Omaha				
200	31	70	34	50
1200	30	67	32	47
Miami				
200	39	80	47	71
1200	31	64	43	66

However, Table III.4 only provides the displacement value of the average kilowatt-hour of solar electricity.

We can appproximate the marginal rate by taking a first difference between the total value of photovoltaic electricity with respect to the difference in the number of kilowatt-hours generated by the photovoltaic systems. That is, the marginal rate is

$$MR = \frac{V(200) - V(1200)}{PVKWH(200) - PVKWH(1200)}$$

where

V(200) is	the total dollar value of all electricity produced by 200 MW of photovoltaic arrays,
V(1200) is	the same value for 1200 MW,
PVKWH(200) is	the amount of electricity produced by 200 MW of photovoltaic arrays,
PVKWH(1200) is	the same for 1200 MW.

We have estimated these marginal avoided costs for two utilities. They are entered in column 2 of Table 5. Table 5 is a sample residential rate table for the Phoenix and Boston synthetic utilities, that we expect will be typical of the sorts of rates that will be offered under PURPA. These will maintain the traditional (though incorrect) embedded rates for sales by the utility, but will require the appropriate avoided costs for sales to the utility. Column 1 of Table III.5 is taken from row 1 of Table III.2.

Table III.5

SAMPLE RATES FOR ELECTRICITY--RESIDENTIAL/COMMERCIAL
Mills/kWh (1980$)

	(1) Selling Rate (Embedded)	(2) Buy-back Rate (Marginal Avoided Cost)
Phoenix	43.7	45
Boston	52.1	52.4

The marginal avoided cost buy-back rate is only slightly lower than the average buy-back rate estimated for the 1200 MW cases since the average rates drop relatively slowly. Nevertheless, the buy-back rates are still greater than the selling rate. Buy-back rates will drop below selling rates once other costs of buying back power from distributed generators are taken into account. This will include additional metering and safety equipment, administration and the production of reactive power, in the case of low power factor photovoltaic production.

4.0 Conclusions

The models developed in this effort allow the analysis of the effect of dispersed generation on a utility's operating and capital costs. This value, plus other data on the utility structure, can then be translated into representative utility rates.

In the example used, that of photovoltaic systems, the distibuted generation gains both a capital and an operating credit. While the level of these credits varies with utility and location, the capital credit ranged from 26 percent to 20 percent of the total credit.

Buyback rates for specific utilities are greater than 80 percent of the selling rates for the same time period. Rates of this magnitude will have a major impact on the configuration and optimal sizing of dispersed power systems in distributed applications and upon the requirements for and economics of storage.

REFERENCES

[1] Federal Energy Regulatory Commission, Orders 69 and 70. February 19, 1980.

[2] A.E. Kahn, The Economics of Regulation: Principles and Institutions, vol. 1. John Wiley, 1970.

[3] P.R. Carpenter and G.A. Taylor, "An economic analysis of grid-connected residential solar photovoltaic power systems." Energy Laboratory, M.I.T., Cambridge, MA. No. MIT-EL 78-007, May 1978.

[4] A.J. Cox, "The economics of photovoltaics in the commercial, institutional and industrial Sectors, MIT Energy Laboratory Report No. MIT-EL 80-008, revised April 1980.

[5] T.L. Dinwoodie and A.J. Cox, "The impact on photovoltaic worth of utility rates and reforms of specific market financial and policy variables," MIT Energy Laboratory Report No. MIT-EL 80-025, September 1980.

[6] S. Finger, "Electric power system production costing and relaibility analysis including hydro-electric, storage and time dependent power plants." MIT Energy Laboratory Technical Report No. MIT-EL 79-006.

[7] Electric Power Research Institute, "Synthetic electric utility systems for evaluating advanced technologies." Palo Alto, CA, February 1977.

[8] A.J. Cox and R.D. Tabors, "The interaction of electric utility operations, rate setting and distributed photovoltaic generation." Forthcoming Technical Report, Energy Laboratory, MIT.

[9] C.J. Cicchetti, W.J. Gillen, P. Smolensky, The Marginal Cost and Pricing of Electricity, An Applied Approach. Ballinger, Cambridge, MA, 1977.

[10] M.L. Baughman and D.J. Bottaro, "Electric power transmission and distribution systems: Costs and their allocation." IEEE Transactions on Power Apparatus and Systems, vol. PAS-95, p. 784, May/June 1976.

[11] M. Mohammadioun, "Regional analysis of transmission and distribution needs and costs in the United States." U. of Texas at Austin, Center for Energy Studies, 1979.

[12] R. Turvey and D. Anderson, Electricity Economics. Johns Hopkins University Press, Washington, 1977.

[13] H. Baleriaux, E. Jamoulle, and F. Linard de Guertechin, "Simulation de l'exploitation d'un parc de machines thermiques de production d'electricite couple a des stations to pompage," Revue E, vol. V., bo. 7, pp. 225-245, 1967.

[14] R.R. Booth, "Power system simulation model based on probability analysis," IEEE Transactions on Power Apparatus and Systems, vol. PAS-91, pp. 62-69, January/February 1972.

[15] G.R. Fegan, and C.D. Percival, "Integration of intermittent sources into Baleriaux-Booth production cost models," presented at IEEE Winter Power Meeting, New York, NY, 1979.

[16] Tabors, R.D., S. Finger, et al., "SERI photovoltaic venture analysis: Long-term demand estimation." Energy Laboratory Report No. MIT-EL 78-032, July 1978.

[17] U.S. Federal Power Commission, "Steam plant construction cost and annual production expenses, twenty-fourth annual supplement," Washington, 1971.

[18] Handy-Whitman Index of Public Utility Construction Costs, Whitman, Requardt and Associates, Baltimore, MD, September 1980.

[19] Monthly Energy Review, U.S. Department of Energy, DOE/EIA 0035/10(80).

[20] T.L. Dinwoodie, "OESYS: A simulation tool for non-conventional energy applications analysis, description and documentation," MIT Energy Laboratory Report No. MIT-EL 80-022, August 1980.

82 WM 008-1

THE INTRODUCTION OF NON-DISPATCHABLE TECHNOLOGIES AS DECISION VARIABLES IN LONG-TERM GENERATION EXPANSION MODELS

Michael C. Caramanis Richard D. Tabors Kumar S. Nochur
MIT Energy Laboratory

Fred C. Schweppe
MIT Dept. of Electrical Engineering

Abstract Non-dispatchable technologies (solar, wind, run-of-the-river hydro, cogeneration) affect the cost of electricity production in a complex manner by modifying the probability distribution of demand for conventional generation. The lack of an appropriate methodology to efficiently derive this modification has prevented inclusion of non-dispatchable technologies as decision variables in capacity expansion models. This paper develops a stochastic approach to load modification which explicitly models two types of interdependencies between load and non-dispatchable generation: through time of day and through weather. If more than one non-dispatchable generation technology is considered, the dependency among them is also modeled. Furthermore, the total as well as the marginal impact of non-dispatchable capacity on system reliability and operating cost is derived. This allows us to model non-dispatchable generation in the context of two broad classes of optimization algorithms. Dynamic programming and mathematical decomposition are considered in this paper as characteristic examples of algorithms in each class. Load modification models already in use derive total cost impact only, and are based on hourly chronological simulation which is a computationally cumbersome method. The methodology developed here provides marginal impact in addition to total impact values, is computationally efficient and is applicable to future demand projections at almost any level of detail. Finally, its accuracy proved very satisfactory when tested on 1975 Miami load and insolation data.

INTRODUCTION

Non-dispatchable technologies (NDT) affect the cost of electricity generation through a complex interaction with energy and capacity requirements to be met by conventional dispatchable generation (thermal, hydro, central storage, etc.). These interactions may be properly represented in the context of long-term capacity expansion models if the total and marginal impact of NDT on system reliability and operation costs can be estimated. Thus, an efficient methodology to derive this impact is the basic prerequisite for the inclusion of NDT as decision variables in capacity expansion models.

This paper presents a stochastic approach for estimating the impact of NDT where load and NDT generation are treated as dependent random variables. Two types of dependencies are handled explicitly: through time of day or season, and through weather. The stochastic approach is tested on real Miami 1975 data and compared for accuracy to a chronological simulation model. The analytic calculation of marginal impact developed in this paper is a unique capability of the stochastic approach.

Use of the stochastic load modification approach in the context of two capacity expansion models, allowing NDT installed capacities to be treated as decision variables, is also demonstrated. The two models chosen are based on Dynamic Programming and Generalized Bender's Decomposition, but are representative of a wide range of models. The Dynamic Program is representative of models which require endogenous determination of system cost and reliability associated with a particular mix of generating capacity. The Generalized Benders' Decomposition algorithm is representative of models with additional requirements for endogeous determination of the impact of marginal generating capacity changes on system cost and reliability.

Finally, the methodology developed here is compared to load modification models based on chronological simulation. The advantages and disadvantages of the stochastic and chronological approaches are evaluated from the point of view of their usefulness in the context of capacity expansion planning models.

DERIVING THE LOAD DURATION CURVE NET OF NDT GENERATION

Methodology

Randomness in customer demand and availability of generating capacity are essential features which must be addressed and carefully modeled by generation expansion planning tools. Baleriaux and Booth ([1] and [3]) have formulated a computationally efficient algorithm that is sufficiently accurate for planning purposes. The methodology presented here is an extension of the basic Baleriaux and Booth probabilistic production costing framework to handle NDT generation.

The Baleriaux formulation rests on the representation of customer demand and forced outages of dispatchable generating units as independent random variables. Load is represented by the load duration curve (LDC) which may be constructed by sorting load in order of increasing hourly values to obtain the proportion of time during a period of concern that load is expected to exceed a certain level. In doing this the time series character of hourly loads is collapsed into a probability distribution that models load as a random variable which is assumed to be independent of the forced outages of dispatchable units. The independence assumption is justifiable for dispatchable generation only. In contrast, NDT generation, if modeled as a random variable, is interdependent with load. Further, outputs from units belonging to different NDTs are also interdependent. Recognizing this, the methodology proposed here addresses the problem of deriving the probability distribution of

82 WM 008-1 A paper recommended and approved by the IEEE Power System Engineering Committee of the IEEE Power Engineering Society for presentation at the IEEE PES 1982 Winter Meeting, New York, New York, January 31-February 5, 1982. Manuscript submitted August 3, 1981; made available for printing October 23, 1981.

the sum of statistically interdependent random variables. The sum is customer load net of NDT generation while the interdependent random variables are initial customer load and the various NDT generation types.

In order to address the interdependency question, we observe that the probability distributions of initial customer demand and NDT generation summarize variations which result from two different phenomena: a cyclic phenomenon (time of day, day of the week, season) and a random phenomenon (temperature, cloud cover, wind speed). We then proceed to separate the cyclic from the random phenomenon by defining cycles spanning the period of concern and categorizing load and NDT generation according to the position in the cycle in which they occur. For example, if the period of concern is winter of 1980, we may specify a daily cycle* spanning the period, with positions in the cycle corresponding to times of day. It should be noted that in the above categorization the number of random variables representing load and each distinct NDT site-technology combination increases by a factor equal to the number of cycle positions defined. In the above example, if five time of day categories are defined as the different possible positions in the daily cycle, and we wish to analyze two NDT generation types in one site, then the categorization according to time of day will result in fifteen random variables representing load and NDT generation.

In probability theory terms, the above categorization is equivalent to conditioning load and NDT generation on time of day. We next focus on deriving modified customer load net of NDT generation conditional upon time of day. Once this is achieved, aggregation to obtain modified customer load for the whole period of concern may be easily implemented (see Appendix A).

Although conditioning on time of day removes part of the dependence, conditional load and NDT generation are still interdependent because of their common dependence on weather (wind speed, temperature, insolation) and other random phenomena. This interdependence of the conditional random variables is explicitly modeled by constructing a linear transformation of the dependent variables that yields an equal number of independent random variables. The transformation is obtained by applying Gram-Schmidt Orthogonalization on the original joint hourly observations of load and the various types of interdependent NDT generation for each time of day category. The transformation summarizes in essence the joint probability distribution of demand and NDT generation conditional upon the time of day, assuming a linear underlying relationship. It also yields mutually independent random variables which may be easily combined to derive the probability distribution of load net of NDT generation.

The mathematical details of the stochastic approach outlined above as well as its algorithmic implementation are presented in Appendix A. To give the reader an overview of the modeling capabilities of the approach, the exposition is restricted here to the problem formulation and a non-mathematical treatment of the various issues is presented.

*More than one cycle may be defined if desired, for example, weekdays and weekends.

The problem of estimating modified customer load net of NDT generation is tantamount to the construction of its probability distribution. Modified load, modeled as a random variable, is related in the proposed methodology to initial customer load and NDT generation as follows:

$$\tilde{Y}^* = \tilde{Y} - \sum_{i,j} \tilde{E}_i \tilde{X}_{ij} \qquad (1)$$

where

- $\tilde{Y}^*$: Random variable representing <u>modified load</u>
- $\tilde{Y}$: Random variable representing <u>original customer load</u>
- i : Index identifying technology and installation site
- $\tilde{E}_i$: Random variable representing <u>"energy source" availability</u> related <u>to technology-site combination</u> i. It corresponds to the hourly output of one MW of installed capacity in site-technology i, assuming no equipment failures.
- $\tilde{X}_{ij}$: Random variable representing <u>"generating capacity" availability</u> of <u>unit j related to site-technology</u> i, after accounting for forced outages. Note that forced outages correspond to unpredictable equipment failures, resulting in a random fraction of installed capacity being available at any given point of time.

The following points describe the modeling capabilities of the above formulation.

- NDT generation is modeled accurately as the product of two random variables-- i) energy source availability $\tilde{E}_i$, which varies with time of day, weather (wind speed, solar insolation, etc.) and other random phenomena, and ii) generating capacity availability $\tilde{X}_{ij}$, which varies with random equipment failures. $\tilde{X}_{ij}$ models hardware reliability and is exactly equivalent to the modeling of forced outages of conventional dispatchable units in probabilistic production costing. Thus $\tilde{X}_{ij}$ may either be specified as a binary state random variable or, if more detail is desired, as a multi-state random variable using multiple block specification. $\tilde{E}_i$, on the other hand, models the non-dispatchable character of NDT generation associated with site-technology i. It has a continuous probability distribution and is interdependent both with initial customer load and energy source availabilities related to other sites and/or technologies. It should be noted that the above formulation makes it possible to simultaneously model and evaluate a wide range of NDT's characterized by type of technology, installation site, unit size and equipment reliability.

- Multiple unit installations X_{ij} with j varying over units related to a particular technology-site may be modeled. These units must have the same conversion efficiency, thus sharing the same E_i, but may exhibit different size and installed capacity availabilities. Thus, for example, photovoltaic arrays of different sizes installed in the same site with varying hardware reliability specifications may be modeled to reflect different institutional ownership patterns and maintenance assumptions.

- An important consequence of the fact that the interdependent random variables $\tilde{Y}$ and $\tilde{E}_i$, i = 1, 2, ... are statistically independent of the actual levels of generating capacity availabilities $\tilde{X}_{ij}$ is the following. The joint probability distribution of $\tilde{Y}$ and $\tilde{E}_i$, i = 1, 2, ... may be accounted for just once and then used repeatedly to derive modified load in relation to different NDT generating capacity levels. Thus, the stochastic load modification methodology developed here is computationally efficient in the context of capacity expansion planning, since modified load associated with alternative plans may be derived with minimal incremental computational effort.

- The representation of NDT generation used above is sufficiently general to apply to a wide range of technologies. Besides the new energy technologies like solar and wind energy conversion, the following broadly-construed NDT generation or avoided generation may be modeled in the formulation of equation 1: run of the river hydro, heat following steam-electricity cogeneration, energy conservation investments like insulation, and certain load management techniques. In all of the above, an hourly performance simulation of a particular NDT during a base year is sufficient information for building its joint probability distribution with load and other NDT options. Derivation of modified load duration curves for various NDT installation plans is then feasible.

The probability distribution of load is converted, in line with standard industry practice, into a load duration curve (which is often represented by a piecewise linear curve). The methodology developed here yields an LDC for modified load which may then be used to perform Baleriaux and Booth probabilistic production costing on the conventional dispatchable units. Although the modified LDC may be represented by a piecewise linear curve, it is derived in the proposed methodology in terms of a finite Gram-Charlier series [8] utilizing the first eight moments or cumulants of modified load $\tilde{Y}^*$. Hence, as is more explicitly stated in Appendix A, the statistical load modification approach developed here is based on the estimation of the first eight moments of $\tilde{Y}^*$. Once these moments are obtained, the LDC of modified load is constructed using the Gram-Charlier series which may in turn be used to alternatively define a piecewise linear LDC, or any other LDC representation that might be required.

Empirical Investigation of Accuracy Performance

The statistical load modification methodology outlined above was implemented in a computer code (see Appendix A) and tested on 1975 Miami load and solar energy flux data. One technology-site was considered, with two NDT generators. The generators were assumed to consist of photovoltaic arrays with peak capacities of 800 MW and 300 MW and average installed capacity availabilities of 70 percent and 80 percent respectively. Miami 1975 hourly load information was obtained from EEI and hourly solar energy flux for 1975 was obtained from the SOLMET weather tapes. The solar energy flux data were input to a photovoltaic generation simulator which yielded base year hourly values of E_i, that is, observations of the energy source availability.

The data described above were used to obtain two estimates of modified load. The first estimate was obtained following the stochastic approach developed here while the second was obtained using an explicit hourly chronological simulation algorithm [5]. The chronological simulation algorithm loops over every hour in the period of concern and subtracts NDT generation from load for each possible state of installed capacity availabilities. The resulting hourly modified load for each state of capacity availability was turned into a load duration curve by calculating the first eight moments, treating hourly values as observations from an underlying probability distribution. The Gram-Charlier series was then used to generate values on the LDC of modified load and these were then plotted. The stochastic approach algorithm groups hourly load and NDT energy source availability data into eleven time-of-day categories. In the final step of the statistical approach, the first eight moments/cumulants of modified load are calculated for the specified installed capacity levels and time-of-day results are aggregated to results for the whole period. The Gram-Charlier series was then used to generate the LDC of modified load.

First, the period of concern was taken to cover the whole year. Then the analysis was repeated for shorter periods referring to each season of the year (Winter, Spring, Summer, Fall) and further distinguishing between weekdays and weekends. Division of the year into subyearly periods and performance of probabilistic production costing for each one is common practice when detailed modeling, capable of addressing maintenance scheduling and storage, is required. Thus, it was considered interesting to test the accuracy of the stochastic approach on both yearly and subyearly LDC specifications.

The results for the yearly LDC specification are presented in Figure 1 and Table 1 which cover original load and modified load following the stochastic and chronological approach. The chronological approach is used here as a benchmark. As may be observed, the difference between the chronological simulation and stochastic approach results is smaller than the plotter's resolution. Table 1 gives probability values up to the fourth decimal point which allows for more detailed comparison. Point estimates on the LDC corresponding to the stochastic approach differ from the benchmark by less than 0.1 percent in the mid-range of the LDC, while the difference increases towards the tails. It should be noted that while inaccuracies in the tails are very small in absolute terms and may hardly have any impact on production costing calculations, they are more important when reliability estimates are of interest. However, errors of a few percentage points in the loss of load probability or other related reliability estimates are not substantial in the context of probabilistic production costing. The Baleriaux and Booth assumptions for collapsing time into a probability distribution most likely introduce a larger relative error.

Table 1
Load Modification Results
All Seasons 1975
LDC Values For Selected Load Levels

Load Level Z (MW)	Probability Load > Z: Original Load	Modified Load: Stochastic Approach	Modified Load: Chronological Simulation
2500	1.0000	1.0000	1.0000
2700	0.9831	0.9794	0.9793
2900	0.9561	0.9441	0.9440
3100	0.9177	0.8943	0.8943
3300	0.8671	0.8303	0.8302
3500	0.8050	0.7537	0.7536
3700	0.7326	0.6678	0.6677
3900	0.6526	0.5770	0.5768
4100	0.5680	0.4859	0.4857
4300	0.4823	0.3988	0.3987
4500	0.3990	0.3192	0.3192
4700	0.3207	0.2439	0.2491
4900	0.2499	0.1887	0.1891
5100	0.1877	0.1386	0.1391
5300	0.1349	0.0976	0.0982
5500	0.0917	0.0651	0.0656
5700	0.0576	0.0402	0.0406
5900	0.0321	0.0220	0.0222
6100	0.0142	0.0095	0.0096
6300	0.0028	0.0020	0.0018
6500	0.0000	0.0000	0.0000

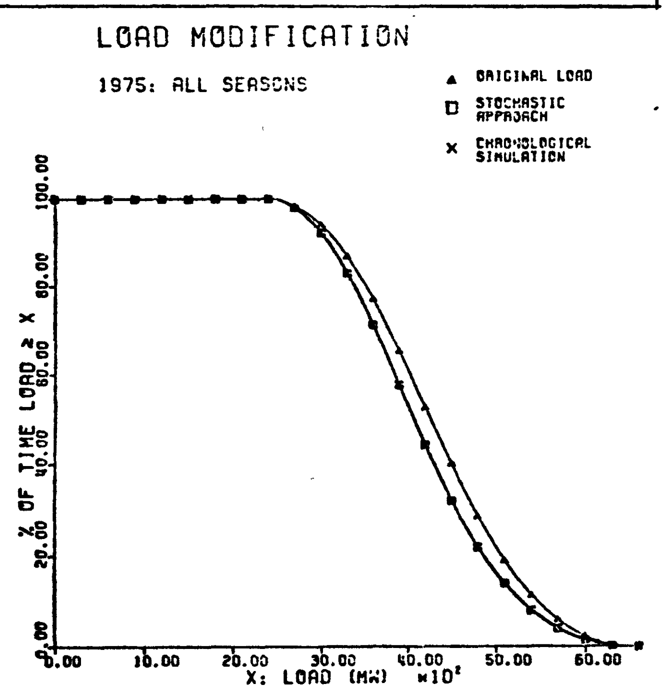


Figure 1

Differences between the stochastic approach and benchmark results stay in the same range as the duration of period covered by the LDC decreases. Table 2 gives point estimates on the LDC for a characteristic subyearly period covering winter weekends. The relative error for this shorter period LDC also does not exceed 0.1 percent in the midrange. The accuracy of the stochastic approach algorithm is still satisfactory. Discrepancies are due to small sample size rather than a systematic error. A systematic error would have resulted in compounding discrepancies as the length of the period considered increases and this is not observed here.

Table 2
Load Modification Results
Winter 1975: Weekends

LDC Values For Selected Load Levels

Load Level Z (MW)	Probability Load ≥ Z: Original Load	Modified Load: Stochastic Approach	Modified Load: Chronological Simulation
2100	1.0000	1.0000	1.0000
2300	0.9636	0.9672	0.9670
2500	0.9092	0.8941	0.8942
2700	0.8480	0.7957	0.7961
2900	0.7821	0.6777	0.6785
3100	0.7018	0.5470	0.5477
3300	0.5942	0.4125	0.4128
3500	0.4570	0.2860	0.2857
3700	0.3063	0.1789	0.1782
3900	0.1690	0.0983	0.0976
4100	0.0676	0.0450	0.0446
4300	0.0093	0.0146	0.0145
4500	0.0000	0.0003	0.0004

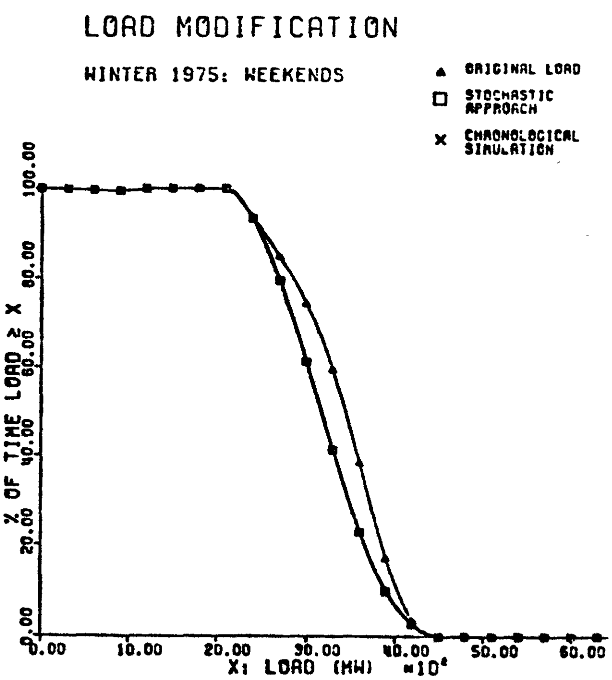


Figure 2

The accuracy comparison of the proposed stochastic approach should be followed by a computational efficiency comparison. For n units with binary capacity availblility (ie. a unit can be in one of two states—available or not available), the chronological simulation algorithm performs, in the case of a yearly period, $2^n * 8760$ subtractions and multiplications, and $2^n * 8 * 8760$ additions and exponentiations ($n = 2$ in the test data used). In comparison, the stochastic approach performs a comparable number of operations once and then estimates modified load for a particular installed capacity level by performing the following incremental operations: T * 8 * [n+4 additions, n+1 multiplications, 2 cumulants to moments conversions], where T is the number of time-of-day categories and n the number of units considered (T = 11 and n = 2 in the test data used).

The above comparisons are representative of the one technology test case used to generate the results presented above but are indicative of the computational efficiency of the two algorithms. The stochastic approach is more efficient by at least an order of magnitude. As the number of units considered increases, the efficiency advantage of the stochastic approach becomes even more pronounced.

INTERFACE WITH A DYNAMIC PROGRAMMING ALGORITHM

Dynamic programming (DP) algorithms have long been used to solve the long-range generation planning problem [7]. The building block of DP planning tools is the estimation of operating costs related to a particular combination of installed capacities that meet a specified reliability level in each year of the planning period. Repeated production cost calculations based on an LDC representation of customer load are thus performed and comprise the major computation effort involved.

If NDTs are part of the capacity expansion alternatives, the approach presented above may be used prior to production costing to derive a modified load duration curve net of NDT generation. Computational efficiency in deriving the modified load duration curve is of paramount importance given that such derivations must be performed many times (of the order of thousands). Many different levels of NDT generation capacity are considered each year, but the incremental computational effort required by the proposed methodology to derive modified load for each level is minimal. The computational efficiency of the stochastic load modification approach developed here makes the introduction of NDT generation in DP planning models feasible.

Chronological simulation load modification models have been used in relation to a DP algorithm [4] but only with NDT generation capacity specified exogenously. Treating NDT generation as a decision variable poses computational efficiency requirements that are not met by chronological simulation models.

INTERFACE WITH A GENERALIZED BENDERS' DECOMPOSITION ALGORITHM

A capacity planning model developed by J. Bloom [2] utilizing a Generalized Bender's decomposition algorithm is selected here to demonstrate the introduction of NDT in capacity expansion models that require marginal impact information. To define marginal impact precisely, it should be noted that the relevant quantities are system operating cost and reliability. In equation form,

$$\text{Operating cost} = OC = \sum_j F^j E^j + F^N \left(E - \sum_j E^j\right) \tag{2}$$

$$\text{Reliability} = \text{unserved energy} = \epsilon = E - \sum_j E^j \tag{3}$$

where E^j = expected energy generated by the jth conventional dispatchable unit in the loading order

F^j = variable cost of the jth unit

E = total customer energy demand

F^N = per unit cost of unmet demand

Noticing that F^j, F^N, and E are input constants and denoting NDT capacity by X_i, we obtain the following relations.

$$\frac{\partial OC}{\partial X_i} = \sum_j F^j \frac{\partial E^j}{\partial X_i} - F^N \sum_j \frac{\partial E^j}{\partial X_i} \tag{4}$$

$$\frac{\partial \epsilon}{\partial X_i} = - \sum_j \frac{\partial E^j}{\partial X_i} \tag{5}$$

Inspecting equations (4) and (5) it may be observed that the marginal impact on both operating cost and reliability is determined if $\frac{\partial E^j}{\partial X_i}$ is known for all i,j.

The remainder of this section will focus on deriving formulas for $\frac{\partial E^j}{\partial X_i}$. Consider the identity resulting from energy balance

$$E_j = U_{j-1} - U_j \tag{6}$$

where $U_j = E - \sum_{i=1}^{j} E_i$ = unmet demand after 1,2,...,j dispatchable units have been loaded under the load duration curve.

Differentiating (6) gives

$$\frac{\partial E_j}{\partial X_i} = \frac{\partial U_{j-1}}{\partial X_i} - \frac{\partial U_j}{\partial X_i} \tag{7}$$

Hence the evaluation of $\frac{\partial E_j}{\partial X_i}$ for all j is equivalent to the evaluation of $\frac{\partial U_j}{\partial X_i}$ for all j.

The probability distribution of equivalent load seen by the (j+1)th dispatchable unit may be represented in a fourth* order Gram-Charlier expansion [8] as follows:

$$P(z) = N(z) - \frac{G(3)}{3!} N^{(3)}(z) + \frac{G(4)}{4!} N^{(4)}(z) \tag{8}$$

where $N^{(k)}(z)$ = kth derivative of N(z) with respect to z,

*Sixth or eighth order Edgeworth or Gram Charlier is required for sufficient accuracy. Fourth order is used here to simplify the exposition.

$$N(z) = \sqrt{\frac{1}{2\pi}} \quad e^{-z^2/2}$$

$$G(r) = k(r)/[k(2)]^{1/2}$$

$$k(r) = \text{rth cumulant of } \tilde{Y}^* + \sum_{i=1}^{j} (\text{rth cumulant of } \tilde{F}_i)$$

$\tilde{F}_i$ = forced outage distribution of ith dispatchable unit

z = equivalent load normalized by $k(1)$ (zero mean) and $[k(2)]^{1/2}$ (unit standard deviation).

Unmet demand after the jth unit has been loaded can be written as

$$U_j = \left\{ \int_{z^*}^{\infty} [1 - \int_{-\infty}^{\xi} P(z)dz]d\xi \right\} * \text{hours} * [k(2)]^{1/2} \tag{9}$$

where z^* = the loading point of unit j + 1

hours = number of hours in period over which the load duration curve is defined.

Differentiating (9) with respect to capacity X_i we have

$$\frac{\partial U_j}{\partial X_i} = \quad [\phi(z^*) - 1] \; \frac{\partial z^*}{\partial X_i} - \frac{\partial k(3)}{\partial X_i} \frac{N^{(1)}(z^*)}{3!}$$

$$- \frac{k(3)}{3!} * N^{(2)}(z^*) \frac{\partial z^*}{\partial X_i} + \frac{\partial k(4)}{\partial X_i} \frac{N^{(2)}(z^*)}{4!}$$

$$+ \frac{k(4)}{4!} * N^{(3)}(z^*) \frac{\partial z^*}{\partial X_i} \quad * \text{hours} * [k(2)]^{1/2}$$

$$+ \frac{1}{2} [U_j/k(2)] \frac{\partial k(2)}{\partial X_i} \tag{10}$$

where

$$\phi(z^*) = \int_{-\infty}^{z^*} \sqrt{\frac{1}{2\pi}} \; e^{-z^2/2} \, dz$$

Noticing that

$$z^* = [\sum_{j'=1}^{j} Y_{j'} - k(1)]/[k(2)]^{1/2}$$

where $Y_{j'}$ is the installed capacity of the dispatchable unit j', it is obvious that (10) can be evaluated given $\frac{\partial k(r)}{\partial X_i}$. Inspecting the definition of k(r) and noting that the forced outages of dispatchable units are statistically independent of customer demand net of NDT generation, one may write

$$\frac{\partial k(r)}{\partial X_i} = \frac{\partial(\text{rth cumulant of } \tilde{Y}^*)}{\partial X_i} \tag{11}$$

Thus the problem of estimating $\frac{\partial E^j}{\partial X_i}$ has been reduced to that of estimating derivatives of the cumulants of $\tilde{Y}^*$ with respect to X_i. The derivation is presented for the case of one NDT capacity expansion alternative in Appendix B. The generalization to more than one alternative is straightforward. It is interesting to note that the derivative calculations presented in Appendix B may be carried out in parallel to the calculation of the cumulants/moments of $\tilde{Y}^*$ and do not pose undue additional computational burden.

This section has demonstrated that marginal impact of NDT capacity additions can be calculated. In his algorithm J. Bloom [2] has developed a recursion formula for estimating marginal impact of dispatchable capacity additions with a binomial forced outage distribution. The methodology presented here is applicable to nondispatchable as well as conventional dispatchable units*, but requires a finite Gram-Charlier series representation of initial customer demand and equivalent demand seen by each conventional unit. Bloom's recursion formula is applicable to a larger set of probabilistic production cost algorithms since it imposes no restrictions on load representations which can be, for example, piecewise linear, Gram-Charlier, Fourier series, etc. However, it is not extendable to handle NDT generation. In concluding this section, it should be noted that the requirement of a Gram-Charlier representation of load in order to handle NDT generation in long-term capacity expansion models is far from restrictive, since this representation is superior in computational efficiency and sufficiently accurate for the purpose of long-term capacity planning [9].

CONCLUSION AND COMPARATIVE EVALUATION

A stochastic approach was outlined above that derives the probability distribution of customer electricity demand net of NDT generation. Alternative approaches developed in the past [5] utilizing chronological simulation are the only substitute in the authors' knowledge and are thus chosen for comparison to the new stochastic method developed. The comparison is attempted in terms of the following issues.

---

*A Generalized Benders' algorithm with multiple unit interpretation of a continuous decision variable for dispatchable capacity added has been developed and implemented by the authors of this paper [10], based on a Gram-Charlier LDC representation. Extension to NDT generation has also been implemented. The authors have been recently informed of similar unpublished work by Richard B. Fancher of Decision Focus, Inc. who has independently rederived the Gram-Charlier based formulas giving derivatives of expected energy generated with respect to conventional generating capacity.

a. Compatible Production Cost Models. Load modification models using chronological simulation may be interfaced with both Booth-Baleriaux type probabilistic production cost models, as well as with hourly chronological production simulation models. The stochastic approach is compatible with Booth-Baleriaux production cost models only. Gram-Charlier finite series representation of load is required only when marginal impact information is required.

b. Accuracy and Computational Efficiency. The accuracy of chronological models is as good or better than that of the statistical model presented here, depending on the particular problem considered. However, the computational efficiency gains associated with the stochastic approach should make it the preferred option for applications in the context of long-term capacity planning. If a prespecified path of NDT capacity selection is to be analyzed, implying that customer load will have to be modified once for every year in the planning period, then chronological models might still be practical. If NDT generation is to be included as a decision variable in a long-term capacity planning model, computational efficiency requirements might render the stocashtic approach the only available option.

c. Marginal Impact Estimates. This paper develops analytic marginal impact calculations associated with NDT capacity additions. Marginal impact quantities required by a whole group of long-range planning models (Generalized Bender's decomposition, gradient algorithms, etc.) may not be obtained analytically in chronological simulation models, although numerical estimates are obtainable by perturbing each of the NDT analyzed, and then repeating production costing calculations for each technology. Numerical instabilities, in addition to computational burden, limit greatly the usefulness of this approach.

d. Modeling Scope Capabilities. The statistical approach presented here allows for a flexible and generally applicable modeling of NDT generation alternatives. Inspection of equation (1) shows that many site-technology combinations may be represented. All NDT generating capacity associated with each site-technology combination has the same conversion efficiency performance but may consist of multiple units with different sizes and/or availabilities. Thus, varying institutional ownership arrangements (e.g., distributed non-utility-owned vs. centralized utility-owned) related to different size requirements and hardware reliability may be easily modeled. In contrast, chronological models require a separate simulation for each state of the NDT generating units due to hardware forced outages, and as the multitude of these combinations increases exponentially, only a very small number of different units may be practically analyzed.

In concluding this paper, we would like to emphasize that its primary contribution lies in the stochastic approach developed for deriving modified load net of NDT generation. The proposed method is significantly more efficient than past approaches utilizing chronological simulation and is unique in that it allows analytic marginal impact calculations, which, if required, may render it the only available option.

APPENDIX A

THE LOAD MODIFICATION ALGORITHM

The problem formulated in equation (1) of the text takes the following form after categorization according to time of day, denoted by t:

$$\tilde{Y}^*(t) = \tilde{Y}(t) - \sum_{i,j} \tilde{E}_i(t) \cdot \tilde{X}_{ij} \quad \text{(A1)}$$

$t = 1, 2, \ldots$ time of day

To further account for the random (weather) component of dependence, it is assumed that random variables $\tilde{E}_i(t)$ for all i and $\tilde{Y}(t)$ are linearly related, and Gram-Schmidt orthogonalization is used to construct a linear transformation which relates $\tilde{E}_i(t)$ $(i = 1, 2, \ldots)$ and $\tilde{Y}(t)$ to mutually independent random variables $\tilde{R}_i(t)$ $(i = 1, 2, \ldots)$, $\tilde{R}_y(t)$. The transformation can be summarized in matrix notation as follows:

$$\begin{bmatrix} \tilde{E}_1(t) \\ \tilde{E}_2(t) \\ \tilde{E}_3(t) \\ \cdot \\ \tilde{E}_I(t) \\ \tilde{Y}(t) \end{bmatrix} = \begin{bmatrix} 1 & & & & & \\ a_{21}(t) & 1 & & & & \\ a_{31}(t) & a_{32}(t) & 1 & & & \\ \cdot & \cdot & \cdot & & & \\ a_{I1}(t) & a_{I2}(t) & a_{I3}(t) & \cdot\ \cdot & 1 & \\ a_{y1}(t) & a_{y2}(t) & a_{y3}(t) & \cdot\ \cdot & a_{yI}(t) & 1 \end{bmatrix} * \begin{bmatrix} \tilde{R}_1(t) \\ \tilde{R}_2(t) \\ \tilde{R}_3(t) \\ \cdot \\ \tilde{R}_I(t) \\ \tilde{R}_y(t) \end{bmatrix} + \begin{bmatrix} 0 \\ b_2(t) \\ b_3(t) \\ \cdot \\ \cdot \\ \cdot \\ b_I(t) \\ b_y(t) \end{bmatrix} \quad \text{(A2)}$$

The Gram-Charlier series expansion with finite terms used to represent the probability distribution of $\tilde{Y}^*$ may be expressed in terms of a finite number of cumulants of $\tilde{Y}^*$. Using the standard probability theory result that the cumulants of the sum of independent random variables are equal to the sum of the cumulants of the individual random variables, the linear relationship assumption made above may be accepted or rejected by testing the hypothesis that the following equality holds for higher than second order cumulants:

$$k_r[\tilde{R}_y(t) + \sum_i \tilde{R}_i(t)] = k_r[\tilde{R}_y(t)] + \sum_i k_r[\tilde{R}_i(t)]$$

where $k_r[*]$ denotes the rth cumulant of [*]. Note that if sample estimates are used, the above holds exactly for the first two cumulants by virtue of Gram-Schmidt orthogonalization. If the hypothesis is accepted on the basis of the available sample estimates, then equation (A1) may be rewritten in terms of the orthogonalized, and hence "independent", random variables $\tilde{R}_i$, $\tilde{R}_y$.

Suppressing for simplicity the time argument of the transformation coefficients, and letting $X_i = \sum_j X_{ij}$, we have

$$
\begin{aligned}
\tilde{Y}^*(t) = {} & \\
& \tilde{R}_1 * [-\tilde{X}_1 - a_{21}\tilde{X}_2 - a_{31}\tilde{X}_3 - a_{41}\tilde{X}_4 - \cdots + a_{y1}] \\
+ & \tilde{R}_2 * [\qquad\quad - \tilde{X}_2 - a_{32}\tilde{X}_3 - a_{42}\tilde{X}_4 - \cdots + a_{y2}] \\
+ & \tilde{R}_3 * [\qquad\qquad\qquad - \tilde{X}_3 - a_{43}\tilde{X}_4 - \cdots + a_{y3}] \\
& \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \\
+ & \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \\
& \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \quad \cdot \\
+ & \tilde{R}_I * [\qquad\qquad\qquad\qquad\qquad\qquad - \tilde{X}_I + a_{yI}] \\
+ & \tilde{R}_y \qquad\quad - b_2\tilde{X}_2 - b_3\tilde{X}_3 - \cdots - b_I\tilde{X}_I + b_y
\end{aligned}
\qquad \text{(A3)}
$$

As long as some $a_{ij}(t)$, or $b_i(t)$, $j = 1, \ldots, m$, is non-zero, the terms being summed in (A3) are not independent since X_i appears in more than one term. Denoting by i^* the subgroup of NDT associated with a non-zero $a_{ij}(t)$ or $b_i(t)$, and conditioning on the value of $\tilde{X}_k$, $k \in i^*$, equation (A3) takes the form of a sum of independent random variables. Then, using the probability theory results stating that

- the moments of a product of independent random variables are equal to the product of the moments of each variable
- the cumulants of a sum of independent random variables are equal to the sum of the cumulants of each variable
- cumulants are a known polynomial function of moments and vice versa,

equation (A3) yields the cumulants/moments of $\tilde{Y}^*(t)$ conditional upon values of $\tilde{X}_k$, $k \in i^*$. The unconditional moments are subsequently derived by summing and weighing the conditional ones. Thus, denoting the rth moment by m_r,

$$m_r[\tilde{Y}^*(t)] = \sum_{\substack{\text{all values of} \\ \tilde{X}_k,\ k \in i^*}} m_r[\tilde{Y}^*(t)/\tilde{X}_k] * \text{Prob}(\tilde{X}_k) \qquad \text{(A4)}$$

Finally, the moments/cumulants of $\tilde{Y}^*$ are obtained by summing the moments of $\tilde{Y}^*(t)$ and weighing by the relative length of each time of day category t, denoted by Prob(t).

$$m_r[\tilde{Y}^*] = \sum_t m_r[\tilde{Y}^*(t)] * \text{Prob}(t) \qquad \text{(A5)}$$

APPENDIX B

CALCULATION OF DERIVATIVES OF $\tilde{Y}^*$ CUMULANTS

The computation of the derivatives of $\tilde{Y}^*$ cumulants with respect to installed capacity x is outlined below. First, some definitions are given below assuming a Gram-Charlier series up to eight cumulants.

- m[*] = 8 x 1 vector of first eight moments of [*].
- k[*] = 8 x 1 vector of first eight cumulants of [*].
- kM[*] = 8 x 1 vector whose elements are polynomials of the moments of [*] relating them to the first eight cumulants of [*].
- Mk[*] = 8 x 1 vector whose elements are polynomials of the cumulants of [*] relating them to the first eight moments of [*].
- e_i^T = 1 x 8 transposed vector of zeroes with 1 as its ith element.

Consider now the case with one NDT generation option, since the extension to many is straightforward. Equation (A3) becomes after dropping index i,

$$\tilde{Y}^* = b + a\tilde{R} + \tilde{R}_y - \tilde{R}\tilde{X} = b + \tilde{R}[a - \tilde{X}] + \tilde{R}_y$$

Following the procedure in Appendix A we have:

$$k(\tilde{Y}^*) = kM[\sum_t m[\tilde{Y}^*(t)]P_t]$$

$$m[\tilde{Y}^*(t)] = Mk\ [k(b) + k[\tilde{R}(a - \tilde{X})] + k[\tilde{R}_y]]$$

$$k[\tilde{R}(a - \tilde{X})] = kM\ [m[\tilde{R}]\ m[a - \tilde{X}]]$$

$$m[a - \tilde{X}] = Mk[k(a) + k(-\tilde{X})]$$

Applying the chain rule we obtain an expression for the desired derivatives with respect to installed capacity x:

$$\frac{\partial k(\tilde{Y}^*)}{\partial x} =$$

$$\frac{\partial kM[\tilde{Y}^*]}{\partial m[\tilde{Y}^*]} \left\{ \sum_t P_t \left[\frac{\partial Mk[\tilde{Y}^*(t)]}{\partial k[\tilde{Y}^*(t)]} \; \frac{\partial kM[\tilde{X} \,.\, \tilde{R}]}{\partial m[\tilde{X} \,.\, \tilde{R}]} \sum_{i=1}^{8} m[\tilde{R}] e_i^T \cdot \frac{\partial Mk[a - \tilde{X}]}{\partial k[a - \tilde{X}]} \cdot \frac{\partial k[-\tilde{X}]}{\partial x} \right] \right\}$$

In the above expression notice that $m[\tilde{X} \,.\, \tilde{R}] = m[\tilde{X}] \,.\, m[\tilde{R}]$ and that $\frac{\partial kM[*]}{\partial m[*]}$, $\frac{\partial Mk[*]}{\partial k[*]}$ are 8 x 8 lower triangular matrices with elements i, j being the derivates of the ith cumulant as a function of 1, 2, ... ith moment with respect to the jth moment and vice versa, respectively. Finally, observing that the moments of $\tilde{X}$ are explicit functions of the nameplate capacity of X, the expression above can be evaluated as a function of the known nameplate capacity.

REFERENCES

[1] Baleriaux, H., E. Jamoulle, and F. Linard de Guertechin, "Simulation de l'exploitation d'un parc de machines thermiques de production d'electricite couple a des stations de pompage," Revue E, vol. V., No. 7, 1967, pp. 225-245.

[2] Bloom, J. "Long-Range Generation Planning Using Decomposition and Probabilistic Simulation," IEEE Trans. on Power Apparatus and Systems. Forthcoming, presented at the 1981 Summer Power Meeting.

[3] Booth, R.R., "Power System Simulation Model Based on Probability Analysis," IEEE Transactions on Power Apparatus and Systems, Vol. PAS-91, January/February 1972, pp. 62-69.

[4] Bright, R., Davitian, H. "Application of WASP to the Analysis of Solar and Cogenerating Technologies in the Context of PURPA," Conference Proceedings on Electric Generating System Expansion Analysis, March 1981, Mechanical Engineering Dept, The Ohio State University.

[5] Finger, S. "Electric Power System Production Costing and Reliability Analysis Including Hydroelectric, Storage, and Time Dependent Power Plants," MIT Energy Laboratory Technical Report No. MIT-EL 79-006, February 1979.

[6] Geoffrion, A.M., "Generalized Benders Decomposition," Journal of Optimization Theory and Applications, Vol. 10, No. 4, 1972, pp. 237-260.

[7] Jenkins, R.T., Joy, D.S., "Wein Automatic System Planning Package (WASP)," ORNL-4945, Oak Ridge National Laboratory, July 1974.

[8] Kendall, M. and Stuart, A. The Advanced Theory of Statistics, Volume 1, MacMillan Publishing Co., Inc., New York, 1977.

[9] Stremel, J.P. "Production Costing for Long-Range Generation Expansion Planning Studies," IEEE Trans. on Power Apparatus and Systems. Forthcoming, presented at the 1981 Summer Power Meeting.

[10] MIT Energy Laboratory, "Electric Generation Expansion Analysis System, A Progress Report on RPI 1529," MIT-EL 80-020, June 1980.

ACKNOWLEDGMENTS

Research reported in this paper was supported jointly by the Department of Energy National Photovoltaic program under Contract No. EX76-A-01-2295 and EPRI Power System Planning and Operations program within the Electrical Systems Division under Project RP1529. The work in RP1529 was carried out under the direction of Dr. Neal Balu of EPRI. The industry advisors on RP1529 and three anonymous referees provided valuable, constructive comments. Responsibility for any errors remains with the authors.

Chapter 4

Photovoltaic Market Analysis: Background, Model Development, Applications and Extensions

Gary L. Lilien, Frank H. Fuller

1.0 Introduction

The purpose of this chapter is to describe and motivate the market analysis research and development efforts for photovoltaics that have developed over the last several years. The main objective is to develop tools and procedures to help guide government spending decisions associated with stimulating photovoltaic market penetration.

This chapter presents the theoretical and empirical support for a market assessment and analysis process aimed at providing decision support for the DOE PV program. The process has three main components: (1) theoretical analyses, aimed at a qualitative understanding of what general types of programs and policies are likely to be most cost-effective in stimulating PV market penetration; (2) an operational model, PV1, providing an interactive, user-oriented tool for quantitative study of the relative effectiveness of specific government spending options, and (3) field measurements aimed at providing objective estimates of the parameters for PV1 model analysis.

The PV1 model is used to determine allocation strategies for constrained government spending that will most stimulate private sector adoption of photovoltaics over time. By comparing the model's market penetration forecasts for different strategies, government policy analysts can compare the effects of those strategies quantitatively.

Motivation for the model is provided in Sections 2 and 3. Section 2 summarizes what is known about diffusion processes, concentrating primarily on models of the consumer adoption process and on those factors that influence the rate of adoption. Section 3 reviews other solar-energy diffusion models and demonstrates that a need exists for a more realistic, data based approach to modeling diffusion phenomena.

Unlike other models of solar diffusion, PV1 is integrally linked to empirical data. Most importantly, PV1 models diffusion rates implicitly, through a consumer-based choice model, rather than through an exogenously defined diffusion function as do earlier models. Section 4 presents the PV1 approach in detail. The section begins with a discussion of the problem, describing the government policy options available for photovoltaics. The structure of the model is then justified theoretically and empirically.

A unique characteristic of the PV1 approach is that it is tied to a field data collection activity. Section 5 motivates that data collection process, linking it to parameterization of the PV1 model.

Section 6 discusses some theoretical results on the optimal deployment of demonstration program and subsidy program resources. These results apply not just to PV, but to many new technologies that are governed by diffusion processes and experience curve cost declines and economics of scale. They provide insight into the kinds of policies that government should find most cost-effective.

Section 7 presents PV1 analyses of 15 different government support strategies. The theoretical results on optimal policy spending strategies are compared with the quantitative results of the model.

The modeling and data collection procedure has led to a number of observations that can be made that are specific to photovoltaics. These are collected and summarized in Section 3. In that section possible extensions to the model are described, and the value of using this approach for other technologies is discussed.

2.0 Background on Market Penetration of New Technologies

An understanding of the adoption process of a new technology is key to the development of a good market penetration model. There are two reasons for this: first, it is necessary to specify the important stages of the adoption process for the new technology; second, those factors that influence movement between the adoption process stages and that ultimately affect the rate of market penetration must be identified and quantified.

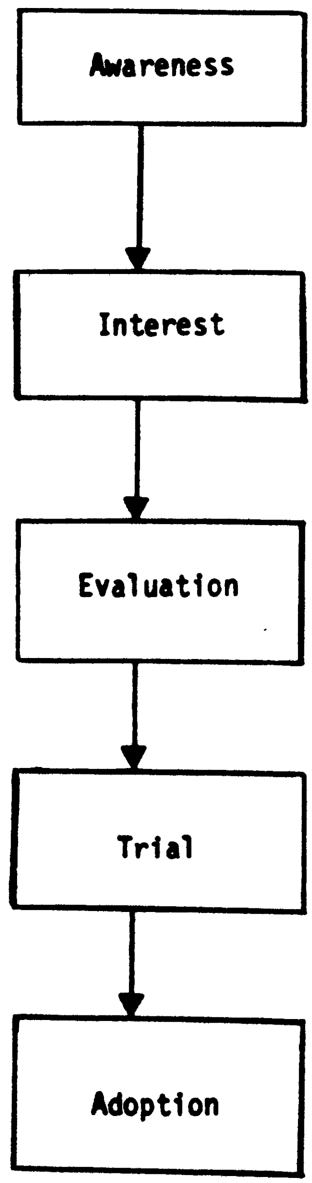
Significant differences exist between the adoption processes of individual and industrial consumers. In industry, as in the commercial, agricultural and central power sectors, adoption is an organizational decision. As such, the adoption process in these sectors is substantially more complex than it is at the individual, home-owner level. Despite differences in complexity, individuals and organizations in general follow many of the same steps toward eventual adoption. This section first examines the individual adoption process, commenting on differences between individual and organizational procedures. The factors that influence the rate of adoption are then described and categorized.

2.1 Stages in the Adoption Process of New Technologies: Individual

Researchers differ a bit in their delineations of the new technology adoption process for individuals, but a five-stage process suggested by Rogers [1962] is a typical classification. This process, diagrammed in Figure 2.1, is applicable both to durable and non-durable products, but

Figure 3.1

The Individual Adoption Process



Source: Rogers, 1962

for durable goods, stages 4 and 5 are collapsed, there being no distinction between trial and adoption. The characteristics of the five stages give insight into the adoption process.

The Awareness Stage

In this initial stage the potential adopter learns of the existence of the new technology but possesses little information about it. Awareness may result either from purposive seeking of information by the potential adopter who has a need for the benefits of a new product or technology, or, as most researchers believe, from the individual coming into random contact with information about the new technology.

The Interest Stage

Here, the potential adopter develops interest in the innovation and actively seeks information about it. His personal values combined with social norms will play a part in determining where he seeks information and how he uses this information. The same is true for the organization, where one or more individuals develop an interest in an innovation and then begin to search for information.

The Evaluation Stage

When the potential adopter enters the evaluation stage he has collected enough information about the innovation to come to a decision. He considers all information that is important to him, weighs the advantages and disadvantages of the innovation and makes his decision to adopt or not to adopt. At this stage the advice of peers is sought while the impact of mass communications, important in the awareness and interest stages, becomes secondary.

The organization, unlike the individual, usually has a formalized set of evaluation criteria on which to judge new product adoption, especially for capital expenditures. Certain minimum requirements, for payback or warranty period, e.g., are used to screen out unacceptable products or projects. Evaluation for organizations is most often undertaken by a combination of individuals.

The Trial and Adoption Stages

For durable products the trial and adoption stages are synonomous. The potential adopter purchases the innovation and uses it. He forms either a favorable or unfavorable impression of the innovation. In the organization, the person who decides to adopt or reject the innovation may or may not be the person who searches for information or the one who makes the in-depth evaluations. Several individuals may combine their judgments in different ways in the final decision process.

Roger's model is not entirely satisfactory because it assumes that all potential adopters will eventually adopt an innovation and also neglects to include a post-adoption stage in which an innovater may participate in promoting or alternatively, criticizing, the innovation. In a revised, but non-operational model, Rogers takes account of these phenomena.

In the case of photovoltaics, the residential homeowner is an individual adopter. Lilien and Johnston [1980], however, in an analysis of active solar heating and cooling studies, suggest that the residential new home-buyer, because of interactions with builders, architects, and HVAC contractors in the decision to adopt solar, is involved more in an organizational-type than an individual adoption process, although more of an individual-type purchase occurs for retrofit installations. Thus, the more formalized evaluation procedures of builders and contractors will become part of the evaluation process when PV is the innovation considered.

Diffusion theory focuses on the last stage of the model, the adoption stage. Nevertheless, an understanding of how people move through the successive stages of the adoption process is needed to model innovation diffusion over time. To understand how people move through the process it is necessary to understand consumer behavior and the concept of consumer innovativeness.

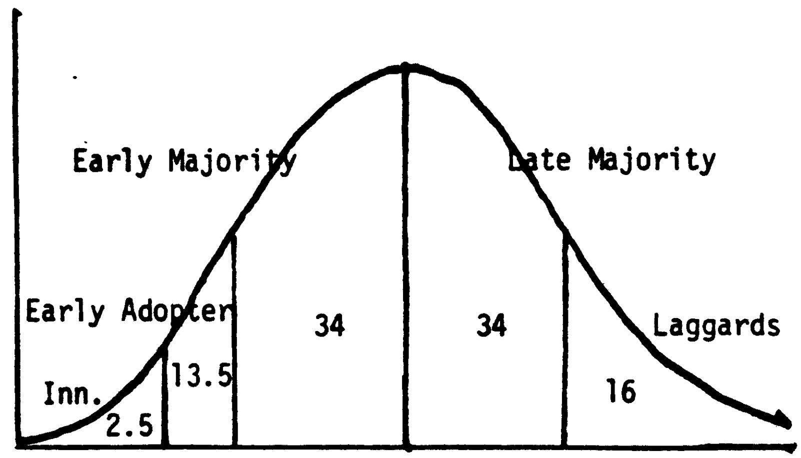
2.2 The Consumer Innovativeness Model

Rogers and Shoemaker [1971] have defined consumer innovativeness as "the degree to which an individual is relatively earlier in adopting an innovation than other members of his system." They have quantified this concept by categorizing all individuals in five groups according to each individual's degree of innovativeness. Figure 2.2 shows Roger's categorization scheme, based on a normal distribution, with the proportion of individuals in each category appearing in each section of the curve. Marketers in general have chosen to accept Roger's categories as useful but have not endorsed the absolute categorical proportions. In fact, much research has been conducted in trying to determine the size of the innovator category for different products: innovators are considered the key to many new products' successes.

Early adopters enter the market after seeing the product is performing acceptably. "Early majority" buyers then follow, again waiting to see how the product performs. If the innovation proves itself among "early majority" people then the product has a good chance of success. A period of strong demand then ensues generated by the "middle majority." Demand tapers off and finally the "laggards" purchase [Ryan, 1977]. There will of course always be a group of non-adopters. Plotting

Figure 3.2

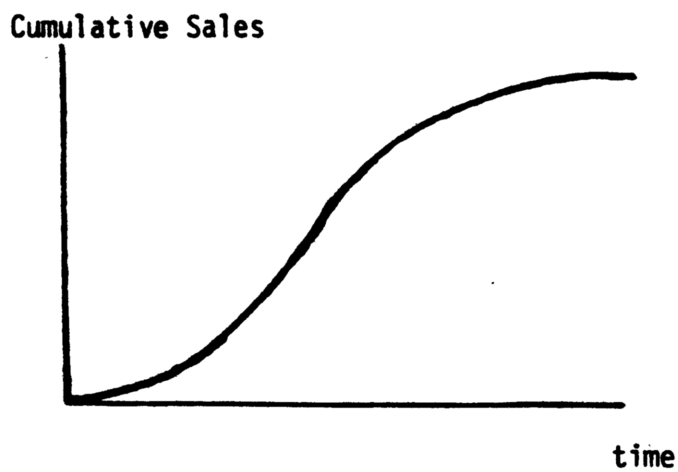
Roger's Adopter Categorization Scheme



Source: [23]

Figure 3.3

The Time Path of Diffusion



cumulative sales of the innovation against time, the diffusion process just described takes the S-shape shown in Figure 2.3. Researchers have studied many mathematical functions with the S-shape property in an effort to forecast sales over time. Results are far from perfect. Generally, there is little prospect of knowing beforehand the relative sizes of the buyer categories.

Although the evidence is far from conclusive, individual innovators tend to be cosmopolitan, read more and travel more [Ryan, 1977]. It is thought that innovators seek new products with a "new, first, original, futuristic, distinctively different" image [Midgley, 1977]. Laggards on the other hand seem to be risk averse, willing to accept only proven products.

The consumer innovativeness model is too simplistic. It places people into five buyer categories irrespective of the product innovation in mind. Furthermore, it categorizes individuals based primarily on their degree of risk aversion to something new, disregarding other potentially important factors which must be considered in the evaluation stage of the adoption process model. In spite of these faults, the consumer innovativeness model does emphasize two important points that must be considered in a market penetration model: (1) many individual consumers wait to see how well a product performs before making a decision to adopt, and (2) there is an underlying distribution of how many other consumers must find the product satisfactory before a given consumer will consider adoption. For innovators, the number of previous purchases is small; for laggards it is very high.

2.3 Factors which Influence the Rate of Diffusion

The rapidity with which a new technology diffuses into the marketplace depends on how the innovation is perceived at the individual or micro level. The individual, in his decision to adopt or reject a new technology, weighs the benefits and drawbacks of the innovation within a framework of personal and social structure values [Bernhardt, 1972]. Product, personal and social characteristics blend together to influence a potential adopter's overall perception of the innovation. This perception may be distorted either by the manner in which the individual perceives the innovation or by ineffective or misleading communication from those marketing the new technology. From a marketer's standpoint, effective communication of those product attributes that satisfy both individual and social needs is key to improving product perceptions with the resultant increase of an individual's probability of adoption.

Unfortunately, the determinants of adoption are not standard across new technologies. Nevertheless, Zaltman and Stiff [1973], in an analysis of Fliegel and Kivlin's work [1966], categorize a set of common issues or factors that influence the rate of adoption, and, therefore, the rate of diffusion. The list is not exhaustive, nor does each factor listed pertain to all new technological innovations. They point out, moreover, that each innovation may exhibit unique characteristics that also significantly affect diffusion rates. Such appears to be the case with photovoltaics. After presenting a categorization of factors common across most new technologies, we discuss some unique factors affecting the rate of diffusion of photovoltaics.

2.3.1 Common Diffusion Factors

The factors that affect the rate with which potential adopters move through the adoption process are different for each stage.

Awareness: Awareness is created by mass communications such as advertising and public relations. For the later adopting segments, observation of innovation usage and word of mouth are important conveyors of awareness. The individual tendency to expose oneself only to those mass communications that reinforce one's opinions, and to ignore those one does not agree with is an important effect which limits awareness. (This process is called selective exposure.)

Interest: In the interest stage the individual collects information. If information is readily available from many sources, he moves through this stage quickly. If information is sparse, of the wrong kind or difficult to access, then movement through the interest stage is slow.

Evaluation: In the evaluation stage, the consumer weighs the relative advantages of the innovation with those of alternatives. The potential adopter decides on the relevant criteria along which to evaluate the innovation, the criteria chosen specific to the purpose of the product and the needs of the potential adopter. Several criteria are commonly used in evaluating an innovation. These include:

1. Financial criteria: These criteria may be grouped in two categories--costs and returns. Costs may be further broken down into initial and continuing costs. Fliegel and Kivlin [1966] in a study of farm practices, found that while continuing costs have a negative partial correlation with the adoption rate, initial costs have a positive partial correlation. Zaltman and Stiff hypothesize that the unexpected positive correlation may be explained by a cost-quality relationship in which innovations of high initial cost are perceived as high-quality products. They state that these higher-priced innovations will primarily be durable goods that are purchased infrequently. Apparently, the perceived extra quality more than compensates for the extra cost. It seems likely,

however, that durable goods are also prone to incurring higher continuing costs than nondurable goods, so it is not clear whether durability will have an overall positive or negative effect on the rate of adoption. There is no basis for generalizing these results from the agricultural sector to the residential, industrial, and other sectors, although it is important to recognize both initial and continuing costs in studying diffusion.

The concept of return in some ways captures the cost dimension since it can be used to determine when costs are recovered. Return is a loose term used to describe both payback and return on investment. Financial return can be, and is, measured by many different methods, among then net present value, discounted payback and simple payback. In industry, many companies use several return criteria to evaluate a product. Most individuals rely more on simpler concepts, like simple payback. Short paybacks and large returns on investment will speed up adoption.

2. Social criteria: Again, there are costs and returns. Social costs inhibit the adoption rate by keeping potential adopters from purchasing for fear of social ridicule. It seems that social costs borne by a potential adopter are partially determined by social position. High-status individuals and marginal members of groups may find themselves the least penalized for adopting, the former because they can afford to be innovative and will suffer little if wrong, and the latter because they have nothing to lose and everything to gain.

Social returns were found to be small in the Fliegel and Kivlin farm study although this may not follow in general.

3. Efficiency: A potential adopter evaluates an innovation in terms of its efficiency, that is, how much time the innovation saves and how much

discomfort it can alleviate. These can be important evaluation dimensions for innovations dealing with household operation and maintenance.

4. Risk: The risk of an innovation is measured by the innovation's perceived regularity of reward and its divisibility for trial. An innovation that can be trial sampled on a small scale is inherently less risky than one that cannot be trial sampled. The less divisible for trial, the lower an innovation's adoption rate.

The perceived regularity of reward is positively correlated with an innovation's adoption rate. If the reliability of an innovation is poor, then the regularity of reward will be perceived as erratic, uncertainty will be high and the adoption rate will suffer.

5. Communicability: Communicability deals with the ability to effectively convey perceptions to potential adopters. The more complex the innovation, the more difficult it is to convey those perceptions that will positively affect the rate of adoption.

6. Compatibility: If the innovation is not compatible with existing systems, and requires significant adjustments on the part of a potential adopter, then the speed of diffusion will be slowed.

7. Perceived Relative Advantage: The unique attributes of an innovation that are not possessed by the traditional alternatives are key influences on the rate of adoption. The more important these attributes to the potential adopter, the more rapid the rate of adoption. If these attributes are especially visible, perhaps even demonstrable, then the innovation is more likely to diffuse quickly.

2.3.2 Diffusion Factors Unique to Photovoltaics

Photovoltaics is a complex technology. The installation of a PV array requires competent and trained workmen. It is improbable that, in the first years of PV diffusion, workmen skilled in PV installation techniques will be available everywhere to service anyone who wants a PV array. The diffusion of PV will therefore be slowed by distribution and service factors. Also contributing to diffusion problems will be transportation limitations of shipping PV arrays from geographically separated manufacturers to potential adopters.

If comments about the esthetics of active solar systems are applicable to photovoltaics, then diffusion will be hampered in the residential sector by individuals who think PV is unattractive. Jerome Scott [1976], in a study of homeowner attitudes toward active solar systems, found that on average, an individual would be willing to pay up to $2000 more to have a collector installed on the back instead of the front of his house.

Finally, the rate of PV diffusion will vary markedly between the new and retrofit markets (mainly residential). Since new homes can be constructed with a south-facing roof, new homeowners are more likely potential adopters than existing homeowner-retrofit customers, whose roofs often do not face due south. Furthermore, it should be easier for a new homeowner to incorporate the cost of the PV installation in his long-term mortgage than it would be for a retrofit installer to obtain favorable financing.

3.0 Modeling Approaches in the Solar Energy Area

As Section 3 showed, the factors affecting the rate of diffusion are both varied and complex. No diffusion model exists that captures all relevant diffusion phenomena. Still, even an incomplete model can provide insight into how a product will diffuse, and for some of the simpler diffusion problems, reliable analyses of market penetration can sometimes be produced. The completeness of a model will determine how useful the model can be to the user. To build a "good" model, the modeler must strike a balance between theory, data and the intended use of the model.

This chapter reviews four major solar diffusion models, ending each review with a discussion of model problems. The model reviews are made in the context of how well the models represent the diffusion phenomena described in the previous chapter. Evaluation of the models occurs at several levels.

3.1 Criteria for Evaluation

Lilien [1975] suggests that models should assume different levels of complexity depending upon the use as well as the user. For example, a model aimed at sales forecasting for the purposes of inventory control may be adequate for the operations department, but useless for the advertising department, interested in advertising evaluation.

Little [1970] discusses some criteria for evaluating models. To be useful, he suggests a model should be:

- simple--understandable to the user
- robust--absurd answers being difficult to obtain
- easy to control--amenable to manipulations that provide easy analysis of model sensitivity
- adaptive--capable of being updated as more data become available
- complete--including all the most important variables
- easy to communicate with.

All the models we will review here make explicit or implicit trade-offs in these criteria. It will be shown that other solar diffusion models have not incorporated sound diffusion principles and are in this sense incomplete. Yet, a complete model, one that incorporates all important diffusion phenomena and is as "true" as possible, may not be capable of being tested or used: the data required to estimate its parameters may be either unavailable or difficult to generate. Clearly, as we move to more complete models, we will have more data, estimation and interpretation problems.

We now review four solar penetration models. These models are the Arthur D. Little (ADL) SHACOB model [1977], the MITRE Corporation's SPURR model [1977], the Energy and Environmental Analysis (EEA) MOPPS model [1977] and a model by Stanford Research Institute (SRI) [1978].

3.2 Evaluation of Solar Penetration Models

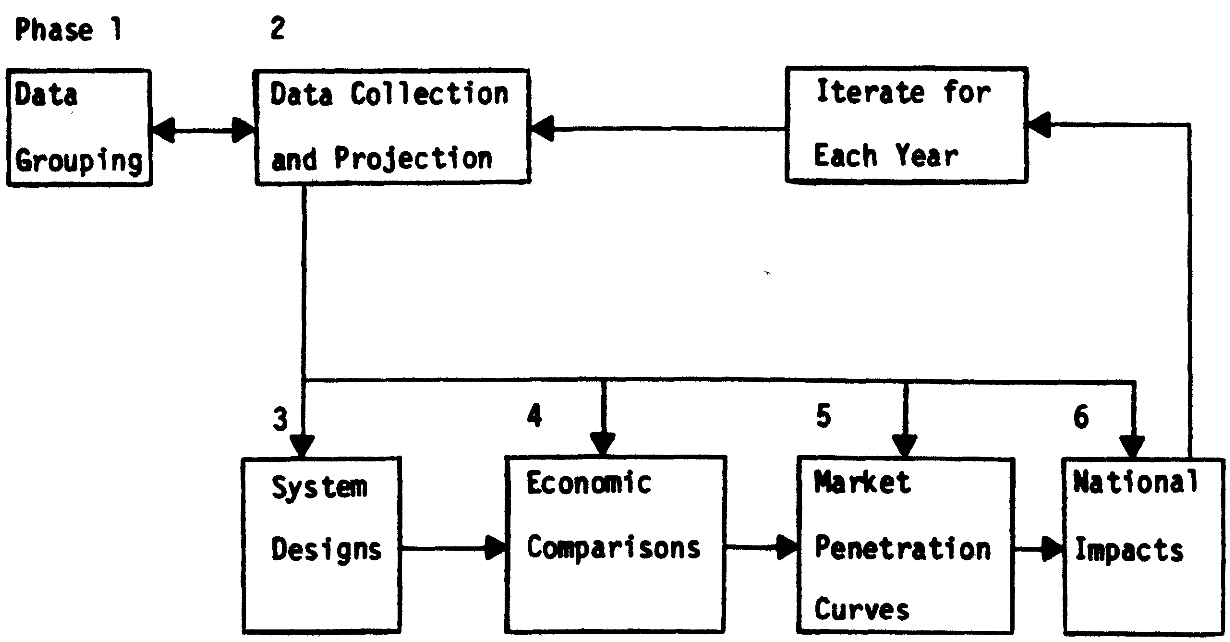
The models reviewed in this section deal with different aspects of alternative energy technologies. For instance, the ADL model only addresses the market penetration of solar heating and cooling technologies while EEA's model deals with solar as well as with non-solar energy technologies. Nevertheless, the same diffusion phenomena should, in general, be applicable to most of the new, durable alternative energy technologies.

Schiffel et al. [1977] point out that each of the four penetration models here reviewed has six basic components. Figure 3.1 illustrates the relationships of these six components. The following is an abbreviated summary of Schiffel's description of the six phases of the penetration models.

1. Phase 1: In Phase 1 the relevant market is divided into geographic regions usually on the basis of insolation and climatic conditions. The

Figure 4.1

Basic Components of Most Solar Energy Market Penetration Models



Source: [Schiffel, 1977, pg. 8]

market is then segregated into a number of building types with different characteristics that might influence eventual adoption. The four models reviewed all deal with building characteristics. Next, the types of energy technologies considered by a model are classified. These technologies include solar hot water, solar heating, wind and many more. The SRI model considers over 20 solar technologies.

2. Phase 2: Data are collected in Phase 2 and a means for projecting changes and future levels of data variables is devised. The data are collected by geographic region for such variables as insolation, fuel costs, market sizes and growth rates.

3. Phase 3: In this phase, an idealized average installation size is calculated by region. An estimate is made of the percentage of the annual energy load that could be supplied by the solar system.

4. Phase 4: Projections of future fuel prices, population growth rates, solar technology prices and energy usage are made. Comparison evaluations are then made between conventional and solar energy sources.

5. Phase 5: An exogenously defined market penetration curve is specified. This curve takes the familiar S-shape. The curve uses parameters based on the economic comparison evaluations of Phase 4 to model diffusion. The purpose of the penetration curves is to show how potential adopters react to the relative economics of solar versus conventional energy.

6. Phase 6: Sales of the solar technology are calculated. The models then recycyle back to Phase 1 for another year in the forecast.

All models reviewed below have this basic structure.

3.2.1 The ADL SHACOB Model

The SHACOB model is used to evaluate the effect of federal solar incentive programs on the growth of solar hot water, space heating and space heating and cooling systems in the residential and commercial sectors. The model takes federal incentives as input to calculate total collectors sold, the percentage of the market penetrated and the cost to government of the incentive programs.

The basic unit of analysis of the SHACOB model is a geographic region broken down both by market and building type and new or retrofit application. SHACOB differentiates 10 building types. Market penetration is calculated for each solar technology for each unit of analysis and is aggregated to provide estimates of annual solar penetration by region. Penetration is estimated in a three-step process:

1) Cost of the solar system is retrieved from SHACOB data base
2) Payback period is calculated
3) An exogenously defined function with an S-curve shape uses the payback period as a parameter. Market sales are read off the curve.

To account for non-financial factors that can influence the rate of diffusion, SHACOB uses a weight (called UTIL) between -1 and 1 to modify the payback up or down. Positive UTIL's accelerate diffusion while negative UTIL's slow diffusion down. The determination of the UTIL value is arbitrary.

SHACOB incorporates learning curve cost declines at both the national and regional level in its determination of solar system prices. Furthermore, as cumulative production increases, potential adopters' likelihood of purchase is assumed to increase, the result of an hypothesized greater acceptance of solar as a reliable alternative energy source.

Problems with SHACO3: The ADL model has three major problems. First, the use of an arbitrarily defined S-curve function imposes preconceived notions of how diffusion of the solar technology will play out over time; the possible paths that diffusion can take are limited by the modeler's choice of an S-curve function. Second, the use of the UTIL weight is arbitrary and there is no empirical correspondence between the size of the UTIL weight and the positive or negative influences of many factors that can affect the diffusion rate. Third, although it seems reasonable that the likelihood of purchase will increase over time as cumulative sales increase, there is no empirical justification for how SHACO3 determines just how large the increase should be.

3.2.2 The MITRE SPURR Model

SPURR is a simulation model that uses a database of energy costs, engineering costs and data for different possible future economic scenarios to assess the impact of fuel costs, energy demand and government incentive programs on market acceptance of solar energy products. The model forecasts penetration for three major sectors:

1) buildings (hot water, heating and cooling)
2) process heat (agricultural and industrial)
3) utility.

We focus on sector 1 here. The buildings component is divided into nine building types for new and retrofit systems. Market potential is determined by building type, within 15 specified regions and for several electricity-using conventional systems.

Market penetration is calculated using an arbitrary hyperbolic tangent function that produces an S-curve shape. The function has several parameters, among them a "figure of merit" (FOM) which is an index of the relative competitiveness of the new technology. For one and two family residences, FOM is a function of initial cost and annual savings but for other building types the functional form changes.

SPURR incorporates learning curve cost declines in its cost formulation of the solar product.

Problems with SPURR: In using an exogenously-defined S-curve function, SPURR has the same problem as SHACOB. There is no attempt to calibrate the SPURR model with empirical results from the field, which means that the diffusion path predicted by SPURR is an artifact of the S-curve function chosen by the modeler.

3.2.3 The EEA MOPPS Model

The MOPPS Model is comprehensive, and examines the potential of all new energy technologies in the industrial sector. The model attempts to match energy technologies to appropriate markets. It does this by segmenting the industrial sector by two-digit SIC codes and then further segmenting by service sectors. The result is over 2000 industrial market segments. MOPPS measures characteristics of each of these segments and attempts to match them with one of the new technologies.

Having thus defined the market, MOPPS describes new technologies (descriptions provided by ERDA) in terms of optimum plant size, initial costs, operating costs and data of commercial availability. Technologies that fit in with more than one service sector are described separately for each sector. The idea is to match the needs of a sector with the assets of one of the new technologies.

Next, market penetration is calculated. New technology sales are found in a three-step process:

1) First, the proportion of the market in a given segment that

finds a technology cheaper than other technologies is determined. This value is known as the "nominal market share."

2) Second, a penetration percentage of the total market is found using an S-curve function, with relative rate of return between old and new technologies and historical innovativeness providing the S-curve parameters. The penetration percentage is multiplied by the "nominal market share" to obtain an effective penetration rate.

3) Third, using estimates of industry growth rates, the potential market size is projected by multiplying the effective penetration rate by the potential market. Total penetration is found by aggregation over each segment over each technology.

Problems with MOPPS: The model assumes that financial aspects are the only relevant factors influencing diffusion. The absence of a risk factor in the specification of MOPPS undermines its validity. And, again, the use of an exogenous S-curve function to describe diffusion is suspect.

3.2.4 The SRI Model

The SRI model forecasts solar market penetration for every five-year period from 1975-2020. It provides analyses of seven solar energy technologies in nine regions. Model analysis considers three supply/demand scenarios:

1) low solar price

2) high electrification, high demand

3) high non-solar price.

To develop market penetration results, SRI estimates base case energy demand and price for 25 end-use markets using a basic scenario from the

SRI National Energy Model. The end-use markets considered are those where solar technololgies are competitive (e.g., water heating, space heating). Over 20 different generic solar systems are looked at (including 3 photovoltaic systems). Cost estimates are developed for each solar design.

Economically viable solar technologies are compared with conventional energy sources in the residential/commercial, industrial and utility sectors. Market penetration estimates for each viable solar technology are determined by the relative prices of solar and conventional energy sources as well as by a "gamma parameter." The "gamma parameter" is a value intended to measure a wide range of diffusion rate influencers such as price variations, resistance to change and consumer preferences. Gamma is used to parameterize an S-curve function which is in part specified by a behavioral lag. To specify the behavioral lag function the user subjectively estimates a date by which time it is felt that 50 percent of the market will respond to the introducton of the new technology. Once gamma and the behavioral lag are known the diffusion path assumes a fixed form.

Problems with the SRI Model: The use of the gamma parameter as an index for all non-financial diffusion factors has no theoretical basis. The relative importance of the different factors that go into gamma can only be guessed at. The behavioral lag function is also subjectively determined, but it does not mix several unrelated diffusion phenomena as does the gamma parameter. As with the other models it uses an arbitrary, exogenously-defined S-curve function to model penetration.

3.3 Conclusions

Models of solar market penetration have, in the past, inadequately addressed diffusion principles. By relying on overly simplified, representations of diffusion phenomena, these models have failed to capture many of the important phenomena described in Section 3. The MOPPS Model incorporates financial aspects of a new solar technology but nothing else. Issues such as level of awareness, distribution, technical risk and esthetics are not considered. It is apparent that the MOPPS model suffers from incompleteness.

The most serious problem with the penentration models reviewed is the exogeneous specification of an S-curve for diffusion. This approach sets diffusion paths arbitrarily by specific functional forms that may bear little relation to reality. Furthermore, the parameters used to calibrate the S-curve are often meaningless mixtures of different diffusion factors. Neither are these parameters tied to empirical data; instead they are subjectively developed.

It appears, then, that a viable approach for PV is (a) to try to incorporate diffusion phenomena specifically in a model, (b) let the diffusion process dictate the diffusion path over time and (c) relate model parameters to data. This approach is developed next.

4.0 The Structure of the PV1 Model

The primary weakness of previous market penetration models for solar energy systems has been their failure to incorporate sound diffusion principles. By using exogenously-defined arbitrary S-curve functions to predict the time path of market penetration, these models capture only their modelers' pre-conceived notions of what the time path of sales should look like. Warren [1979], in a review of the most widely known solar energy market penetration models (MITRE (1977), SRI International

(1978), Arthur D. Little (1977), Midwest Research Institute (1977), and Energy and Environmental Analysis (1978)), concludes that "... solar energy market penetration models are not science, but number mysticism. Their primary defect is their penetration analyses which are grounded on only a very simple behavioral theory." Warren contends that a good market penetration model must begin with an adequate model of consumer adoption behavior.

The PV1 model is an attempt at explicitly modeling the consumer adoption process in the context of a market penetration model. A second difference of of the PV1 model from other penetration models is that it has an empirical base: the PV1 model relies on a large data base of demographic and behavioral information. PV1 links a consumer adoption process model with a data base, thereby erecting a model structure built on diffusion concepts that are independent of an externally specified functional form.

PV1 is a model written in the PL/1 programming language that forecasts market penetration of photovoltaics over time. It is an interactive model, allowing a user to specify technological information about photovoltaics, and to allocate funds to government policy options, as input. In turn, PV1 provides forecasts of costs of photovoltaic cells, sales of photovoltaic systems in peak kilowatts and total government program costs. The usefulness of the PV1 model is that it gives a user the ability to simulate a range of government policy options. Comparison of resulting PV1 model forecasts affords a basis for evaluation of the effects of various policies on diffusion. The evaluation of these effects can give government policy makers a clearer picture of the diffusion process and a better feel for deploying government funds in ways which will most stimulate market penetration.

This section describes and motivates the evolution and development of the PV1 model. The structure of the model is then justified theoretically and empirically. As background for the model development we first define the major government policy options available in the National Photovoltaic Program.

4.1 Government Policy Variables

There are five classes of policy variables that the government is most concerned about in the photovoltaic area: subsidy, technology development (TD), market development (MD), advanced research and development (AR&D), and advertising (ADV). All five affect both the cost and acceptability of PV in the private sector. Subsidy is the only policy option funded through channels other than the $1.5 billion available to the National Photovoltaic Program.

Subsidies: As modeled in PV1, government subsidy policy consists of establishing a subsidy rate which is the fraction of the PV system cost that the government will bear. The amount the government subsidizes an individual installation is assumed to be limited by a subsidy ceiling. Subsidies directly reduce the cost of a PV system, thereby shortening the payback period for a purchaser.

Market Development (MD): Market development is government spending allocated to the purchase and (usually) subsequent installation of PV systems at selected demonstration sites. MD purchases act to accelerate the market penetration of PV by demonstrating PV as a successful energy alternative. In addition, MD purchases have two major impacts on costs: government purchases (in addition to private sector purchases) lead to greater production quantities and, hence, to lower balance of system

(BOS) or non-module costs; MD spending also supports the marketplace for arrays, and the greater that spending the more efficient the production facility and the lower the array cost. This latter impact can be substantial for the high volume production required of current silicon technology. With advanced silicon technology, however, JPL analyses (1980) suggest that plants will most likely be built at economic size, so MD spending will not affect array price once advanced silicon technology comes on line.

Advertising (ADV): The government allocates funds to advertising--information dissemination--in order to increase awareness of PV within the potential market. Government advertising will concentrate on promoting PV as an alternative source of electricity. A second, costless component of advertising is the advertising value of a visible government-supported PV installation.

Technology Development (TD): Technology development spending is money earmarked for development of production processes that can meet PV program goals. By effecting early reductions in PV module costs, TD spending can shorten the time until PV program goals are met. The reduction in module prices is projected to occur in at least three stages. The current stage is called the "intermediate" technology stage, a stage when module costs are still quite high. As TD money is spent, module costs are reduced until no further reductions are possible without a technology change. PV is currently entering a second stage, from which the rate of decline in costs can largely be influenced only by advanced research and development spending.

Advanced Research and Development (ARHD): Money allocated to ARHD is directed to those research endeavors with potential for breakthroughs in technology, perhaps of a non-silicon variety, and which are expected to have significant, long-term cost reduction capabilities. Greater spending in ARND is assumed to shorten the time to development of a breakthrough technology. Thus, ARND spending acts to shorten stage two of the module cost technology, thereby hastening the arrival of stage three and the breakthrough technology. DOE has set a module cost goal of $.70 per peak watt by 1986 for a breakthrough technology.

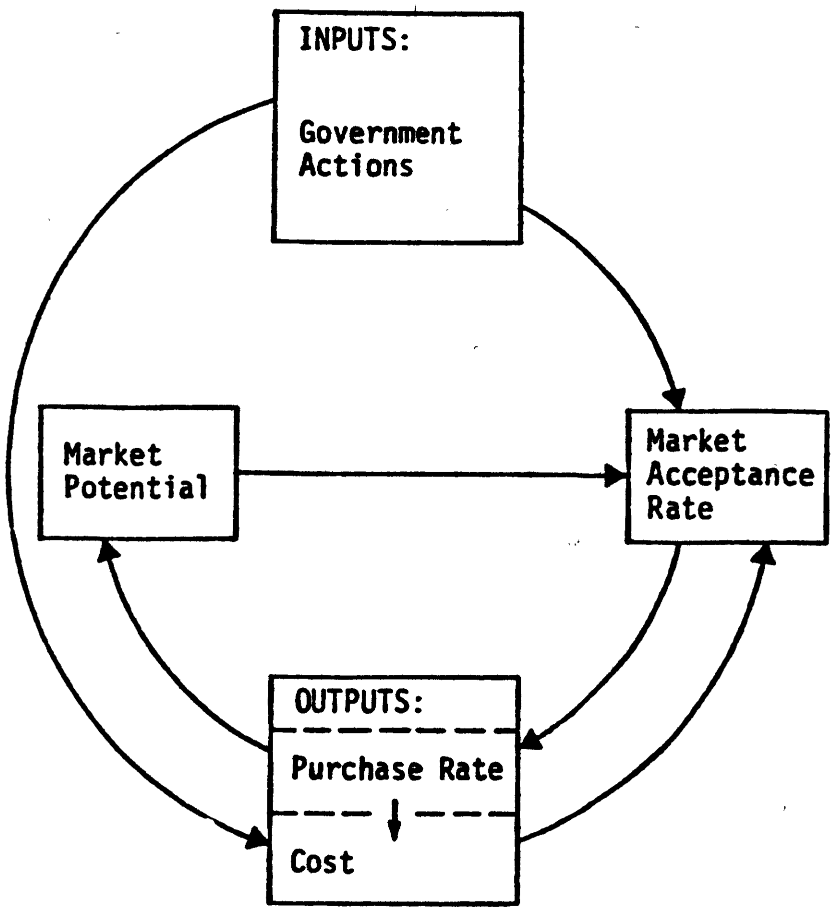
4.2 Overview of the PV1 Model Structure

Figure 4.1 describes the basic conceptual structure of the PV1 model. The PV1 user first specifies an Input Model which defines technological information about PV as well as government policy actions. In addition, the user specifies the number of years for which the model is to forecast PV sales. In each year of the forecast, PV1 calculates a market potential for PV as shown in the Market Potential box. PV1 takes this market potential and reduces it in the Market Acceptance Rate box by screening out potential adopters who find the PV product unacceptable. Government actions, defined by user inputs, such as price subsidies and market development spending, make PV more acceptable in the market by 1) lowering the price to the user, 2) making consumers more aware of PV and 3) instilling confidence in PV as a technically and financially viable energy technology. Once the fraction of the total market who find PV acceptable is calculated, PV1 applies an exogenously defined probability of purchase (given that the product is found acceptable) to arrive at a final purchase rate in the Output box. PV sales feed back into the calculation of market potential in the following year of the forecast.

The Market Acceptance Rate box houses PV1's model of the photovoltaic

Figure 5.1

Conceptual Structure of PV1



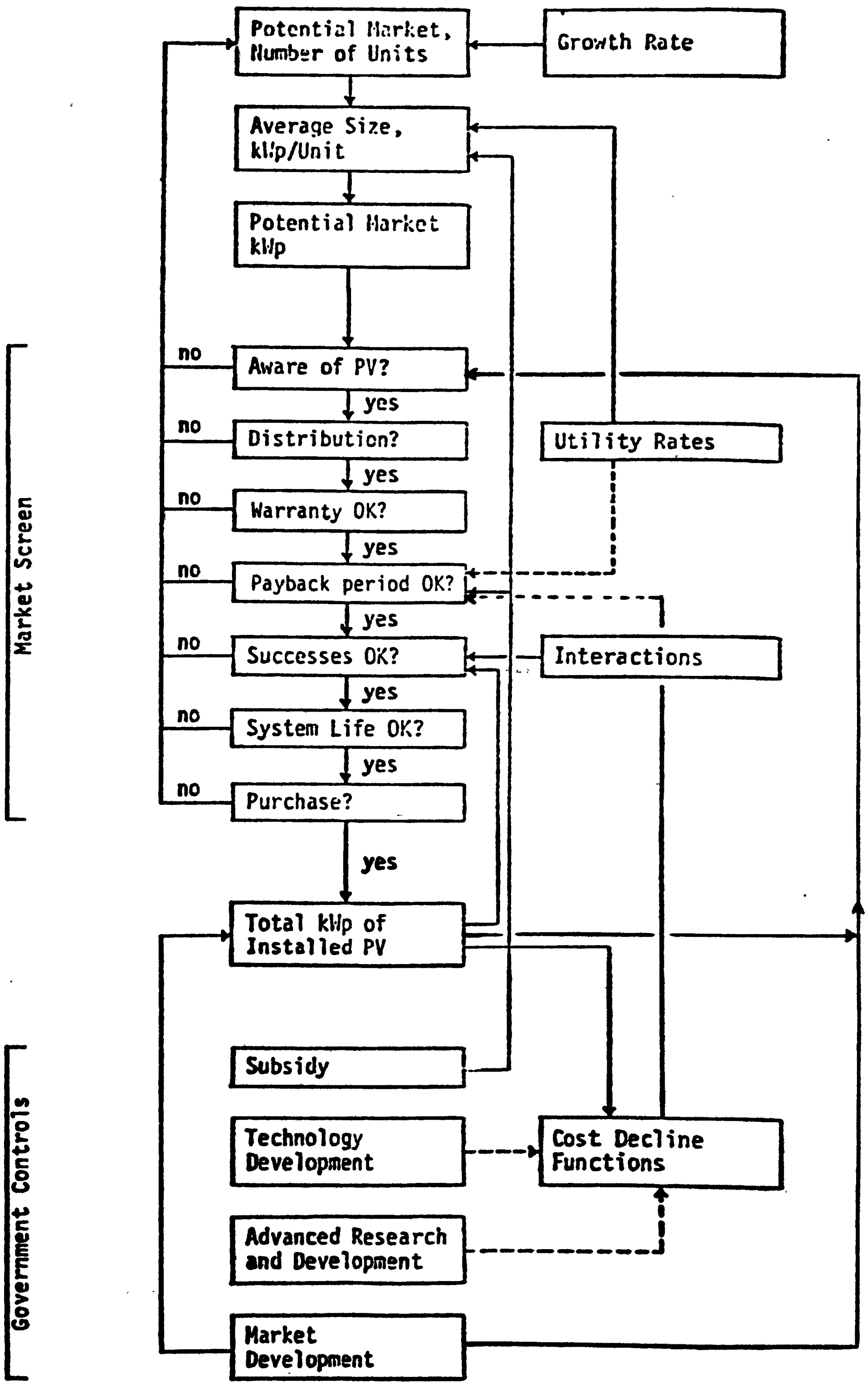
adoption process. In this box, potential photovoltaic adopters advance through the awareness, interest and evaluation stages discussed in Section 3. The modeling of the awareness stage is discussed in detail in Section 4.3c. Briefly, the awareness of potential adopters is assumed to be affected by advertising and market development installations. In each year of the PV1 forecast, some fraction of the market potential will be made aware of PV. The unaware fraction is screened out at the awareness stage of the adoption process. Those who are made aware proceed to the interest stage.

PV1 handles interest by assuming that information about photovoltaics is accessible to potential adopters, and therefore presents no barrier to adoption. Consequently, PV1 allows all who pass the awareness stage directly into the evaluation stage.

The evaluation stage is the heart of the PV1 model structure. In this stage of the adoption process potential adopters judge PV by comparing it to their current source of electricity, almost always a utility. They make comparisons along a number of dimensions, particuarly financial and risk attributes. Each dimension represents a stumbling block to final acceptance of the PV product. For a potential adopter to accept PV, he must find PV acceptable on each dimension. (The relevant dimensions are discussed in 4.3d.) PV1 models this process using a sequential ordering of market screens, one for each relevant dimension. At each market screen PV1 calculates the fraction of the remaining market potential which still finds PV acceptable. Figure 4.2 illustrates the procedure.

As mentioned earlier, the PV1 model is intimately bound to a large data base. This data base contains information necessary to perform many

Figure 5.2 - PV1 Model Structure



of the calculations in the market screen phase of the PV1 model. These information requirements impose one last structural constraint on PV1, a constraint which necessitates the fragmentaton of the market potential calculation into a large number of smaller market potentials. These become the basic units of analysis for the PV1 model. Each is the market potential of a sector within a region, or a sector-region. Operationally, these terms are defined as follows:

Region: A region refers to a utility district when that region is

(a) contiguous and

(b) within the boundaries of a single state

Thus, PV1 treats a utility district that provides power in two non-contiguous areas as two regions.

Sectors: The term sectors refers to functionally different PV usage groups that, because of differences in methods of production and installation of PV arrays, see different financial costs associated with PV. The six sectors explicitly included in the PV1 model structure are residential, commercial, industrial, agricultural, government/institutional and central power.

Market potential must be calculated at a regional level because local phenomena such as insolation and marginal electricity rates are required for the market screen calculations, calculations which directly influence the relative acceptability of PV. The PV1 regional data base supplies the information needed for these important calculations. PV1 treats the non-contiguous areas of a utility district as separate regions to account for possible differences in insolation values and to limit the effects of government market development installations between non-contiguous regions when they are separated by a substantial distance.

Referring once again to Figure 4.1, PV1 iterates through the diagram for each utility region within each sector for each year of the model forecasts. All major retail utilities in the United States (except Alaska) are included in the data base on which PV1 operates.

4.3 The PV1 Database

Information on 469 private, public and cooperative utility regions is stored in the PV1 data base. This information is broken down sectorally. Included in this data base is information on number of customers, average annual electricity usage, marginal electricity rates, population growth rates and insolation for each sector within each region. In forecasting annual market penetration, PV1 sequentially calculates PV sales in each of the 2812 sector-regions (6 sectors x 469 regions).

The PV1 data base contains only baseline values. For instance, the "number of customers" values are 1978 figures. Clearly these figures change over the duration of PV1 forecast periods. PV1 adjusts these numbers by applying a population growth rate to them for each year of the forecast period. The population growth rate recorded for a sector-region is an eight year average (1971-1978) of the total population growth rate for the state in which the utility region is located. It is recognized that growth rates should vary both regionally within a state as well as sectorally, and more accurate growth rate figures will be accessible once 1980 Census figures become available.

4.4 Justification of the PV1 Model Structure

The logic of the PV1 model begins with the total potential market in each sector within each region and reduces this market through market screens to derive a value for market penetration. The primary output of the model is a projection of the annual sales in peak kilowatts of installed PV by sector, aggregated over regions. The overall model logic for the calculation of PV sales is summarized in Figure 4.2.

4.4a Market Potential

The annual PV market potential in each sector-region is derived from the "number of customers" value stored in the PV1 data base. Using a sectorally determined average PV installation size, in square meters of array, PV1 converts the number of customers into a market potential in peak kilowatts. For the commercial, industrial, agricultural and government/institutional sectors, PV1 assumes that the average size of a PV installation is 300 square meters. The selection of this value is somewhat arbitrary, and was chosen as a best estimate of the needs of an average non-residential building or farm. As PV1 is developed, the average installation size will be modeled to more accurately reflect electricity needs in these sectors.

There are two underlying assumptions in the computation of average size in the residential sector. First, the total cost of electric energy for a PV user will be the user's cost of electricity before installing PV, plus the annualized cost of owning a PV system, minus the savings derived from both the reduced usage of utility energy and the savings derived from selling back any excess power produced by the PV unit. Second, it is assumed that the average residential PV user will purchase the PV array size that minimizes the cost of electric energy on an annual basis.

The average size of a residential PV installation is estimated by Lilien and Wulfe [1980] as:

$$W_m = \frac{AU \cdot ER \cdot (1 - R_s/R_p) \cdot b}{VC \cdot (1 + Z) \cdot CRF - R_s/R_p \cdot ER \cdot I \cdot \eta} \qquad (4.1)$$

$$10 \leq W_m \leq 90$$

where:

AU	= average annual electricty use, in KWh/yr
ER	= cost of utility generated electricity in $/KWh
R_s/R_p	= price of sell-back electricity as a fraction of purchased electricity
b	= regression constant = .1224
VC	= variable system costs, $/m^2
CRF	= capital recovery factor = .1175
I	= insolation, KWh/m^{2}yr
η	= system efficiency
Z	= system maintenance costs (annual fraction)
W_m	= average size, m^2

For the central power sector, it is assumed that a utility will only purchase PV if it has a need for at least 25 MWp of additional capacity. The average installation size for central power is arbitrarily set at 25 MWp/η.

The need to put market potential in units of peak kilowatts stems from the standard practice of pricing PV in dollars per peak kilowatt. The conversion of one square meter of installation size into peak kilowatts assumes the form:

$$KW_p = \eta(m^2) \quad \text{where } \eta = \text{system efficiency (about .12)} \qquad (4.2)$$

Thus an average industrial PV array of 300 m^2 will produce approximately 36 peak kilowatts. And the total market in a sector-region in a given year is computed as:

$$KW_{srt} = A_{srt} * V_{srt} \tag{4.3}$$

where:

KW_{srt} = the potential market in peak kilowatts, in sector s, region r, at time t

A_{srt} = average PV installation size in m^2, in sector s, region r, at time t

V_{srt} = number of potential customers in sector s, region r at time t

It is assumed that all planned capacity increases for a utility region (less whatever photovoltaics are installed by utility customers) plus the replacement of existing equipment, together represent the potential market for photovoltaics in the central power sector.

Once market potential has been calculated, the fraction of the market who find PV acceptable is found by successively reducing the market potential through a series of screens. The first screen encountered in PV1 is the awareness screen.

4.4b The Awareness Screen

The potential market in a sector-region is first reduced at the awareness stage of the adoption process. The PV1 awareness screen eliminates potential buyers who are not aware of photovoltaics. The fraction of the current market that is aware of PV in year t is the sum of:

(a) the fraction of the market who were aware of PV in year t-1 and who remember it; and

(b) the fraction of the market who were not aware of PV in year t-1 but who are informed of PV in year t.

Awareness of PV within the potential market is a function of government advertising campaigns, measured in terms of effective advertising dollars that the government spends annually. There are two sources of "effective advertising dollars":

1) Direct advertising dollars which government spends on media and information dissemination. In PV1, this kind of government spending is user specified as a fraction of MD spending.

2) Non-monetary advertising. A government purchased market development installation is assumed to have advertising value for demonstrating that PV is viable both technically and economically. The advertising value of a demonstration installation is set at $3000. Private PV installations also have this value.

Thus:

$$EAD_{srt} = ADPER_t * MD_{srt} + DELTA * \sum_{k=1}^{S} CUMSITES_{kr} * SI_{ks} \qquad (4.4)$$

where:

EAD_{srt} = effective advertising dollars in sector s, region r at time t

$ADPER_t$ = fraction of MD spendng in time t used for direct media promotion

MD_{srt} = market development spending in sector s, region r at time t

DELTA = effective advertising value of a visible PV installation (in dollars). PV1 uses a value of $3000 for DELTA.

SI_{ks} = the effective perceptual influence of sector k on sector s. (This variable is described in 4.3c.)

Assuming that the potential market is made aware of PV only by "effective advertising dollars", the fraction of the market aware of PV in year t is given by the following simple model of advertising awareness:

$$A_{srt} = K * A_{srt-1} + (1 - K * A_{srt-1}) * (1-e^{-(EAD)B}) \quad (4.5)$$

where:

A_{srt} = fraction of potential market aware in sector s, region r at time t

K = memory constant. Of those who were aware in time t-1, K is the fraction who remember in time t. In the current version of the model, K is set at .75.

B = 1[illegible]

EAD = effective advertising dollars

The coefficient B is estimated by assuming that one half of an average regional market is made aware of PV when total regional "effective advertising dollars" are $50,000.

4.4c The Market Evaluation Screens

The fraction of the potential market that successfully passes through the awareness screen next enters the evaluation stage of the adoption process. PV1 subjects the remaining market to four market evaluation screens which further reduce the fraction of the market who find PV acceptable. These screens deal with technical, warranty, system life and payback acceptabilities. In a national study of Active Solar Heating and Cooling Products [1980] these screens were found to be the primary evaluation criteria used. The active solar systems studied are products that share many technological and economic attributes with PV. The marked similarities of these other solar products to PV suggested that the same evaluation criteria could be successfully applied to the PV case.

PV1 handles the logic of the market screen evaluations as demonstrated in the following example of the warranty screen.

Warranty

The PV1 user may specify the warranty period (W) for PV in the Model Inputs. Otherwise, the PV1 default value is 12 months. First, PV1 asks the question, "What fraction of potential adopters would find PV unacceptable if the warranty were less than (W) months." The answer to this question is provided by survey results used in generating a distribution of the fraction of the market who find PV unacceptable for a range of warranty period values. The distribution is sector dependent, so a separate distribution is required for each of the six sectors. For example, in the residential sector the percentage who find a 12 month warranty to be unacceptably short is 74 percent. This figure drops to 22 percent for a three-year warranty. The same procedure is taken for the other three evaluation screens. The distributions of these unacceptabilities are built into the PV1 model. It is computationally fortunate that these screening distributions for each sector were empirically found to be independent of one another. This allows the PV1 market reduction algorithm to process the criteria sequentially rather than jointly: if, for instance, a potential market is evaluated at 1,000,000 peak kilowatts, and awareness is 36 percent, warranty acceptability is 26 percent, lifetime acceptability is 63 percent, technical acceptability is 5 percent and payback acceptability is also 5 percent then the total market of those who find PV acceptable is:

$$1{,}000{,}000 * .36 * .26 * .63 * .05 * .05 = 147 \text{ peak kilowatts}$$

System Life

As with the warranty, the PV1 user may specify the expected lifetime (L) of the PV system in the Model Inputs. Default is 15 years. PV1 then calculates the fraction of potential adopters who would find PV unacceptable if the expected system life were less than (L) years.

Technical Acceptability

This screen assesses the innovativeness of potential adopters as well as the purchase-risk proneness of potential adopters. For this screen PV1 determines the fraction of potential adopters who would find PV unacceptable if they had not seen at least (I) PV installations already operating successfully. An important implicit assumption here is that all PV installations operate successfully: the PV1 model does not account for negative word-of-mouth effects from PV field failures. These effects will be modeled in a future revision of PV1. (See Kalish and Lilien, 1980, for preliminary work on this problem.)

The determination of the number of prior successful installations is handled by modeling interaction effects.

Interactions: The six sector types have different influences on each other which we define as sectoral interaction effects. It is hypothesized that PV systems installed in one sector influence the effective number of successful installations perceived by potential adopters in other sectors. In addition, the distance of installations from those potential adopters perceiving them should also influence the number of effective installations that are perceived. Thus, the effective number of installations perceived by potential adopters within a given sector and region is equal to the number of installations within that sector and region plus the effects of installations outside the sector or region. This is computed as:

$$EFF_{srt} = \sum_{n=1}^{R} \sum_{k=1}^{S} N_{srt} * SI_{ks} * RI_{nr} \qquad (4.6)$$

where:

N_{srt} = actual cumulative number of installations in sector s, region r, at time t.

SI_{ks} = the effective perceptual influence of sector k on sector s

RI_{nr} = the effective perceptual influence of region n on region r

EFF_{srt} = effective installations perceived in sector s, region r at time t

Both influence coefficients vary between 0 and 1 and PV1 assumes:

$$RI_{rr} = 1 \qquad RI_{nr} = RI_{rn}$$

and

$$SI_{ss} = 1 \qquad SI_{ks} = SI_{sk}$$

The default values of all other influence coefficients are 0. The PV1 user is free to redefine the SI coefficients.

Values of RI are computed on the basis of a gravity type model, where the interaction between two regions is inversely proportional to the square of the distance (in miles) between them:

$$RI_{nr} = \text{minimum}\left(\frac{d_0^2}{2d_{nr}^2}, 1\right) \tag{4.7}$$

where:

d_0 = distance at which interaction = 0.5

d_{nr} = distance between regions n and r, in miles

The PV1 database stores distances of a region's ten closest neighbors. Installations from these neighbors are used in calculating EFF_{srt}. Influences from all other regions are regarded as negligible.

Payback

PV1 calculates a simple payback for each sector-region for every year of the forecast period. The form of the payback calculation is:

$$\text{payback} = \frac{\text{system cost - subsidies}}{\text{pvsave + bbsave - mtncost}} \tag{4.8}$$

where:

pvsave = electricity savings (dollars) from using PV instead of the utility

bbsave = money earned from selling excess PV electricity back to the utility

mtncost = annual maintenance costs.

PV1 then determines the fraction of potential adopters who would find PV unacceptable if payback were more than (y) years.

An important assumption of the PV1 model is that all non-utility PV users install systems that are connected in parallel with the utility grid (that is, they use as much of their own PV power as they can, sell the excess to the utility, and purchase back-up power from the utility) and do not use storage systems These are called "parallel" distributed PV systems. Prices that are paid to the PV user for electricity sold to the utility in PV1 are consistent with rules set down by the Public Utility Regulatory Policy Act (P.L. 95-617, PURPA). Utilities are expected to pay between 30 and 70 percent of a user's marginal electricity rate for such electricty, in compliance with PURPA's "just and reasonable" rule. The variable "bbsave" in PV1 represents the savings to an average consumer from electricity sold back to the utility.

4.41 Market Distribution

The acceptance of PV as a viable alternative source of electricity is not enough to guarantee purchase. It may be, for instance, that in the early stages of marketing PV, manufacturers are simply unable to achieve total geographic distribution. The obstacle to distribution lies not with the shipment of PV equipment, but with the lack of competent local contractors and service personnel. Few such individuals are likely to emerge in small towns and rural areas. Limited distribution acts to screen out another fraction of potential adopters from purchase. To model the distribution screen, a survey of contractors and builder/developers in each utility region would be required. It would be necessary to assess each contractor and builder/developer's probability of learning PV installation techniques. For the current version (and with some reservation) PV1 uses an average nationwide distribution fraction and applies it to each utility region. At present this fraction is set at .5 and is constant for the duration of PV1 forecasts.

In an aggregate sense, (and PV1 is an aggregate model), the use of one overall distribution fraction is not unreasonable, provided of course that it is accurate. Although distribution will vary over utility regions, the aggregate of all regional market penetrations for a given year will be the same, using either the one average distribution fraction or 469 utility region-specific distribution fractions. Unfortunately, in using the average fraction, the PV1 model may incorrectly distribute installations over regions. In so doing, region-specific technical acceptability screen values (number of prior successful installations) are altered. It is not clear how much bias this introduces into market penetration forecasts. Furthermore, the distribution fraction should realistically increase over time as acceptability increases among contractors and builder/developers. In future revisions of PV1 an attempt will be made to estimate with accuracy an initial distribution fraction (.5 is only a best guess) and then to model the temporal distribution and shift of this fraction.

4.4e Probability-of-Purchase

The final step in the calculation of PV sales requires determining the fraction of the market who will buy, given they have passed through the previous awareness, evaluation and distribution screens. There is no known survey or statistical method which can estimate ex ante the probability-of-purchase with any reliable accuracy. Techniques commonly practiced for deriving a probability-of-purchase include measurement of purchase intentions of a sample group of potential adopters. Researchers generally apply some arbitrary factor to the purchase intention responses to arrive at an overall probability-of-purchase. Kalwani and Silk [1981] report that "while positive associations between intentions and purchases have generally been observed..., the strength of the relationship uncovered in these analyses has not been viewed as sufficiently marked and consistent to allay the basic concern ... [of] ... many in the marketing research community."

In the same paper Kalwani and Silk present further analyses of a method developed by Morrison [1979] to evaluate the quality of purchase intention measures. Part of the unreliability of estimating probability-of-purchase from purchase intentions is that purchase intention responses are measured with error. Morrison's model provides a framework for evaluating the effect of inaccurate responses.

The probability-of-purchase currently used in PV1 is a best-guess estimate of 10 percent, consistent with data on appliances given by Juster [1966]. The need exists for a better estimate. In the future, a survey to measure purchase intention for PV will be conducted, measurement error will be estimated using Morrison's model, and hopefully an adequate probability-of-purchase will be obtained.

4.4f Market Penetration

Market penetration in a sector-region is calculated by multiplying the fraction of the market who find PV acceptable by the distribution screen fraction and by the probability-of-purchase. Thus, in the example of the warranty screen section, market penetration would be:

$$147 \text{ peak Kw} * .5 * .1 = 7.4 \text{ peak Kw}$$

PV sales are fed back into the succeeding year to adjust downward that year's market potential estimate. In addition, PV1 updates the database values of acceptabilities for each evaluation screen, for each sector-region, by subtracting out the fraction who have bought. For example, if 10 percent of a given sector-region found a payback of 10 years or more acceptable and ultimately 3 percent buy in that year, then in the following year only 7 percent of the market would find a payback of 10 years or more acceptable. (This is modified somewhat for changes in market potential due to growth, etc.)

One last aspect of the PV1 model is the incorporation of a market expansion factor. If PV sales grow too quickly, such that expected production cannot keep pace with demand, then PV1 limits annual sales by proportionally scaling down sector-region sales until their sum equals some allowable total sales maximum. The market expansion factor is modeled such that in the long run, PV sales cannot grow more than 30 percent annually and can at most double eight years into the model cast. Functionally,

$$\text{market expansion factor} = .3 + 1.7 * \exp(-.11091 * t) \qquad (4.9)$$

Finally, a caveat for use of PV1 model forecasts is in order. As this section has demonstrated, PV1 forecasts are based not only on a number of measured quantities (for instance, the acceptability values) but also on several unknown quantities like the probability-of-purchase. Thus, the PV1 forecasts should not be studied in terms of absolute market penetration numbers. Rather, the major usefulness of PV1 is as a sensitivity tool, allowing a user to compare the likely diffusion of PV under different market stimulation policies.

4.4j Cost Reduction

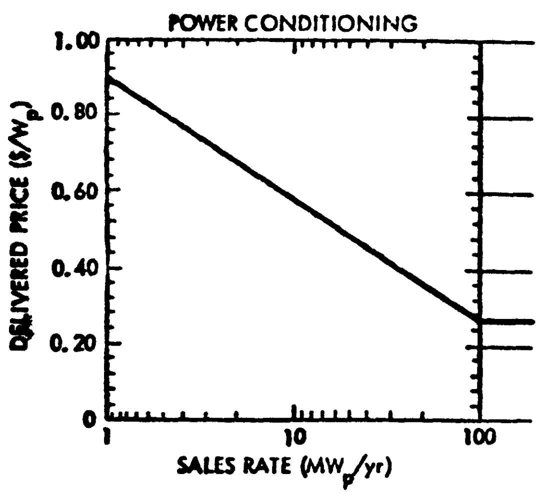
The costs of a PV installation figure prominently in several PV1 calculations, most importantly in the calculations of government subsidy costs and the payback screen. The diffusion rate, a function of the payback screen, is thus sensitive to the cost of PV. Although costs cannot be perfectly foreseen into the future, PV1 requires a cost reduction model that can give good estimtes of PV costs through the next decade. The reliability of PV1 output depends on the accuracy of this cost reduction model. PV1 uses the cost reduction formulation described below - a formulation designed to conform with methods suggested by JPL [1980].

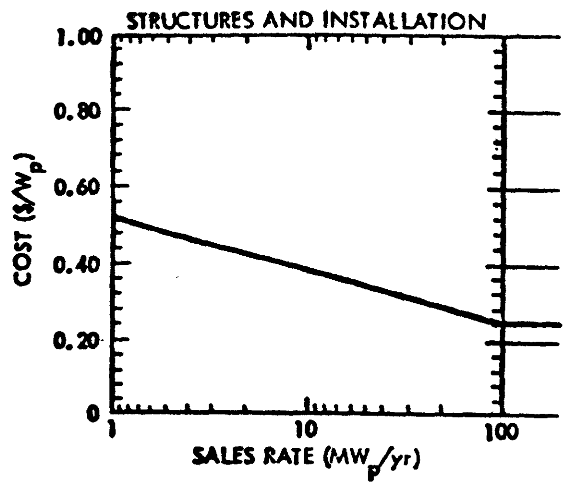
A PV installation has two main components: the PV module itself, and the balance of the system (BOS). BOS consists of power conditioning equipment, structures and indirect costs. Indirect costs are contingencies, fees and other costs not included elsewhere.

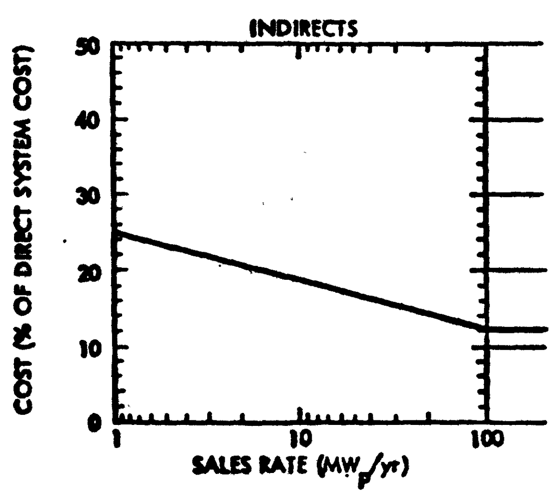
BOS Cost Reduction: BOS costs are assumed to vary from year to year, as a log-linear function of the total estimated annual sales rate. Specifications are illustrated in Figure 4.3. Just as there is interaction among sectors for the acceptability of the prior number of successful installations, the sales rate by which a sector's BOS costs are computed is also influenced by the number of sales in other sectors. In PV1, these sectoral influence coefficients can be user specified. The default values are those of the "successes" influence matrix, the matrix used in calculating effective successful installations for use in the technical acceptability screen.

Figure 5.3

Price/Cost vs. Sales Rate







Module Cost Reductions: The model for module cost reduction is more a function of the state of technology than are BOS costs, and is therefore more complex. It depends on government expenditures for technology development and advanced research and development, and on expectations about government and private purchases of PV. Module cost will also depend on the cost of silicon, the most probable future raw material for PV production. The cost is calculated in terms of dollars per peak watt.

The reduction in module prices is projected to occur in at least three stages. The date at which a new stage arrives is defined explicitly by the user, or optionally, the dates may be modeled, as shown below. The current stage is called the "intermediate" technology stage. In this stage, the price of PV is given by:

$$P_{MODULE} = [2.83 - (84 - P_{Si}) * \frac{94}{70000}] + \frac{2.4}{Z} \qquad (4.10)$$

where:

P_{MODULE} = price of PV, $\$/W_p$

P_{Si} = price of silicon, \$/kg

Z = plant size factor, MW_p/yr.

The plant size factor, Z, is the size of the plant, in MW_p annual production, required to produce 1/4 of the total MW_p purchased. (The PV1 model assumes a four plant industry for initial commercialization.)

The year that this first stage of module cost reduction ends may be defined by the user. Alternatively, the user may model the duration of the first stage by specifying the duration in terms of government technology development funding. PV1 estimates the duration through the following relationship:

$$T = (t_2 - t_0)\left[1 - \frac{X^\beta}{\gamma + X^\beta}\right] + t_0 \tag{4.11}$$

where:

T = time to end of stage 1,

X = cumulative TD in millions of dollars,

t_0 = earliest possible date for stage 2 after unlimited funds are spent,

t_2 = date of ultimate price if $X = 0$,

D_1 = most likely annual spending level

t_1 = most likely date for stage 2 at annual input spending level, D_1

t_3 = most likely date for stage 2 of module if annual spending level is $2D_1$.

and

$$\beta = \mathrm{Log}_2 \left[\frac{t_2 - t_3}{t_3 - t_0}\right] \left[\frac{t_1 - t_0}{t_2 - t_1}\right] \tag{4.12}$$

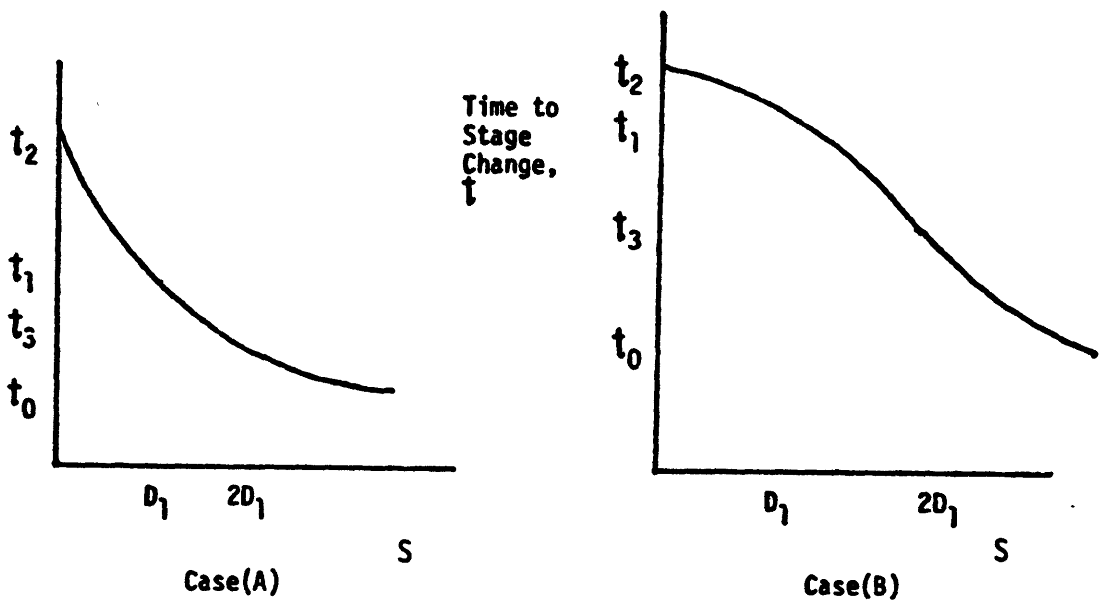
$$\gamma = (D_1 t_1)^\beta \quad \frac{t_1 - t_0}{t_2 - t_1} \tag{4.13}$$

The variables t_0, t_1, t_2, t_3, and D_1 are parameters supplied by the user as optional input. The amount of annual TD spending, D_1, is a control variable. The model itself will discontinue the allocation of TD in the year that Stage 2 technology arrives. Effects of the input parameters are illustrated in Figure 4.4.

The module price in the second stage is no longer a function of plant size, only of silicon prices. Plants are assumed to be producing at minimum efficient scale. Price in Stage 2 is modeled by:

Figure 5.4

Illustration of TD and ARND Spending Effects
on Technology Arrival Dates



S = Annual TD or ARND Spending

$$P_{MODULE} = 0.70 + [(P_{Si} - 14) * \frac{84}{7000}] \quad (4.14)$$

The date of the end of this second stage, called the "PV Program Goal" technology stage, will be a function of the ARND funding provided by the government. The functional form is identical to that defining the end to the intermediate technology stage:

$$T = (t_2 - t_0)[1 - \frac{Y^{\beta}}{\gamma + Y^{\beta}}] + t_0 \quad (4.15)$$

where Y now represents the cumulative level of ARND funding.

The third, or "ARND Breakthrough" technology stage, represents an ultimate, low price for PV that will result from some as yet unknown technology. While the date for the beginning of this stage may be computed by the methods outlined above, the actual price is supplied by the user. The PV1 default is $\$.70/W_p$.

Total Cost: Disregarding subsidies, the final cost to the consumer of a PV installation is the cost per peak watt, installed, times the number of peak watts in the array. The cost per peak watt, installed, is a function of module price, BOS costs and a manufacturer's markup.

$$\text{Total cost}/W_p = [P_{MODULE} * (1 + \text{markup}) + \text{pcucost} + \text{snscost}] * (1 + \text{indcost}) \quad (4.16)$$

where:

P_{MODULE} = module cost

pcucost = power conditioning cost

snscost = structures and installation cost

indcost = indirect cost fraction

markup = manufacturer's markup fraction

In a future revision of PV1, a revised JPL cost formulation will incorporate a cumulative sales effect into the module cost calculation.

5.0 Field Data Collection

A unique characteristic of the PV1 model is that it is tied to a field data collection activity. Data collected in field surveys are incorporated into the PV1 model for calibration of the acceptability distributions of the evaluation screens. This section motivates that data collection process, linking it to parameterization of the PV1 model. In addition, and unrelated to the model, this section describes how direct product development strategy guidance can be derived from the field measurement procedure. The design and implementation of surveys in the residential and agricultural sectors are described.

5.1 Motivation for the Data Collection Activity

In recent years, a large number of studies have reported on the causes of new product successes and new product failures (see Choffray and Lilien, 1980, for discussion). In general, their results point to a single cause as the most frequent reason for market failure or delay of market success in the new product area:

- the product developer is out of tune with the way customers perceive and evaluate the product.

Thus, for DOE's market development program to be successful, not only must PV costs be lowered, but perceptions and expectations of PV must be measured early to provide feedback that can be integrated into the product development process. These measurements of consumers' perceptions, expectations and attitudes toward PV can be made with the use of a field survey. Results of the survey can suggest areas for product improvement, or a need for better communication of product features that are poorly perceived.

As important as field measurement is to the development of a successful product, it is no less important as a means for calibrating a model that is expected to provide reliable forecasts of PV market penetration. Without a strong link to how customers actually perceive PV, the usefulness of the model would be seriously impaired. There are several major objectives that field measurement must fulfill if it is to gather information that can be incorporated into the PV1 model:

- o to measure changes in the level of photovoltaic awareness and attitudes toward PV on a region-specific basis
- o to measure the sphere-of-influence of a PV demonstration installation. (How are awareness and technical acceptability affected by distance from an installation)
- o to act as an identifier of demographic and behavioral characteristics of early potential adopters (innovators) of photovoltaics
- o to determine acceptability distributions for a set of important PV evaluation criteria
- o to provide design feedback from potential adopters so that the market development program can achieve maximum effectiveness.

To realize these objectives, field measurements must be obtained periodically so that changes in attitudes, perceptions and awareness can be monitored.

5.2 Measurement Approach

This subsection motivates the measurement approach taken for PV. Sampling designs are described for surveys conducted in the agricultural and residential sectors.

Useful results from surveys are only obtained when the survey design is made carefully and scientifically. It is necessary to be aware of, and to try to minimize, threats to validity of measurement results. Controlled measurement demands pre- as well as post-action measures to evaluate the effect of an activity. For ease of description of measurement experiments we use Campbell and Stanley's notation [1963] which defines O as an observation (attitude measurement) and X as a treatment of exposure (to an experiment). In the past, the typical solar study has been a no-control post-test only experiment:

$$X \quad O \tag{5.1}$$

Boring [1954] states that "such studies have such a total absence of control as to be of almost no scientific value."

A most popular design that adds control both for external effects and for internal validity is the pre-test-post-test control group design:

$$\begin{array}{llll} R & O_1 & X & O_2 \\ R & O_3 & & O_4 \end{array} \tag{5.2}$$

(where R refers to randomized assignment to groups). The effect of X (exposure to a demonstration site, for example) is read here as

$$(O_2 - O_1) - (O_4 - O_3)$$

where the subscripts refer to sample numbers.

A typical tracking study, used in advertising assessment for consumer products, uses a modified version of design (5.2), (5.2a):

$$\begin{array}{llll} R & O_1 & (X & O_2) \\ R & O_3 & & O_4 \end{array} \tag{5.2a}$$

Here, exposure to a site is self-reported. Such a design is threatened with biased misclassification ("Did you see X "), but careful separation of the probe for X-exposure and probe for O_2 during the interview can minimize this source of bias.

If we view X_i as a set of random stimuli occurring at different times to different segments of the public (X_i might include a midwest natural gas shortage, a Middle East embargo, the modification of solar incentives, etc.), it becomes clear that a design like (5.3)

Time				
t = 1	t = 2	t = 3	. . .	
O_{11}	O_{12}	O_{13}		
O_{21}	O_{22}	O_{23}		(5.3)
O_{31}	O_{32}	O_{33}		

must be in the field already to capture these effects. A post-survey (like (5.1)) to evaluate the effect of planned or environmental change has no scientific value.

Thus, a carefully designed, random sample must be in the field periodically to read the effect of uncontrollable events on changes in solar attitudes and awareness as well as to read the effect of the field experiment unit.

How should that survey be designed The normal tracking-study design would be:

	Time			
Area	t = 1	t = 2	. . .	
1	$R(X_{11}O_{11})$	$R(X_{21}O_{12})$	. . .	
2	$R(X_{21}O_{21})$	$R(X_{22}O_{12})$	. . .	
.	.	.		(5.4)
.	.	.		
.	.	.		

Here, separate random samples are developed at each time-point. Group averages can be compared, but changes in attitudes at the individual level cannot be measured because different individuals are involved. We propose a variation of (5.4) that alleviates this problem. In (5.5) we consider region only and use the superscript A, B, etc. to refer to cohort, or group studied.

$$\begin{array}{lll} \text{Time} = 1 & \text{Time} = 2 & \text{Time} = 3 \\ R\ O_1^A & & \\ R\ O_1^B & (X_2 O_2^B) & \\ & R(X_2 O_2^C) & (X_3 O_3^C) \\ & & R(X_3 O_3^D)\ \ldots \end{array} \tag{5.5}$$

Here, cohort B is remeasured at 2; cohort C is remeasured at 3, etc. The imbedded design:

$$RO_1^A \ldots R(X_2 O_2^C) \ldots R(X_3 O_3^D)$$

is identical with a single row of design (5.4); in addition, we have the important remeasurement of changes within a cohort: $O_2^B - O_1^B$, for example.

Our measurement approach assumes that the likelihood of adopting photovoltaics is a function of (a) system economics, (b) psychological perceptions of the system, (c) demographic/life style variables and (d) regional influence factors. A normal cross-section of observations can be used to calibrate an individual choice model.

Where we wish to read the <u>effect</u> of a demonstration site, however, we need remeasurements. The design proposed here allows us to measure and calibrate the following key model:

$$\text{Intent}_{it} = f(\text{Intent}_{i,t-1}, \text{Economics, Life Style, Site Exposure, etc.}) \quad (5.6)$$

where the above equation suggests that <u>changes</u> in intent to purchase are affected by likely exposure to the PV site. Note that the individual remeasurement modeled above, embedded in our research design, allows for modeling at the individual level.

The importance of modeling at the individual level follows from the observation that if you have 10 regions, then with design 4, you have 10 observations:

$$O_{i2} - O_{i1} = \Delta_i, \qquad i = 1, \ldots, 10$$

With individual modeling, you might have a natural sample of 1000-2000 observations. The additional degrees of freedom for estimation allow for much more modeling flexibility and development of more useful information.

An important point to reemphasize is that the (common) design (5.4) is embedded in design (5.5). All information available from (5.4) can be obtained from (5.5) plus much more resulting from evaluation of effects at the individual level.

Variations on (5.5) are possible where portions of the cohort are remeasured after varying lengths of time. This design is useful when wearout of various program-effects are being tested.

Note that design (5.5) also allows for controlled experimentation (via direct mail, for example) to random subsets of the group between the first and second measurement. The residential study, described shortly, incorporates the first column of design (5.5).

As a first step in the measurement process, we must develop and test measurement instruments. This involves the recognition of the important issues that need to be measured.

5.2.1 Issue Recognition and Questionnaire Design

The PV data collection activity is a three-stage process. First, we identify relevant issues that the field survey should address. This is accomplished by either a focus group interview or by a series of individual face-to-face interviews. Second, the issues developed in these interviews are discussed, and then developed into attitudinal, perceptual, behavioral and demographic questions and statements that are put together into a pilot study questionnaire. The pilot study is fielded with a small sample of the relevant population and results are checked for questionnaire design and wording problems or possible omissions. Third, the questionnaire is reworked to eliminate its problems and then fielded in a large-scale survey.

Since PV-related issues vary sectorally, different questionnaires have been administered to the different sectors. The two following examples describe how data have been collected in the residential and agricultural sectors.

5.2.1a Questionnaire Development for the Agricultural Sector

In 1977, a government-funded PV installation was officially opened in Mead, Nebraska. The array provided electricity to a small irrigation pump that supplied water to a cornfield on a University of Nebraska experimental farm site. PV is especially appropriate for this application since pumping for irrigation is needed most on days when solar energy is most abundant. The opening provided a prime opportunity to measure farmer attitudes and perceptions of PV both pre- and post-observation of the installation. In preparation for this, a questionnaire was developed which was designed to measure sector demographics, price-acceptance distributions, number of prior successes of an innovation before it is accepted as reliable, cost decline factors and energy usage and needs. Other areas of concern were also probed to identify issues that would assist in future demonstration designs in other sectors. Using an open-ended format, two project members conducted interviews in nearby Lincoln, Nebraska with individuals who were involved in and knowledgeable about farm management and irrigation practices. The people interviewed were:

1. A farm business writer, who also owned a small farm;
2. A large farm owner-operator;
3. A farm-extension county agent;
4. A farm machinery dealer;
5. A bank farm-loan officer;
6. An official of the Farm Bureau;
7. The Department Head of Agricultural Engineering at the University of Nebraska;
8. University of Nebraska Professor of Agriculture and Water Resources;
9. University of Nebraska Public Relations and Communications Editor in charge of the PV demonstration project;
10. Radio and TV station farm editors in Lincoln.

The issues that emerged from these interviews were developed into questions and perceptual statements for a pilot study questionnaire. The pilot study was tested among farm owners in Massachusetts and New Hampshire. The questionnaire was then modified and a final version prepared for large-scale data collection at Mead on opening day.

The sample design for the larger-scale agricultural sector survey provided measurements from three types of respondent:

1. Farmers who had not been exposed to the PV demonstration
2. Farmers who had just been through the PV demonstration
3. Farmers who were interviewed just before and just after seeing the demonstration.

The actual sample design is summarized as:

	Measurement	Demonstration	Measurement	Total
Group 1	0			104
Group 2		X	0	105
Group 3	0	X	0	87
				296

The study did not incorporate methods for periodic observation and remeasurement.

5.2.1b Questionnaire Development for the Residential Sector

Two focus group interviews were conducted in July, 1980. The first group was composed of ten participants: six women and four men. All were married homeowners living in several of the more affluent suburbs of Boston, Massachusetts. All participants had non-electric hot water and heating systems. The respondents were selected at random within their communities and were interviewed at a professional facility in Lexington, Massachusetts.

Mention of PV was carefully avoided at the beginning of the interview. Focus group members were guided into a discussion of solar energy. A questionnaire about PV was then introduced. The members completed the residential questionnaires and made suggestions for possible improvements. The questionnaire was modified to take account of potential problems and a pilot telephone survey was subsequently conducted in the same Massachusetts suburbs where the focus group members lived. A large-scale survey will be fielded shortly and sampling will be conducted according to the first column of sample design (5.5). The resulting survey instruments are included as Appendix 2.

5.3 Calibration of the Acceptability Distributions

Recall that technical, warranty, system life and payback acceptabilities were found to be the primary criteria used by potential adopters in evaluating the PV system. One objective of the PV field surveys is to collect data which yield acceptability distributions for these four market evaluation screens. The procedure taken to derive the acceptability distributions is straightforward. For example, in the agriculture survey farmers were asked to specify their minimum requirements for system life, payback period, and number of prior successful installations they would have to see before considering a photovoltaic-powered irrigation system. (At the time of the survey, warranty was not considered an important evaluation criterion. A second study measured minimum requirements for warranty.) From their responses, cumulative acceptability distributions were derived: thus we look up for any given value of a parameter, the proportion of farmers who find the level of the evaluation criterion aceptable. The cumulative distributions are incorporated into the PV1 model. Should future studies find these distributions changed, then the current distributions will be replaced.

Acceptability distributions for the residential, commercial, industrial and public authority sectors are currently determined from information supplied in interviews with HVAC consultants and architects (Lilien and Johnston, 1980). These individuals estimated the acceptability distributions for each sector, and averages of their estimates were used as the distributions for PV1. The residential study soon to begin will supply PV1 with new distributions for the residential sector.

In sum, there were a number of field-related sources for the data incorporated in the PV1 model. The supporting data are found summarized in Lilien and McCormick, 1979 and Lilien and Johnston, 1980.

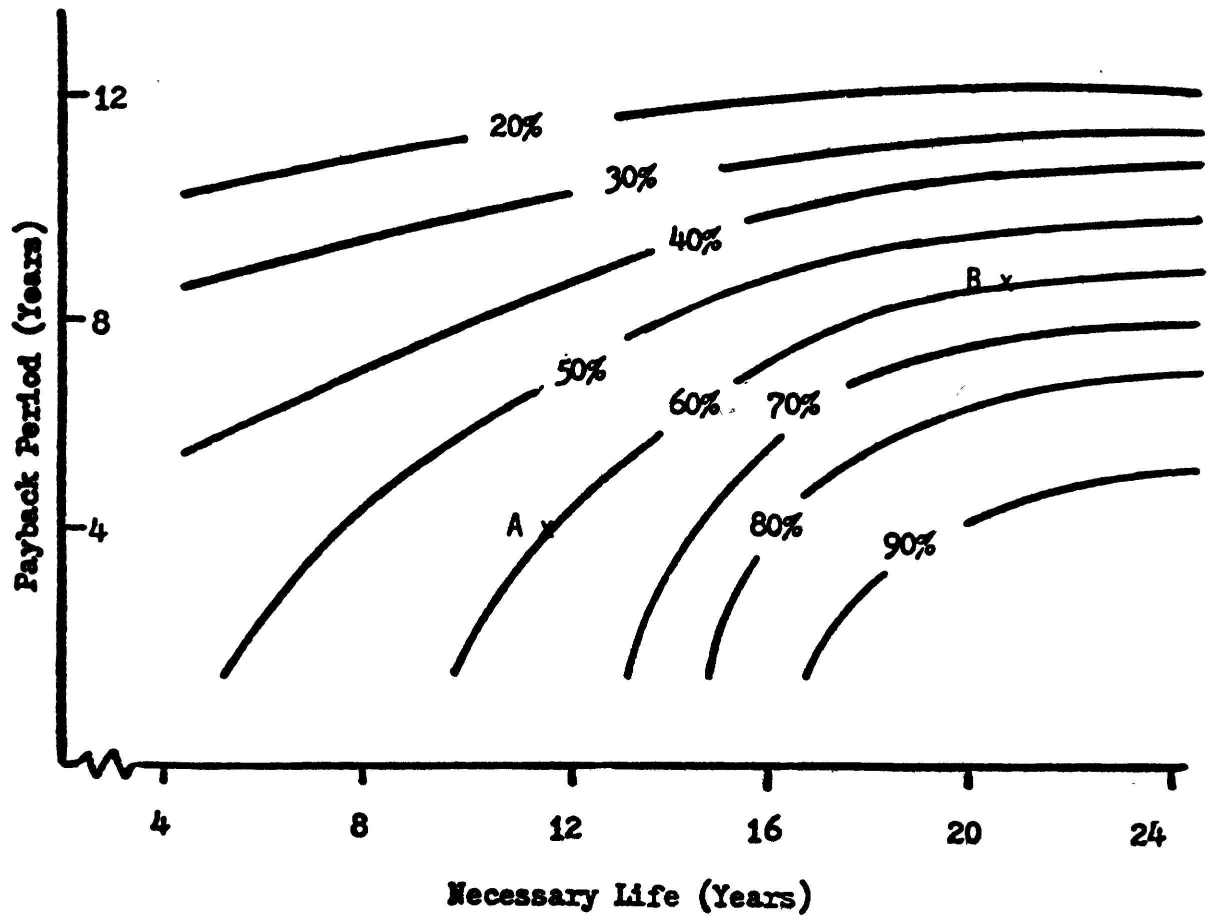
5.4 Product Development Guidance

The acceptability distributions can also be used to provide PV-product development guidance. The system designer, in developing the PV product, would like to know how much total acceptance will increase with an incremental change in say the payback period or the lifetime of the system. He can compare this information with incremental cost and thereby make a rational decision on system design trade-offs. This situation is analogous to government's problem in allocating funds between the different policy options.

A useful means for exploring system design trade-offs is the iso-acceptance curve, conceptually the same as the indifference curve used in economics. Figure 5.1 presents iso-acceptance curves for payback period versus system lifetime in the agricultural sector. Each curve is sketched through the locus of points with the same overall probability of acceptance on the two system characteristics. These curves represent the trade-offs between system characteristics. Thus, the same percentage of farmers are satisfied with each pair of values along a given iso-acceptance curve. Referring to cost estimates, the system designer can determine target values for payback and system lifetime for a given level of acceptance.

Figure 6.1

Payback Period vs. Necessary Life Acceptability Curves



Source: [16, pg. 67]

Consider Figure 5.1. Two points, A and B, are marked. A represents a 4-year payback and a 12-year lifetime. B represents an 8-year payback and a 20-year lifetime. Were either of these conditions to occur, 60 percent of farmers would find PV acceptable on these two dimensions. Thus, farmers on average are willing to pay a 4-year payback "premium" (8-4) to obtain an extra 8 years (20-12) in system life (assuming current system design is at point A). Figure 5.1 also indicates that although low values of payback and high values of system life are needed to get high acceptance (5 and 17 years respectively for 80 percent), less stringent values will still capture some market (e.g., 11 and 11 is acceptable for 25 percent). This information would be important to a marketer or a design engineer.

6. Insight into PV Policy Development

PV1 is an expensive simulation model to use, both in terms of computation costs and time used waiting for output. It is impossible to simulate all possible government policy strategies to find the best one. The size of the PV model (containing over 100,000 decision variables for a 20-year model, related to one another in a highly non-linear way) precludes analytical or numerical optimization. It is therefore useful to develop insight into the structure of optimal government spending policies to guide the search for superior policies. This section presents some theoretical results that shed light on:

1) The structure of optimal deployment of market development (MD) spending on PV demonstration installations.
2) Optimal subsidy strategies for new technologies which are governed by diffusion processes and experience cost declines.

These results will suggest a subset of policy options that should lead to the most effective government strategies. Section 7 compares these theoretical results with sample PV1 simulation results under 15 different government policy strategies.

6.1 Optimal Market Development Deployment

Lilien [1979] modifies a diffusion model introduced by Bass [1969] to study the theoretical implications of market development spending on market penetration over time. The Bass model was selected for analysis because it is simple, flexible, and has been applied to a number of different product applications. The analysis of the modified model suggests optimal strategies in terms of:

1) The timing of demonstration programs, and

2) The allocation of demonstration programs over sectors.

Assumptions necessary to the analysis of the model somewhat limit the applicability of the results. Nevertheless, there are several general implications which give insight into how and when government funds should be deployed.

Bass's model of diffusion takes the following simple form:

$$\frac{ds(t)}{dt} = \left(p + q\,\frac{s(t)}{s^*}\right)(s^* - s(t)) \qquad (6.1)$$

where:

$s(t)$ = number of firms having adopted an innovation by time t ($s(0) = 0$)

s^* = total number of firms considered eligible to adopt the innovation

p = coefficient of innovation; this equals the rate of product adoption when there have been no previous purchases

q = coefficient of imitation; the effect of previous purchases on the rate of adoption.

Lilien modifies this model to study first the effect that the timing of demonstration programs has on market penetration.

6.1a <u>The Timing of Demonstration Programs</u>

Under Lilien's modification, the Bass model takes the form:

$$\frac{ds(t)}{dt} = (p + q\,\frac{T(t)}{s^*})(s^* - s(t)) \tag{6.2}$$

where:

$T(t) = s(t) + A(t)$, where $A(t)$ is the number of government-sponsored demonstration programs installed by time t.

Analysis of this modified model proceeds under two important but reasonable assumptions: the first assumption is that government demonstration installations are indistinguishable from privately owned installations, implying that imitators are equally influenced by any successful product. The second assumption is that neither the coefficient of innovation, p, nor the coefficient of imitation, q, depends on demonstration programs (p and q are not functions of A(t)).

Since A(t) is a cumulative total of government-sponsored installations, it can be shown by separation of ds(t)/dt into two components that ds(t)/dt will be maximal when all demonstration program resources are used as early as possible. Intuitively, this follows since one would expect that early deployment of the maximum number of installations would lead to high early acceptability on the technical screen described in Section 2, thereby accelerating market penetration. Clearly, this early deployment forces acceptability on the technical screen to be always equal to or greater than the acceptability generated by any other deployment over all time. This result is general and should apply to innovations that are <u>technically sound</u> where government development programs are applicable. Kalish and Lilien [1980b] have investigated the timing of a PV demonstration program when negative feedback from various types of system failures is possible and show that, currently, a demonstration program should not yet begin.

The usefulness of this analysis is limited by the assumption that government has an allocation of installations to build, instead of the more realistic assumption of a fixed monetary budget, since it does not consider experience curve cost declines. To illustrate, if stated government policy is to build 100 installations independent of cost, then it makes sense to put them up as early as possible. If, on the other hand, a budget of $10 million is allocated to demonstration programs, then a greater number of cumulative installations can be built if the funds are deployed over time instead of early and all at once, assuming the innovation sees cost declines over time. Thus, if the cost of the innovation is expected to decline, and the government is limited by a fixed monetary budget, then the solution to temporal deployment becomes more complex. Nevertheless, if cost reductions are caused by increases in cumulative sales (learning curve effects), then a sufficient number of government installations must be deployed early to cause the future cost reductions.

6.1b Allocation over Sectors

Optimal allocation of government demonstration programs over sectors is studied by modifying the Bass model under the assumption that diffusion rates vary by sector. It is assumed that q, the coefficient of imitation, is a function of the cumulative level of demonstration program support, A, so that

$$q = f(A)$$

Bass's equation now becomes:

$$\frac{ds_i(t)}{dt} = (p_i + f_i(A_i(t)) \,.\, T(t))(s_i^* - s_i(t)) \tag{6.3}$$

$i = 1$ to the number of sectors.

If $T(t)$ is replaced by $A(t) + s(t)$ then a sectoral imitation parameter appears in the equation, namely, d, where

$$d_i = A_i \,.\, f(A_i)$$

Lilien concludes that if each sectoral imitation parameter, d_i, is a concave function of the number of demonstation installations, then optimal allocation occurs when installations are spread out over sectors. A concave function implies that each additional demonstration project yields a positive but diminishing marginal return for diffusion over the previous installation.

If each sectoral imitation parameter is a convex function then all demonstration installations should be allocated to one sector. A convex function implies that each succeeding installation generates an increasing marginal diffusion rate. Note, however, that in a finite market it is impossible to have always increasing marginal returns. Thus, all imitation parameter functions must ultimately become concave.

A likely functional form for the imitation parameter then is one that is at first convex and then turns concave. This implies that the first few demonstrations will show increasing marginal returns but eventually additional demonstrations will muster only diminishing marginal returns. This functional form assumes an S-curve shape. An optimal strategy for an S-shaped response is to concentrate installations in one area at a time until marginal private sales begin to slack off and then to spread out.

6.2 Optimal Subsidy Strategies

As with the timing of demonstration programs analysis, insight can also be gained into optimal subsidy strategies through analysis of a theoretical, mathematical model. Kalish and Lilien [1980a] study a simple formulation of a supply-demand model for a new innovation under the assumption that the subsidy a consumer receives is some constant percentage of the purchase price paid. To make theoretical analysis tractable, the authors impose several simplifying assumptions:

1) There are no subsidy ceilings (limits) in effect
2) Tax considerations are ignored
3) Firm pricing behavior is analyzed only as a cost-plus or short-term profit maximization problem - net present value profit maximization is ignored.
4) The cost per unit of production is a decreasing function of cumulative production
5) Demand for the innovation is a function of price to the consumer and of word-of-mouth effects. Exogenous variables, such as the state of the economy, which might affect demand, are considered static.
6) Consumers do not try to anticipate government subsidy. (It is plausible, for instance, that a consumer may delay action in anticipation of future government policy.)

In contrast to assumptions (1) and (2), the federal and state governments offer a variety of subsidy programs, many with subsidy ceilings and many in the form of a tax credit instead of a flat rate percentage decrease in price. Although the Kalish-Lilien model ignores these differences, the analysis is likely to hold suggestions about the effect a price subsidy strategy is likely to have on new product diffusion.

Kalish and Lilien analyze their supply-demand model under different scenarios of varying demand elasticities and changing firm revenues. An understanding of their main results requires the following definitions:

$p(t)$ = price charged by firm at time t

$x(t)$ = cumulative sales (same as number of adopters)

$r(t)$ = the portion of the price, $p(t)$ actually paid by the customer. ($1-r(t)$ = subsidy rate)

$x(t)$ = $f(x(t), p(t),\ldots)$ demand equation

$\eta(t)$ = price elasticity of demand

Their analyses also assume a single producer industry. From their assumptions they develop three fundamental results.

Result 1: If demand for the innovation is constant over time and elastic ($\frac{d\eta}{dt} = 0$, $\eta > 1$) then the optimal subsidy strategy is to spend in a continuous and monotonically non-increasing fashion if firm revenues are non-decreasing over time. Non-decreasing firm revenues are assured when word-of-mouth effects are positive ($\frac{df}{dx} \geq 0$) and prices decline with experience ($\frac{dp}{dx} \leq 0$).

Price will decline with experience under the assumptions of 1) experience curve cost declines and 2) price set on a cost plus or short-term profit maximization basis. It is unlikely that the government would consider subsidizing an innovation unless the innovation exhibits such price decline and positive word-of-mouth effects. In general, however, the assumed condition of constant price elasticity of demand is unrealistic. The next result relaxes this condition.

Result 2: The conclusion of Result 1 still holds under the relaxed assumption of an elastic but now varying elasticity, as long as the price elasticity of demand decreases with price declines as well as with time ($\frac{d\eta}{dr} \geq 0$, $\frac{d\eta}{dt} \leq 0$).

The new condition that elasticity decrease with declines in price is reasonable to expect for products early in their life cycles, where, if risk of purchase is extremely high, it is doubtful that drops in price will stimulate increasing percentages of quantity demanded. Such a scenario is especially true of unusual and high priced innovations because of their inherent riskiness. Yet, in many instances, innovations of this kind are initially priced at levels in the inelastic region of the demand curve because cost declines have not been marked enough to allow competitive pricing. For these innovations, the subsidy strategy of Results 1 and 2 is an inappropriate one with which to start. Whereas this strategy may be correct to implement early in the life cycle, clearly some other strategy must be determined for innovations just entering the marketplace in a region of price inelasticity.

Result 3: If demand for the innovation is inelastic and constant over time ($\eta < 1$, $\frac{d\eta}{dt} = 0$) and if revenues are non-decreasing, then the optimal subsidy strategy is to fully subsidize installation costs at the beginning until the subsidy budget is exhausted. Of course, if firm revenues are non-increasing, then the subsidy should be withheld as long as possible in the hope that revenues will become non-decreasing in the near future.

Explicit conditions for non-decreasing revenues could not be developed. Nevertheless, as with Result 1, the condition that elasticity must remain constant is unrealistic. As cumulative production increases and costs consequently fall, the price of the innovation will approach and finally enter the elastic region of the demand curve. Alternatively, word-of-mouth effects may shift the demand curve such that demand becomes elastic with no significant change in price.

Kalish and Lilien conclude that an optimal subsidy policy is to subsidize fully when the innovation first comes on the market, as long as the product "works" and its price is low enough so that subsidized price brings it into a price-elastic region. The subsidy should be decreased over time once demand becomes elastic and non-increasing. This two-part strategy will be effective for the "good" product, one that generates positive word-of-mouth effects thereby sustaining itself on the marketplace. Government subsidy spending for the "good" product grows proportionally to firm revenues when installations are fully subsidized, but then peaks and declines with the lessening of the subsidy rate. If firm revenues do not initially grow because of high product price, the subsidy should be delayed until costs decline sufficiently for sales to increase. At that point the strategy outlined at the beginning of the paragraph should be implemented.

One obvious omission of the Kalish and Lilien analyses is the case where demand is elastic at the unsubsidized price, but the elasticity is increasing. The situation will generally occur when demand moves from the inelastic to the elastic region of the demand curve since elasticity is likely to continue to increase. In this region of the demand curve, government can stimulate increasing marginal sales in the private sector for each incremental percentage increase in the subsidy rate. A policy of full subsidization would seem to be recommended in this instance.

6.3 Consequences for Photovoltaics

Recall that government subsidy spending for PV is independent of the

$1.5 billion allocated to the other government policy options. Thus, the DOE-PV program need make no trade-offs between spending money on subsidies versus other programs as is the situation with market development spending. In this sense, the theoretical analysis of optimal subsidy strategies is a self-contained problem for photovoltaics. Realistically, however, spending in the other policy options must be coordinated with the subsidy strategy if maximum PV diffusion is to be achieved. Clearly, if at times these other options are more cost-effective in bringing down the cost of a PV installation, then some subsidy spending should be delayed until more opportune moments arise. For instance, the discrete decreases in PV costs expected from changes in stage of technology might be reason enough to withhold subsidy funds until they can be used more effectively in conjunction with TD and AR&D spending.

Finally, government's allocation of funds to the PV demonstration program (MD) depends on its allocation to technology development (TD) and advanced research and development (AR&D). The $1.5 billion allocated to the National Photovoltaic Program must be split between MD, TD and AR&D. Both TD and AR&D spending work to lower PV costs, and in so doing increase the fraction of the market who find PV acceptable by raising the acceptability level on the payback screen. There is a trade-off between raising the technical acceptability through MD spending and raising the payback acceptability through TD and AR&D spending. PV1 will be a useful tool in the determination of a reasonable division of funds between the three policy options.

7.0 Some Sample PV1 Analyses

The results of the last section gave insight into optimal allocation strategies for market development and subsidy expenditures. Although the implications of these results are somewhat confined by the assumptions on which they are based, they simplify the search for superior allocation strategies. In this section, market penetration and cost forecasts from the PV1 model are analyzed for 15 different government policy strategies. These strategies were selected to compare with the results outlined in Section 7. They provide the basis for an initial sensitivity analysis of the theoretically optimal strategies.

Here we use the words "model" and "strategy" interchangeably. Note that the way we use the word "model" should not be confused with the PV1 model. Instead a model is the set of user-defined inputs that specify government policy actions, stages of the PV technology, the duration of the forecast period, the number of sectors in the forecast and many other control variables of lesser importance. To make comparisons of the 15 strategies meaningful, all variables unrelated to government policy were fixed with the exception of the annual real rise in electricity rates, which is 3 percent for the first eight strategies and 10 percent for the last seven. The decision to use two electricity rate rises was made in consideration of the instability of oil prices. Clearly as the cost of utility generated electricity increases, the PV product will look better and better in the eyes of potential adopters. The model results demonstrate this relationship dramatically. It is recognized that many utilities use fuels other than oil in their electricity generation and that the use of one overall electricity rate rise for all fuels is probably inadequate. To remedy this oversimplification, a database of utility fuel mixes is currently being assembled to allow the PV1 user to input fuel-specific rate rises. In using these rate rises PV1 will assume that utilities annually increase electricity costs commensurate wth the rise in their fuel costs.

Descriptions of the 15 government allocation strategies appear in Tables A-1 to A-15 of Appendix 1. These tables present summary cost and penetration results. Table A-1 serves as an overall reference, presenting results for the baseline strategy in which total government spending was set to a minimal level of $75 million in market development. All other spending was set to zero.

All strategies were specified as 6-sector, 15-year models. Except for the baseline strategy, all strategies were allocated approximately $1.5 billion over the first ten years of the forecast period, consistent with the funding available to the National Photovoltaic Program. This money was specifically allocated to the market development (MD), technology development (TD) and advanced research and development (ARND) policy options. Since the number of model runs was limited, TD and ARND spending allocations were made identical in all strategies to allow for a controlled analysis of the effects of MD spending on PV diffusion. TD spending was held invariant at $100 million for the first four forecast years and ARND spending was held constant at $100 million for the first seven. (In all models, TD spending causes Stage 2 technology to arrive in year 5 and ARND spending causes Stage 3 to arrive in year 8. An explanation of the specifications of Stage 2 and Stage 3 arrival dates is given in the appendix to this chapter). MD spending was set at $75 million in strategies 2, 3, 4, and 5 and then upped to $500 million in strategies 6-15. Strategies 2, 3, 4, and 5 consumed less than $1.5

billion because MD funding was set to a minimal level. For each strategy, advertising costs come to 20 percent of MD spending.

Subsidy policy for the 15 strategies was specified independent of the other policy options because subsidy funding is not provided by the National Photovoltaic Program. Unlike MD, TD, and ARMD, which are constrained by a total $1.5 billion budget, subsidy funds are assumed to be unlimited. Nevertheless, PV1 can simulate a constrained subsidy budget by setting annual subsidy rates to zero after the budget ceiling has been reached. As will be seen in Table 8.1 later, cumulative subsidy spending varies dramatically. This is because cumulative subsidy spending is calculated as a fraction of the dollar volume of private PV sales, and dollar volume varies considerably across strategies. Some of the variance in dollar volume is caused by the effects that different strategic allocations of MD, TD, and ARMD have on PV costs and acceptabilities. Much of the difference in subsidy spending, however, can be attributed to the application of different subsidy rates. For instance, strategies 6 and 7 are identical except for the sizes of the subsidy rates, yet cumulative subsidy spending differs by $2.23 billion.

Although the spending variances make comparisons of market penetration forecasts difficult between some pairs of strategies, there are many important, and to some degree generalizable, results which proceed from the analyses of this section.

For analysis purposes, the warranty of a PV system was set to 30 months and the lifetime to 20 years and both were left unchanged for all strategy runs. Thus, acceptabilities on the warranty and lifetime screens also remained constant, and can be considered as having negligible responsibility for differences in market penetrations between strategies.

7.1 General Results

Government spending can accelerate diffusion by increasing the awareness and the acceptability of PV. In the 15 model runs, government spending influences market penetration in three ways:

1) MD spending increases awareness

2) MD installations increase technical screen acceptability

3) MD, TD, AR&D and subsidies all work to lower PV costs, and thus increase the payback acceptability.

From analysis of the 15 model runs, the following general conclusions follow concerning the relationship between government spending and market penetration of PV. Detailed comparison analyses of the strategies are included in the next subsection.

1. Market Development Spending: Without MD spending PV technology does not diffuse. This seems to be true regardless of how much government spends on TD and AR&D. Further, the availability of as much as a 40 percent subsidy is not enough to stimulate much additional adoption when MD spending is low. Even full subsidization is relatively ineffective in early forecast years. There are two major reasons for the delay: first, awareness of PV remains low throughout the forecast period because advertising expenditures, which in PV1 are a fraction of MD spending, are negligible; second, diffusion is delayed because potential private adopters are unwilling to risk a product that has little demonstrated reliability. The lack of government purchased installations therefore causes the technical screen acceptability to be near zero.

If all other government policy variables remain the same, MD spending has the greatest positive effect on market penetration when it is spent in the early years. By deploying MD funds rapidly, government creates immediate widespread awareness of PV and also accelerates technical screen acceptability, and because both awareness and technical acceptability are functions of cumulative installations, they maintain high values after MD funds dry up. These preliminary findings corroborate the theoretical results of Section 5.

Concentration of MD funds in certain sectors dramatically accelerates overall PV penetration into the private sector. It was found that the agricultural sector is particularly receptive to early MD expenditures, but that annual sales peak quickly, after which time MD spending has no further significant effect. Concentrated allocations of MD spending have the greatest impact on diffusion acceleration in the residential and commercial sectors. This occurs primarily because the residential and commercial sectors are the two largest in terms of total market potential and number of potential adopters. In principle, diffusion is accelerated fastest in sectors where contact between intra-sector members is greatest--therefore the largest ones.

To illustrate, assume that the technical acceptability screen distributions are identical for all sectors. As government market development sponsored installations are built, and greater percentages of potential adopters pass through the technical screen, ceteris paribus, proportionately more sales result in large sectors than in small sectors. This means that, in absolute terms, greater numbers of potential adopters will actually adopt in the larger sectors. Since technical acceptability is calculated based on an absolute number of prior successful installations, the diffusion of photovoltaics will be accelerated fastest, for a given MD expenditure, in the largest sectors.

This result holds as long as inter-sectoral interactions are less than unity; if all interactions are unity, then MD funds should be spent in sectors where installations can be bought at greatest value per peak watt. Furthermore, since all installations would cause identical perceptual effects, regardless of PV array size, government could derive the most benefit from an installation in the sector using the smallest average PV installation size, i.e., the residential sector.

2. Subsidy Spending: Whereas MD spending is crucial in the early years of PV diffusion, subsidy spending assumes a vital role in later years. The size of the subsidy necessary to drive diffusion depends totally on the relative cost of PV electricity to utility-generated electricity. In early years, when the cost of PV is highest and marginal electricity rates are lowest, private adoption of PV can only be stimulated by complete or near-complete subsidization. The average subsidy cost to government per peak watt is extremely high, and though much is spent, little is purchased. It is a tricky business, however, to try to locate a subsidy level that is not too costly to government but that is still able to attain a reasonable stimulation of the market.

An unfortunate fact about photovoltaic subsidies is that they seem to have no permanent stimulating effect on PV sales: when subsidies expire, annual sales fall back to levels little different than pre-subsidy sales. The cause of subsidy's inability to create permanent sales effects lies in the PV cost structure. The PV cost formulation does not incorporate learning curve effects: thus, subsidies induce greater cumulative sales, but the cost reductions which can accelerate adoption do not result. Instead, costs are partially determined using an economies of scale approach. While economies of scale certainly exist in the BOS cost structure, as well as in Stage 1 module technology, where plants are not at minimum efficient scale, the presence of a learning cost curve decline also seems justified. JPL's ommission of learning curve effects from the PV cost formulation was based on the belief that the PV technology changes so rapidly that such effects never develop; a future revision of PV1 is expected to incorporate a cumulative sales effect. Obviously subsidies will have more impact on the rate of diffusion when learning curve effects are modeled. It is not clear how important the learning curve effects are expected to be but the possibility exists that they will be overshadowed by cost declines associated with TD and ARND spending during the years of Stage 1 and Stage 2 technologies. After Stage 3 arrives, and a relatively stable technology is put in place, learning curve effects will probably assume importance.

The most salient benefit of government subsidization occurs when the price of PV hovers just above a threshold level where modest decreases in price can produce quantum increases in PV sales. An infusion of subsidy money in this situation can invigorate the market. The threshold price level is determined by the relative costs of PV and utility-generated electricity. The faster PV costs decrease and the higher the real annual electricity rate rise, the more rapidly the threshold price level is reached. The results of the 15 strategies indicate that the price of PV nears the threshold level only after Stage 3 technology comes on line, suggesting that subsidy spending be delayed until that time. The wisdom of this strategy is reinforced if the assumption is correct that learning curve effects only take on importance in third stage technology. The theoretical results of Section 6, which are derived for new technologies that experience learning curve cost declines, should then apply. This is partially borne out by comparison of some of the strategy results.

7.2 Detailed Analyses of Government Policy Actions

The analyses of this section use Tables A-1 to A-15; the reader should refer to these tables to see differences in the time path of diffusion as well as to obtain detailed strategy descriptions. Table 7.1 presents projections of cumulative megawatts installed and W_p/dollar of government investment for the 15 cases, providing a rough summary comparison.

1. The Base Case-Minimal Government Support: Table A-1 presents the baseline results. A minimal $75 million in MD was allocated in Strategy 1 to develop as threshold-model for comparison. Here over 90 percent of final cumulative sales are private. Approximately 75 percent of cumulative installed peak kilowatts are in the agriculture sector. Although agriculture seems to be a prime target for diffusion acceleration, it becomes clear in other strategies that this sector is generally unresponsive to later government spending.

2. Comparison of Strategies 1, 2, and 3: All three strategies have minimal MD spending. Strategies 2 and 3 have large allocations of TD and ARMD funds. Strategy 3 has a 40 percent subsidy for all 15 forecast years. There is virtually no difference in cumulative sales for these strategies. PV costs in strategies 2 and 3 reach low levels much faster than in Strategy 1, yet prices are not low enough to stimulate sales. Even the 40 percent subsidy, which costs the government an additional $142 million over the baseline, cannot initiate more than a few hundred extra peak kilowatts in sales.

3. Comparison of Strategies 3 and 4: Both strategies are identical

except for the subsidy rate which is raised to 80 percent in Strategy 4. Through the first seven years, differences in sales are not remarkable. Yet when the price of PV drops to about 45 cents per peak watt in year 8, sales take off in Strategy 4. It is clear that the cost of PV must be reduced substantially if the sales rate is to accelerate. In achieving this reduction in cost and increase in sales an enormous subsidy cost is incurred: $3.59 billion. All but $60 million of this figure is spent in the last 8 years; however, this is a relatively cost effective strategy, yielding .88 I_p/$ of investment.

4. Comparison of Strategies 4 and 5: Strategy 5 has full subsidization through the first 10 years, and 40 percent thereafter. Sales in Strategy 5 approximately double each year from year 5 to year 10. Undoubtedly, the market expansion factor is limiting sales during this period. By year 10 cumulative sales in Strategy 5 are triple those in the same year of Strategy 4. The reduction in the subsidy rate in year 11 to 40 percent, however, stops sales. In fact, sales in year 14 of Strategy 5 are little different from those of the baseline strategy, about 20,000 peak kilowatts.

5. Comparison of Strategies 6 and 2: Strategy 6 is identical to Strategy 2 except that MD spending is increased to $50 million annually for years 1 through 10, and is then eliminated in years 11 through 15. Total cumulative sales in Strategy 6 are double Strategy 2's, but private sales are only about 50 percent more. Table 7.1 presents cumulative private market penetration in relation to subsidy spending. Since only MD spending varies between these two strategies, all sales differences must be MD-induced. Noting that total cumulative sales between them in years 10 through 15 differ by less than 3000 peak kilowatts, it is

Table 7.1

Cumulative Subsidy Spending Versus Market Penetration

Strategy		Cumulative Subsidy Spending ($000,000)	Cumulative Private Market Penetration (000 KW_p)	Average Subsidy Cost Per Peak Watt ($)	Peak Watts Installed Per Dollar of Gov't Spending
	1	0	147	0	1.[illegible]
	2	0	147	0	.12
Elect.	3	141	147	.96	.11
Rate	4	3,587	4,203	.85	.83
Rise=	5	1,130	726	1.56	.32
3	6	0	209	0	.13
percent	7	2,225	1,335	1.67	.35
	8	3,989	1,792	2.23	.32
	9	8,632	13,561	.64	1.33
	10	9,341	15,598	.60	1.42
Elect	11	1,409	1,052	1.34	.35
Rate	12	2,336	2,866	.82	.73
Rise=	13	3,025	4,394	.69	.95
10	14	1,936	4,299	.45	1.21
percent	15	3,903	7,244	.54	1.32

evident that MD spending promoted about 60,000 peak KW in additional private sales during the years it was being spent. This sales increase is hardly exceptional, but it can be attributed to heightened awareness and greater technical screen acceptability, both the result of large amounts of MD spending. The fact that sales are so similar in later years is somewhat puzzling; the explanation is that heightened awareness caused most of the extra private sales. When MD spending ran out, awareness fell back to a low level, the additional sales not enough to sustain a level of awareness much higher than in Strategy 2.

6. Comparison of Strategies 6 and 7: Strategy 7 is Strategy 6 with subsidy. The full subsidy allocated in the first two years of the Strategy 7 forecast stimulates few sales, undoubtedly because technical acceptability, awareness, and even payback acceptability are low. (Note that in spite of full subsidization the subsidized cost per peak watt is still high, a situation caused by the federal subsidy dollar ceiling limit.) Market penetration and subsidy spending grow dramatically thereafter until year 11, when the reduced 40 percent subsidy takes effect. Afterwards, private annual sales are little different than in the baseline case. Demand is in such an inelastic region that a drop in price from $2.03 to $1.22 per peak watt induces only about 2500 additional peak KW in sales. (MD spending accounts for about 2500 KW in year 15 of the baseline strategy.)

7. Comparison of Strategies 7 and 8: In Strategy 8, $500 million in MD funds are deployed over a 5-year period instead of a 10-year period as in Strategy 7. Total penetration is increased by 26 percent but subsidy spending increases by 79 percent from $2.23 billion to $3.99 billion. The average subsidy cost per peak watt jumps from $1.67 to $2.23 (see

Table 7.1). Nevertheless, once again, annual sales drop precipitously when the subsidy rate is lowered in year 11.

Much of the additional subsidy spending in Strategy 8 occurs in early years when total subsidization costs per installation are high. In those years higher awareness and higher technical and payback acceptabilities, caused by concentrated RD spending, result in higher sales and therefore additional subsidy costs. It seems that, in spite of increased penetration, the strategy of accelerating RD expenditures fails because it is unable to generate more than mediocre, non-increasing sales in later years. In the same sense, the extra subsidy money spent is also ineffective. Perhaps a not unreasonable criterion for government to adopt in its decision to intensify subsidy expenditures is that the average subsidy cost per peak watt must diminish with extra subsidy spending.

8. Comparison of Strategies 9 and 7: These strategies are identical, but in Strategy 9 the real annual rise in the price of electricity is increased from 3 percent to 10 percent. Divergences in market penetration between the two strategies begin in year 6 and by year 15 total penetration differs by 12 million peak Kw. Although subsidy increases to a cumulative $8.6 billion in Strategy 9, the average subsidy cost per peak watt falls to $.64. This compares quite favorably to $1.67 in Strategy 7. Comparisons of PV costs in Tables A-7 and A-9 plainly reveal that the reduction in gross cost per peak watt is involved in the stimulation of diffusion. The reduction in cost is caused by increased economies of scale in balance of systems costs resulting from higher annual sales. The increase in sales occurs because payback acceptability mushrooms, the outcome of the rise in price of utility-generated

electricity relative to that of PV electricity. Most important of all is that sales in years 11-15 of strategy 9 are large and annually increasing. Apparently, annual sales can sustain lower gross PV costs which in turn sustain annual sales.

The results of strategies 9 and 7 imply that the relative costs of PV and utility electricity will ultimately determine PV's place in the market. The analysis is not suggesting that a 3 percent real annual rise in the price of utility electricity will effectively block PV penetration, or that a 10 percent rise will guarantee market success; only that the electricity rate rise will play the key role in determining how greatly and how quickly PV diffuses.

9. Comparison of Strategies 10, 11, and 12: Comparisons of these strategies show how different subsidy strategies affect diffusion. Only subsidy rates are varied between strategies. Since the application of subsidy rates is the same in years 1-10 of strategies 11 and 12, subsidy spending and market penetration are also identical. The termination of subsidy funds in Strategy 11 kills off sales in years 11-15. In maintaining a 40 percent subsidy these last five years, however, PV sales in Strategy 12 are boosted 1.8 million peak Kw over sales in the same period in Strategy 11. The additional subsidy cost of these sales is $973 million. Yet, as a result, average subsidy cost per peak watt drops to $.92 from $1.34. The effectiveness of subsidy spending is thus substantial when gross PV costs approach the threshold level where demand becomes elastic.

Strategy 10 has generally higher subsidy rates than Strategies 11 and 12 and sales are consequently much stronger. Even though PV sales in years 11-15 of Strategy 10 dwarf sales in Strategy 12, it is clear that diffusion is being successfully accelerated with a lower subsidy rate (40 percent compared to 60 percent) in Strategy 12, and at a much lower cost. (Subsidy costs in year 15 of Strategy 12 are 28 percent of costs in Strategy 10.) Still, the average subsidy cost per peak watt drops significantly from \$.82 to \$.60 when the subsidy rate is increased to 60 percent from 40 percent.

It is unlikely that government will allocate \$9.34 billion in funding to photovoltaic subsidy policy, so Strategy 10 in itself is probably not realistic. Nevertheless, an important issue arises in discussing Strategy 10 in relation to Strategy 12: how should government decide what the time path of subsidy rates should look like once demand becomes elastic. The use of high subsidy rates will create large immediate increases in PV sales, but the subsidy spending budget will empty quickly. And as other strategies have demonstrated, once subsidy inoculations cease, PV costs rise and sales fall. It is not clear, however, whether the same subsidy budget, spent more moderately over a longer period of time because of lower subsidy rates, would achieve less or more diffusion. Future analyses of other strategies may help to decide this issue.

The necessity of maintaining a constant or increasing demand for PV, so that PV manufacturers are not periodically driven from the industry when subsidy rates are suddenly dropped, argues for the use of subsidy rates which can be gradually reduced over time to maintain a stable time path of demand. When the subsidy budget runs out the rate should be low enough that a smooth transition in demand can occur. By such time the cost of electricity from utilities will hopefully have increased to a point where a non-subsidized PV price will generate sales on its own.

10. Comparison of Strategies 12 and 13: MD spending in Strategy 13 is expended in the first year. Subsidy rates and TD and ARND spending are the same. Thus, only the time allocation of MD funds varies between strategies 12 and 13. By accelerating MD expenditures, both subsidy costs and PV sales were increased, while the average subsidy cost per peak watt decreased from $.82 to $.69. The increase in market penetration is due to the immediate elevation of awareness and technical acceptability supplied by an overdose of MD spending. It appears that $500 million in year 1 is sufficient to create maintainable awareness and technical acceptability levels since annual PV sales are sustained at high levels for all 15 years of the model. Because costs and penetrations are different, it cannot be concluded that one strategy is superior to the other.

11. Comparison of Strategies 13 and 14: Comparison of market penetration for these strategies illustrates that early subsidization costs money but has little bearing on total diffusion in later years. Referring again to Table 7.1, observe that while cumulative PV sales in Strategies 13 and 14 differ by just 2 percent, Strategy 13 costs 50 percent more ($1 billion) than Strategy 14 in terms of subsidy expenditures. It is clear that the large early subsidy rates of Strategy 13 cost the government money that could have been saved had the subsidy been delayed.

12. Comparison of Strategies 15 and 12: Aside from all MD funds being allocated to the residential and commercial sectors in Strategy 15, these strategies are identical. The concentration of MD funds in these sectors caused a 67 percent increase in subsidy expenditures in comparison to Strategy 13. Penetration, meanwhile, increased 253 percent. The data

strongly suggest that, had subsidy spending been limited in Strategy 15 to that of Strategy 13, the cumulative sales in Strategy 15 would still have been slightly higher. The more important result, however, is that diffusion occurs fastest in the residential and commercial sectors. A year-by-year comparison of cumulative installed peak kilowatts makes this result apparent.

8.0 Conclusions, Assessment and Extensions

8.1 Conclusions and Extensions Needed for PV1

The diffusion of the photovoltaic technology will not occur immediately. Yet, government money, spent wisely, can accelerate private sector adoption and shorten the time until the technology becomes viable. Not surprisingly, the analyses of government strategies showed that the cost of PV is the major barrier to PV's successful diffusion: little adoption will occur while PV is a non-competitive energy source. How long it takes for PV to become competitive will in large part be determined by the arrival dates of the second and third stage technologies. Reasonable assumptions were made in the model about the arrival dates of these technologies, but there is certainly no guarantee that they will arrive "on time."

Since the dates of future technology changes are unknown, the PV1 model cannot forecast the time path of diffusion with much certainty. In addition, PV1 penetration forecasts have limited validity, in an absolute sense, because PV1 uses a time-invariant probability-of-purchase as well as a time-invariant aggregate distribution fraction. While the absolute forecast numbers may be off, they are useful because they can be compared relatively between strategies to determine superior allocation policies.

Several results with broad implications surfaced in the strategy analyses of Section 8. They are summarized as follows:

1) When PV costs are high and far from competitive, subsidy spending is unlikely to help speed diffusion. Instead, subsidy spending is, in such circumstances, essentially wasted money.

2) Subsidy spending is very effective once PV costs approach competitive levels.

3) MD spending is essential to diffusion. Without it, the public remains unaware and PV is perceived as too risky to chance purchase.

4) MD spending is most effective when spent early. Diffusion can be accelerated particularly well in the residential and commercial sectors.

It must be stressed that government spending programs have to be coordinated to achieve maximum impact. The results indicate that, ultimately, a good MD policy coupled with a bad subsidy policy is not much better than no policy at all. The reverse also seems to be true.

Theoretical results on optimal MD spending patterns show that demonstration projects should be concentrated in sectors that show increasing marginal private sales for each additional government installation, but that funds should be spread out once a decline in private marginal PV sales is perceived. The analysis results, however, seemed to suggest that because of low intra-sectoral contact in the smaller-sized sectors, more MD funds should be allocated to the larger sectors.

The theoretical results on subsidy spending advocate a wait period until firm revenues begin to rise (i.e., annual sales begin to increase) before deploying subsidy funds. The position is taken that private purchases should be heavily subsidized initially, followed by a period of gradual reduction in the subsidy rate as the price elasticity of demand begins to decrease. Yet, in the strategy simulations on PV1, subsidy money was expended very rapidly under such a subsidy policy, because as penetration began to catch, price elasticity seemed to increase. A policy of near complete subsidization in such a situation quickly depletes a fixed budget; a reasonable budget might have been expended before subsidy dollars could make a permanent positive impact on the diffusion rate. The strategy analyses imply that the subsidy rate should be decreased as sales and elasticity increase: this saves subsidy funds for later years when modest spending can promote large sales increases which, because of economies of scale, begin to support a lower PV price level themselves.

The government strategies analyzed here were limited in number: no attempt was made to study the relation of the diffusion rate of PV to the allocation of funds to TD, ARND and advertising. It was also not possible to conclude much about the sensitivity of market penetration to the subsidy allocation strategy because the subsidy budget was not held fixed. The sensitivity of the diffusion rate to exogenous variables such as real annual electricity rate rise is certainly worth exploring through more model simulations.

An important assumption of the PV1 model is that all PV installations will work successfully. Under this assumption, technical screen acceptability will be a continuously increasing function of cumulative installations. The introduction of PV failures, however, could seriously set back the PV program. Work on modeling the failure possibility is currently under way. (See Lilien and Kalish [1980b] for some preliminary analyses.) How long PV diffusion would be delayed by installation failures will be a function of the number of failures, the seriousness of the failures, their visibility, the duration of time until all new installations are successful, and of course, the time it takes to change unfavorable perceptions into favorable ones.

Improvements that are needed to make the PV1 model more realistic include:

1) Estimation of region-specific distribution fractions which will increase over time;

2) Estimation of probability-of-purchase which may be sector-dependent and probably will change over time;

3) Use of a weighted average cost of electricity based on different real annual cost increases of the different fuels in a utility's fuel mix;

4) Incorporation of learning curve cost declines into the PV1 cost formulation;

5) Development of a distribution of average PV installation sizes for the commercial, industrial, agricultural and government/institutional sectors.

6) A breakdown of the residential sector into single family homes, duplexes, apartments, etc.

7) Compiling income distribution information so that PV tax credits can be modeled.

By making these changes and extensions to the model the forecast numbers of market penetration will assume increased validity. As the model stands currently, relative comparisons are safest.

8.2 Extensions to Other Technologies

The greatest asset of the PV1 model appears to be its incorporation of a believable model of consumer adoption. PV1 does not rely on an exogenously-defined functional form to derive market penetration forecasts, unlike other major solar penetration models. PV1 is more flexible than these other models because its basic diffusion-model structure leaves room for a wide range of diffusion phenomena to be added. Other solar diffusion models, which characterize diffusion phenomena with a handful of arbitrary parameters, cannot achieve the realism or the detail of the PV1 model approach.

In the same way, the model-structure and modeling approach appear applicable to other technologies. The PV1 model <u>is</u> PV specific, but the approach is general:

(1) Study and understand the likely adoption process for the technology under study.

(2) Build a behaviorally-based diffusion model, incorporating that understanding of adoption.

(3) Calibrate the model using as much objective data as possible.

(4) Study policy alternatives using a combination of quantitative model outputs and theoretical results.

The PV1 approach is adaptive, evolutionary and data based. Further use should demonstrate that it is self-correcting--when it is in error, the source of the error will become apparent and the model will be modified. This same set of model-based concepts should be applicable to a wide range of new technologies, especially in the energy field.

References

1. Arthur D. Little Inc., Solar Heating and Cooling of Buildings (SHACOB) Commercialization Report, Part B, Volume II, September 1977.

2. Bass, Frank M., "A New Product Growth Model for Consumer Durables," Management Science, January 1969.

3. Bernhardt, Irwin and Kenneth MacKenzie, "Some Problems in Using Diffusion Models for New Products," Management Science, October 1972, pp. 187-193.

4. Boring, E.G., "The Nature and History of Experimental Control," American Journal of Pscyhology, 67 (1954), 573-589.

5. Campbell, D.T. and J.C. Stanley, Experimental and Quasi-Experimental Designs for Research (Rand McNally, Chicago, 1963).

6. Choffray, J-M, and G.L. Lilien, Market Planning for New Industrial Products, New York: Wiley, 1980.

7. EEA, Inc., The Market Oriented Program Planning System--Industrial Sector Methods and Results, Draft Report, prepared for ERDA, 1977.

8. Energy Information Administration, Annual Report to Congress, 1978, Chapter 10.

9. Federal Energy Administration, National Energy Outlook 1980, U.S. Government Printing Office, Washington, D.C., February 1980.

10. Fliegel, Frederick C. and Joseph Kivlin, "Attributes of Innovations as Factors in Diffusion," The American Journal of Sociology, November 1966, pp. 235-248.

11. Gwynne, Peter, "Debate Continues on Photovoltaics," Industrial Research/Development, March 1979, pp. 40-44.

12. Jet Propulsion Laboratory, "Federal Policies to Promote the Widespread Utilization of Photovoltaic Systems" for DOE/CS-0014/2, Washington, D.C., March 1980.

13. Juster, F. Thomas, "Consumer Buying Intentions and Purchase Probability: An Experiment in Survey Design," American Statistical Association Journal, 61:658-96, September 1966.

14. Kalish, Shlomo and Gary L. Lilien, "Optimal Price Subsidy Policy for Accelerating the Diffusion of Innovation," Energy Laboratory Working Paper No. MIT-EL 80-004WP, October 1980.

15. Kalish, Shlomo and Gary L. Lilien, "Timing and the Role of Demonstrations in Photovoltaic Market Simulation," MIT Energy Laboratory Working Draft, November 1980.

16. Kalwani, Manohar U. and Alvin J. Silk, "On the Predictive Validity of Purchase Intention Measures: Some Applications of Morrison's Model," MIT Working Paper, January 1981.

17. Lilien, Gary L. and S. Thomas McCormick, "The Consumer Response to Photovoltaics: The MIT Sun Day Experience," MIT Energy Laboratory Report No. MIT-EL 79-005, February 1979.

18. Lilien, Gary L., "The Diffusion of Photovoltaics: Background, Modeling and Initial Reaction of the Agricultural-Irrigation Sector," MIT Energy Laboratory Report No. MIT-EL 78-004, March 1978.

19. Lilien, Gary L., "The Implications of Diffusion Models for Accelerating the Diffusion of Innovation," Technological Forecasting and Social Change, 17, 339-351 (1980).

20. Lilien, Gary L., "Model Relativism: A Situational Approach to Model Building," Interfaces, Vol. 5, No. 3, May 1975.

21. Lilien, Gary L. and Shlomo Kalish, "Models of New Product Diffusion: Current Status and Research Agenda," MIT Energy Lab Working Paper. 1979.

22. Lilien, Gary L. and Paul E. Johnston, A Market Assessment for Active Solar Heating and Cooling Products Category 2: A Survey of Decision-Makers in the HVAC Marketplace, Report to U.S. Department of Energy, September 1980.

23. Lilien, Gary L. and Martin Wulfe, "PV1: An Interactive Computer Model to Support Commercialization Policy Analysis for Photovoltaics," MIT Energy Laboratory Report No. MIT-EL 80-026.

24. Little, John D.C., "Models and Managers: The Concept of a Decision Calculus," Management Science, Vol. 16, No. 8, April 1970, pp. B466-B485.

25. Midgley, David F., Innovation and New Product Marketing, (New York: Halsted Press, 1977).

26. Morrison, Donald G., "Purchase Intentions and Purchasing Behavior," Journal of Marketing, Spring 1979, pp. 65-73.

27. Pruce, Leslie M., "Photovoltaics: The Sky's The Limit," Power, August 1979, pp. 84-86.

28. Rebibo, K., et al., "A System for Projecting the Utilization of Renewable Resources, SPURR Methodology," MITRE Technical Report, September 1977.

29. Rogers, Everett M. and Floyd Shoemaker, The Communication of Innovations, (New York: The Free Press, 1971).

30. Rogers, Everett M., Diffusion of Innovation, (New York: The Free Press, 1962).

31. Ryan, Bruce and Neal Gross, "Using the Diffusion Theory to Improve Marketing Planning," Industrial Marketing, July 1977, p. 107.

32. Schiffel, D., D. Costello, D. Posner, and R. Witholder, "The Market Penetration of Solar Energy: A SPURR Model Review Workshop Summary," Solar Energy Research Institute draft paper, 1977.

33. Scott, Jerome E., Consumer Demand Analysis: Solar Heating and Cooling of Buildings Final Report, September 1976.

34. SRI International, "A Comparative Evaluation of Solar Alternatives: Implementation for Federal R,D and D," Vols. I and II, January 1978.

35. Warren, E.H., Jr., "Solar Energy Market Penetration Analysis: A Review and Critique," presented at the Joint TIMS/ORSA Meeting, May 1979.

36. White, David C., "Energy Choices for the 1980's," Technology Review, August-September 1980, pp. 30-40.

37. Williams, B.F., "Do Photovoltaics Have a Future?" RCA Engineering, February-March 1979, pp. 12-15.

38. Zaltman, G. and Ronald Stiff, "Theories of Diffusion," in S. Ward and T. Robertson (eds.), Consumer Behavior: Theoretical Sources (Englewood Cliffs, New Jersey: Prentice Hall, 1973).

Appendix 1: PV1 Strategy Comparisons

The tables in this appendix present forecasts of market penetration, costs of PV, and costs of government programs for the 15 strategies run on the PV1 computer model. Market penetration figures are measured in cumulative peak kilowatts and are aggregations of PV sales from the six sectors. Both gross and subsidized cost per peak watt of PV are given for each year of the forecast period. In several instances the subsidized cost is higher than expected, given the subsidy rate. This happens because subsidies are subject to a ceiling limit. The government spending column in each of the tables is an aggregate value of annual MD, TD, ARND, advertising and subsidy spending. Cumulative 15-year totals for each category accompany each table.

Market development spending is allocated equally across the residential, commercial, agricultural, industrial and government/institutional sectors in all strategies except Strategy 15. No MD funds are allocated to the central power sector since preliminary model runs have demonstrated that utilities will not adopt PV unless the subsidy ceiling is raised into the millions. For strategy 15, MD funds are split equally between the residential and commercial sectors.

Although the spending strategies for the MD, TD, ARND and advertising options reflect plausible government actions, the subsidy rates used in several strategies are undoubtedly too high, and lead to some large subsidy expenditures. Government has not yet placed limits on subsidy spending, but it can be assumed that some of the cumulative subsidy figures calculated by the PV1 model exceed a realistic budget. Nevertheless, the use of inflated subsidy rates has the advantage of showing how diffusion occurs once it gets going. In the case of strategies with only modest subsidization, where PV does not diffuse all that well, this glimpse is not afforded within the 15-year forecast duration.

A vital model assumption on which all results depend is the timing of the Stage 2 and Stage 3 technologies. Clearly, if the time until these technologies arrive is shortened, then diffusion will be speeded up; if it is longer than expected then diffusion will be slowed. Note that, except for the baseline strategy, the allocations of TD and ARND funds, which determine Stage 2 and Stage 3 arrival dates, were kept the same for each strategy ($400 million for TD, $700 for ARND). For all models, these funds were spent at double the rate of the most likely annual amount so to hasten the arrivals of the advanced technologies. Had they been spent at a slower rate, some of the more interesting diffusion effects which occur late in the forecasts would have been delayed and missed. Using the terminology of Section 5.4g, the specifications of Stage 2 and Stage 3 arrival dates are as follows.

	Stage 2	Stage 3
t_0	3	6
t_1	6	10
t_2	12	30
t_3	4	7
D_1	50	40

The uninstalled cost per peak watt of PV at Stage 3 was set to the 1986 DOE target of $.70.

Finally, it is important to remember that deviations in input variables that are held constant in these analyses (e.g., the efficiency of the PV cell, set at 12%) might cause different results. All such variables were provided with either objective data or best estimate input values.

Table A-1

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt: sub	Average Cost Per Peak Watt: gross	Government Spending (millions)
1	384	15.33	15.33	6.00
2	921	43.44	43.44	6.00
3	1882	32.45	32.45	6.00
4	4121	20.40	20.40	6.00
5	9520	11.93	11.93	6.00
6	17755	8.02	8.02	6.00
7	28336	6.93	6.93	6.00
8	40746	6.52	6.52	6.00
9	54563	6.28	6.28	6.00
10	69550	6.13	6.13	6.00
11	85516	6.03	6.03	6.00
12	103575	2.12	2.12	6.00
13	122339	2.07	2.07	6.00
14	141593	2.07	2.07	6.00
15	161279	2.07	2.07	6.00

Cumulative MD spending (millions) = 75.00
Cumulative government TD spending (millions) = 0.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 0.00
Cumulative subsidy spending (millions) = 0.00
Cumulative advertising spending (millions) = 15.00
Percent of cumulative penetration that is private = 0.9121

Description of Strategy: Strategy 1

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-15	5	1-15	0	1-15	0

Year	Subsidy Rate
1-15	0

Electricity rate rise = .03

Table A-2

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	gross	Government Spending (millions)
1	334	15.33	15.33	206.00
2	921	43.44	43.44	206.00
3	1832	32.45	32.45	206.00
4	4121	20.40	20.40	205.00
5	9735	3.78	3.78	106.00
6	18613	3.61	3.61	105.00
7	29802	3.41	3.41	106.00
8	43455	2.20	2.20	6.00
9	53582	2.15	2.15	6.00
10	74879	2.14	2.14	6.00
11	92147	2.12	2.12	6.00
12	110214	2.10	2.10	6.00
13	128933	2.09	2.09	6.00
14	148186	2.08	2.08	6.00
15	167383	2.07	2.07	6.00

Cumulative MD spending (millions) = 75.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARMD spending (millions) = 700.00
Cumulative subsidy spending (millions) = 0.00
Cumulative advertising spending (millions) = 15.00
Percent of cumulative penetration that is private = 0.3691

Description of Strategy: Strategy 2

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-15	5	1-4	100	1-7	100
		5-15	0	8-15	0

Year	Subsidy Rate
1-15	0

Electricity rate rise = .03

Table A-3

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	Average Cost Per Peak Watt gross	Government Spending (millions)
1	384	12.44	15.33	206.13
2	922	40.50	43.43	206.97
3	1838	29.56	32.40	208.01
4	4359	17.25	20.20	212.42
5	10477	2.26	3.77	113.23
6	19649	2.16	3.60	117.19
7	30879	2.05	3.42	119.34
8	44535	1.32	2.21	16.05
9	59573	1.29	2.15	17.02
10	75975	1.28	2.14	17.92
11	93244	1.27	2.12	18.61
12	111305	1.26	2.10	19.17
13	130015	1.25	2.08	19.51
14	149256	1.25	2.08	19.97
15	168242	1.23	2.05	18.73

Cumulative MD spending (millions) = 75.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 141.31
Cumulative advertising spending (millions) = 15.00
Percent of cumulative penetration that is private = 0.8717

Description of Strategy: Strategy 3

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-15	5	1-4	100	1-7	100
		5-15	0	8-15	0

Year	Subsidy Rate
1-15	.40

Electricity rate rise = .03

Table A-4

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt: sub	Average Cost Per Peak Watt: gross	Government Spending (millions)
1	284	11.39	15.33	206.13
2	922	39.69	43.43	207.01
3	1898	29.03	32.40	208.23
4	4359	16.25	20.20	214.47
5	10477	1.35	3.77	117.59
6	19682	1.24	3.50	124.52
7	31429	1.08	3.42	130.22
8	57263	0.45	2.25	48.73
9	110533	0.40	2.01	87.55
10	215153	0.31	1.54	131.25
11	411843	0.23	1.39	220.93
12	768308	0.25	1.25	359.33
13	1393801	0.23	1.13	557.05
14	2450132	0.20	1.02	368.21
15	4231105	0.18	0.91	1234.69

Cumulative MD spending (millions) = 75.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 3586.58
Cumulative advertising spending (millions) = 15.00
Percent of cumulative penetration that is private = 0.9934

Description of Strategy: Strategy 4

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-15	5	1-4	100	1-7	100
		5-15	0	8-15	0

Year	Subsidy Rate
1-15	.3

Electricity rate rise = .03

Table A-5

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt		Government Spending (millions)
		sub	gross	
1	334	12.22	15.33	206.13
2	922	40.97	43.43	205.95
3	1864	29.93	32.41	207.81
4	4245	17.89	20.75	212.01
5	11057	0.33	3.92	126.83
6	27823	0.13	3.39	157.47
7	55555	0.07	2.79	205.65
8	146109	0.05	1.60	126.35
9	309509	0.00	1.73	283.34
10	626646	0.00	1.55	475.12
11	665822	0.79	1.32	25.23
12	686930	1.34	2.23	22.01
13	707691	1.28	2.14	21.69
14	723819	1.23	2.06	21.38
15	750242	1.23	2.05	21.55

Cumulative MD spending (millions) = 75.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 1125.62
Cumulative advertising spending (millions) = 15.00
Percent of cumulative penetration that is private = 0.0031

Description of Strategy: Strategy 5

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-15	5	1-4	100	1-7	100
		5-15	0	8-15	0

Year	Subsidy Rate
1-10	1.0
11-15	.4

Electricity rate rise = .03

Table A-6

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt		Government Spending (millions)
		sub.	gross	
1	3803	15.33	15.33	250.00
2	12098	9.27	9.27	250.00
3	28094	6.83	6.83	250.00
4	47316	6.03	6.03	250.00
5	75963	3.30	3.30	150.00
6	105128	3.17	3.17	150.00
7	136398	3.22	3.22	150.00
8	176704	2.05	2.05	60.00
9	213895	1.94	1.94	60.00
10	250360	1.97	1.97	60.00
11	273619	1.90	1.90	0.00
12	296465	2.16	2.16	0.00
13	314553	2.04	2.04	0.00
14	332376	2.04	2.04	0.00
15	351397	2.03	2.03	0.00

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARMD spending (millions) = 700.00
Cumulative subsidy spending (millions) = 0.00
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.5937

Description of Strategy: Strategy 6

Annual Spending (millions)

Year	MD	Year	TD	Year	ARMD
1-15	50	1-4	100	1-7	100
11-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-15	0

Electricity rate rise = .03

Table A-7

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	Average Cost Per Peak Watt gross	Government Spending (millions)
1	3800	12.21	15.33	261.24
2	12619	6.39	9.26	267.58
3	42740	0.97	7.05	420.34
4	126231	0.35	5.19	639.40
5	337386	0.09	2.64	663.16
6	439433	0.53	2.30	300.00
7	487020	0.69	2.94	230.71
8	600585	0.42	2.09	209.60
9	847961	0.32	1.58	332.39
10	1345847	0.24	1.15	495.50
11	1414301	0.70	1.17	31.89
12	1433760	1.23	2.10	15.34
13	1452873	1.27	2.12	15.17
14	1472211	1.22	2.03	15.37
15	1491755	1.22	2.03	15.85

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 2225.44
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.0940

Description of Strategy: Strategy 7

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-10	50	1-4	100	1-7	100
11-15	0	5-11	0	8-15	0

Year	Subsidy Rate
1-5	1.0
6-10	.8
11-15	.4

Electricity rate rise = .03

Table A-8

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt: sub	Average Cost Per Peak Watt: gross	Government Spending (millions)
1	7553	12.20	15.33	322.34
2	41807	1.69	7.42	472.07
3	148570	0.49	5.15	756.87
4	430988	0.20	4.40	1452.99
5	1116762	0.05	2.04	1505.93
6	1274170	0.39	1.89	335.68
7	1306543	0.30	3.05	172.63
8	1373950	0.45	2.27	122.47
9	1508754	0.34	1.70	133.29
10	1758490	0.26	1.29	263.30
11	1805335	0.97	1.61	23.75
12	1824673	1.13	1.89	14.61
13	1844177	1.25	2.09	16.28
14	1863850	1.21	2.02	15.93
15	1883688	1.21	2.02	16.03

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 3939.17
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9514

Description of Strategy: Strategy 3

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-5	100	1-4	100	1-7	100
6-15	0	5-11	0	3-15	0

Year	Subsidy Rate
1-5	1.0
6-10	.8
11-15	.4

Electricity rate rise = .03

Table A-9

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt		Government Spending (millions)
		sub	gross	
1	3809	12.21	15.33	261.24
2	12019	6.39	9.26	267.33
3	42748	0.97	7.05	420.34
4	126231	0.35	5.19	639.40
5	337386	0.09	2.64	663.16
6	616332	0.47	2.19	602.46
7	969645	0.48	2.28	760.62
8	1724327	0.28	1.39	859.23
9	3248289	0.22	1.10	1365.64
10	5928955	0.16	0.82	1769.05
11	7739385	0.41	0.68	489.17
12	8946924	0.56	0.93	450.12
13	10130729	0.62	1.03	437.92
14	11706740	0.58	0.96	604.50
15	13750316	0.51	0.85	690.38

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 8632.23
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9802

Description of Strategy: Strategy 9

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-10	50	1-4	100	1-7	100
11-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-5	1.0
6-10	.8
11-15	.4

Electricity rate rise = .10

Table A-10

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	Average Cost Per Peak Watt gross	Government Spending (millions)
1	7558	12.20	15.33	322.34
2	41807	1.69	7.42	472.07
3	148571	0.49	5.15	756.88
4	178661	2.75	5.18	344.20
5	230142	0.85	3.30	274.26
6	332247	0.61	2.87	330.76
7	554209	0.58	2.68	556.00
8	1016355	0.27	1.35	503.70
9	1940686	0.47	1.17	648.17
10	3721425	0.35	0.83	942.75
11	5991147	0.30	0.75	1027.72
12	8341541	0.32	0.79	1120.96
13	10734971	0.34	0.84	1207.17
14	13187432	0.34	0.35	1246.17
15	15685459	0.34	0.35	1257.22

Cumulative RD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 9341.01
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.0944

Description of Strategy: Strategy 10

Annual Spending (millions)

Year	RD	Year	TD	Year	ARND
1-5	100	1-4	100	1-7	100
6-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-3	1.0
4-8	.8
9-15	.6

Electricity rate rise = .10

Table A-11

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt: sub	Average Cost Per Peak Watt: gross	Government Spending (millions)
1	7558	12.20	15.33	322.34
2	41807	1.69	7.42	472.07
3	94214	1.74	5.35	460.06
4	125621	2.73	5.22	349.05
6	179144	0.91	3.36	230.07
6	291104	0.60	2.79	346.10
7	520630	0.57	2.64	574.75
8	787704	0.50	1.20	166.00
9	949392	0.78	1.29	83.56
10	1043363	0.97	1.62	60.37
11	1061636	1.92	1.92	0.00
12	1080035	2.10	2.10	0.00
13	1093333	2.04	2.04	0.00
14	1118095	2.03	2.03	0.00
15	1139410	2.05	2.05	0.00

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARMD spending (millions) = 700.00
Cumulative subsidy spending (millions) = 1400.92
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9235

Description of Strategy: Strategy 11

Annual Spending (millions)

Year	MD	Year	TD	Year	ARMD
1-5	100	1-4	100	1-7	100
6-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-2	1.0
3	.9
4-7	.8
8	.5
9-10	.4
11-15	0

Electricity rate rise = .10

Table A-12

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt		Government Spending (millions)
		sub	gross	
1	7558	12.20	15.33	322.34
2	41007	1.09	7.42	472.07
3	94214	1.74	5.35	450.00
4	125621	2.73	5.22	349.06
5	179144	0.91	3.36	280.07
6	291184	0.60	2.79	345.18
7	520630	0.57	2.64	574.75
8	787794	0.60	1.20	150.00
9	949392	0.78	1.29	83.58
10	1043363	0.97	1.62	60.67
11	1137805	1.07	1.79	67.56
12	1307980	0.97	1.61	109.71
13	1505650	0.84	1.40	167.16
14	2112299	0.59	1.15	233.83
15	2953253	0.62	1.04	349.02

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 2336.25
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.0705

Description of Strategy: Strategy 12

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-5	100	1-4	100	1-7	100
5-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-2	1.0
3	.9
4-7	.8
8	.5
9-15	.4

Electricity rate rise = .10

Table A-13

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt		Government Spending (millions)
		sub	gross	
1	36314	12.17	15.33	808.3[illegible]
2	133774	0.06	5.47	754.72
3	215646	0.92	4.56	479.82
4	230162	2.32	5.26	234.09
5	250632	0.94	3.47	151.76
6	297229	0.75	3.28	217.55
7	398525	0.62	2.86	327.26
8	575236	0.64	1.28	112.89
9	731195	0.74	1.24	77.25
10	856018	0.89	1.49	74.27
11	1032592	0.95	1.58	111.70
12	1350759	0.87	1.45	183.90
13	1907299	0.67	1.12	250.11
14	2854557	0.59	0.99	375.47
15	4426856	0.54	0.90	566.02

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 3025.21
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9926

Description of Strategy: Strategy 13

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1-5	500	1-4	100	1-7	100
6-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-2	1.0
3	.9
4-7	.8
8	.5
9-15	.4

Electricity rate rise = .10

Table A-14

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	gross	Government Spending (millions)
1	36313	15.33	15.33	800.00
2	44743	5.38	5.38	200.00
3	54624	7.17	7.17	200.00
4	66343	6.61	6.61	200.00
5	79692	3.33	3.33	100.00
6	94331	1.00	3.29	133.50
7	112187	0.95	3.32	142.33
8	149357	0.42	2.09	62.26
9	223727	0.38	1.92	114.15
10	330059	0.92	1.54	65.47
11	527919	0.88	1.46	115.54
12	884441	0.75	1.25	173.04
13	1503073	0.67	1.11	276.52
14	2559524	0.59	0.99	419.99
15	4331365	0.54	0.89	528.55

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 1936.64
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9925

Description of Strategy: Strategy 14

Annual Spending (millions)

Year	MD	Year	TD	Year	ARND
1	500	1-4	100	1-7	100
2-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-5	0
6-9	.8
10-15	.4

Electricity rate rise = .10

Table A-15

Summary of Results

Year	Cumulative Installed Peak KW	Average Cost Per Peak Watt sub	Average Cost Per Peak Watt gross	Government Spending (millions)
1	7973	10.97	15.33	323.32
2	44164	0.96	7.04	474.04
3	99397	1.24	5.13	468.85
4	129436	2.15	4.96	342.24
5	192794	0.73	3.26	300.53
6	337021	0.54	2.62	400.53
7	650551	0.48	2.35	684.66
8	1126274	0.54	1.08	257.98
9	1511825	0.63	1.05	161.29
10	1794993	0.74	1.24	140.25
11	2087040	0.80	1.34	156.57
12	2613269	0.76	1.26	265.55
13	3533753	0.60	1.01	370.08
14	5100431	0.52	0.87	546.83
15	7336060	0.48	0.79	710.27

Cumulative MD spending (millions) = 500.00
Cumulative government TD spending (millions) = 400.00
Cumulative private TD spending (millions) = 0.00
Cumulative ARND spending (millions) = 700.00
Cumulative subsidy spending (millions) = 3903.12
Cumulative advertising spending (millions) = 100.00
Percent of cumulative penetration that is private = 0.9874

<u>Description of Strategy</u>: Strategy 15 (Sectoral Concentration)

<u>Annual Spending (millions)</u>

Year	MD	Year	TD	Year	ARND
1-5	100*	1-4	100	1-7	100
2-15	0	5-15	0	8-15	0

Year	Subsidy Rate
1-2	1.0
3	.9
4-7	.8
8	.5
9-15	.4

Electricity rate rise = .10

*Funds are allocated equally and totally to the residential and commercial sectors.

Appendix 2: Questionnaires for Residential Field Data Collection

RESPONDENT # ________ (1 - 4)

IV 115

TELEPHONE QUESTIONNAIRE FOR PHOTOVOLTAICS

Screener

Date ____________________

Hello, my name is ____________. I'm calling you for ______________________ an independent market research firm. We're working with the Sloan School of Management at MIT to conduct a survey about solar energy.

I'd like to ask you a few brief questions.

A. First, in order to determine if you qualify for the study, would you please tell me if you reside in any of the following communities. Do you live in: (READ LIST)

GREEN (5)	Yes	No
Arlington	1	R
Bedford	2	R
Belmont	3	R
Burlington	4	R
Lexington	5	R
Lincoln	6	R

YELLOW (6)	Yes	No
Norword	1	R
Medfield	2	R
Westwood	3	R
Sherborn	4	R
Dover	5	R
Needham	6	R
Dedham	7	R
Walpole	8	R

(IF "NO" TO ALL CITIES, TERMINATE)

1. Do you currently own a home? 7 __

   Yes ____-1 No ____-2 (TERMINATE)

2. Does your home use electric power for home heating? 8 __

   Yes ____-1 No ____-2

3. Are you the person who makes most of the decisions about things like the heating, the plumbing and the electrical systems in your home?

   (IF NOT: ASK TO SPEAK TO THE PERSON WHO IS AND REPEAT, "Hello, my name is ____________. I'm calling you for ______________________ an independent market research firm.")

   We're conducting a study about solar energy and I'd like to ask you to participate. Its results will be used in the development of energy policy.

   Let me tell you how the survey works. First, I'll ask you a few questions over the telephone. That will take about ten minutes. When we're done, I'll mail you some information about solar energy systems. This material will also include a questionnaire. We ask you to read through the material that is sent and to discuss it with your family. Then, we'd like you to complete the questionnaire and return it in a prepaid return envelope.

I'll call you back again, in about a week, to answer any questions you may have about the questionnaire.

Our study is based on only a few hundred respondents, and it's very importa that we get a representative sample of households. In addition, most people who have already completed the survey have found it to be both interesting and informative. For these reasons I'd really like you to agree to take part. Are there any questions that you might have about the study? Will you participate?

(IF NECESSARY): Of course, any information you will provide will be combined with all the other responses and will be used for statistical analysis only. Your participation will be completely confidential and your name will never be associated with this survey in any way.

Yes _____ No _____ (GO TO DEMOGRAPHICS AND TERMINATE)

Terrific! Let me first take your name and address so that I can mail out the package of information.

Name ________________________________
(9-25)

(PRINT CLEARLY! SOMEONE HAS TO COPY THIS OVER!)

Address ________________________________
(26-45)

City ____________________ State ______ Zip ________
(46-59) (61-62) (64-68)

Telephone Number ________________________

80-1
Card 2 Duplicate 1-4

You will be receiving the information about solar energy equipment in a week or so. We'd like you to read the material, and to discuss it with your family if you think that would be appropriate. Enclosed with the literature will be some questions about the information presented. We would like you to complete the questionnaire and return it to us in the postage paid return envelope that will accompany it. I will be calling you back in about a week to answer specific questions you might have about the survey. If you don't have any questions, and can complete and mail the survey before I call again, please do so.

INTERVIEWER NAME: ________________________

TIME START __________ TIME END __________

Now, Mr./Mrs. ______________, let me ask you the first set of questions. To start with, ...

TELEPHONE QUESTIONNAIRE FOR PHOTOVOLTAICS

1. Are you currently using any kind of solar energy system in your home?

   Yes _____-1 No _____-2 (SKIP TO Q. 2)

1a. For what purpose are you using your solar energy system?

   Water Heating _____-1 **(If only water heating, skip to Q. 7)**

   Space Heating _____-2

   Both Water and Space Heating ____-3

   Other (specify) ______________________________-4

1b. Do you have an active or a passive solar energy system?

   Active ____-1 (SKIP TO Q. 6a)
   Passive ____-2 (CONTINUE WITH Q. 2)
   Both ____-3 (SKIP TO Q. 6a)
   Uncertain ____ (NOTE: IF RESPONDENT IS UNCERTAIN, ASK): Could you please describe how your solar system works? **(Then continue with Q. 2))**

   ____

   ____

   ____

2. Other than in a picture, have you ever seen a home equipped with solar collectors or solar panels?

   YES _____-1 NO_____-2 NOT SURE _____-3

   (IF "PASSIVE" IS CHECKED IN Q. 1b, SKIP TO Q. 6a)

3. Do you know anyone who is <u>now</u> using solar energy for home or water heating?

   YES _____-1 NO_____-2 NOT SURE _____-3

4. Have you actually gone looking for information about solar home or water heating equipment from a solar equipment manufacturer or dealer, a builder or an architect?

   YES _____-1 NO_____-2

5. Are you likely or unlikely to have an active solar home or water heating system installed in your home in the next year? (AS NECESSARY): Is that very likely/unlikely or somewhat likely/unlikely? And how about within the next 5 years? (AS NECESSARY): Is that very likely/unlikely or somewhat likely/unlikely?

	Next Year	Next 5 Years
Very likely	____-1	____-1
Somewhat likely	____-2	____-2
Unsure	____-3	____-3
Somewhat unlikely	____-4	____-4
Very unlikely	____-5	____-5

(SKIP TO Q. 7)

6a. About what percentage of your <u>total</u> heating needs are supplied by your solar heating system(s)?

______%

(IF "BOTH" IS CHECKED IN Q. 1b, ASK 6b. OTHERWISE SKIP TO Q. 7)

6b. And about what percentage of your <u>total</u> heating needs are supplied by the <u>passive portion</u> of your solar heating system <u>alone</u>?

______% (NOTE RESPONSE MUST BE SMALLER THAN RESPONSE TO Q. 6a)

7. Now, I'd like to ask you a few questions about a different kind of solar energy system. This system turns the energy of sunlight into electricity rather than heat. It is usually called a photovoltaic (FOE-TOE-VOLE-TAY'-IC) power system or a PV (PEE-VEE) system for short.

Prior to this survey, had you ever seen or heard anything about the use of PV power systems that generate electricity for use in your <u>home</u>?

Yes ____-1 No ____ -2 (SKIP TO QUESTION 15)

8. In your area can you currently buy photovoltaic power systems?

Yes ____-1 No ____-2 Uncertain ____-3

9. Have you heard of any kinds of government sponsored financial incentives to home owners who install PV power systems?

Yes ____-1 No ____-2 Uncertain ____-3

10. Would you agree or disagree with the statement, "I understand the financial aspects of PV power systems". (AS NECESSARY): Would that be strongly agree/disagree or moderately agree/disagree?

Strongly agree	____-5
Moderately agree	____-4
Unsure; don't know	____-3
Moderately disagree	____-2
Strongly disagree	____-1

11. And would you agree or disagree with the statement, "I understand how PV power system work." (AS NECESSARY): Would that be strongly agree/disagree or moderately agree/disagree?

Strongly agree	_____	-5
Moderately agree	_____	-4
Unsure, DK	_____	-3
Moderately disagree	_____	-2
Strongly disagree	_____	-1

12. Do you believe that you can or cannot currently obtain reliable and dependable PV power systems for home use? (AS NECESSARY): Is that definitely can/cannot or probably can/cannot?

Definitely can	_____	-5
Probably can	_____	-4
Unsure, DK	_____	-3
Probably cannot	_____	-2
Definitely cannot	_____	-1

13. Do you believe that you can or cannot currently obtain a PV power system that makes economic sense for home use? (AS NECESSARY): Is that definitely can/cannot or probably can/cannot?

Definitely can	_____	-5
Probably can	_____	-4
Unsure, DK	_____	-3
Probably cannot	_____	-2
Definitely cannot	_____	-1

14. Do you believe that PV power systems will or will not be widely used by homeowners in your area within the next five years? (AS NECESSARY): Is that definitely will/will not or probably will/will not?

Definitely will	_____	-5
Probably will	_____	-4
Unsure, DK	_____	-3
Probably will not	_____	-2
Definitely will not	_____	-1

Next, I have a few questions about your home and home energy usage.

15. How old is your home? (READ LIST)

0 - 5 years	______-1	21 - 40 years	______-4
6 - 10 years	______-2	over 40 years	______-5
11 - 20 years	______-3	dk/refused	______-6

16. a. Does your home have insulation in the ceiling?

Yes ______ -1
No ______ -2
Don't know ______ -3 —(SKIP TO Q. 16)

b. How much ceiling insulation does your home have? (READ LIST)

1 - 3 inches	______-1	10 - 12 inches	______ -4
4 - 6 inches	______-2	over 12 inches	______ -5
7 - 9 inches	______-3	Don't know	______ -6

17. Does your home have insulation in the walls?

Yes ______ -1

No ______ -2

Don't know ______ -3

18. Does your home have storm windows or the equivalent (therma-pane windows)? (READ LIST)

25__ 26__

Yes ______-1 → (IF YES:) on all windows? ______-1

on most windows? ______-2

on a few windows? ______-3

No ______-2

Don't know ______-3

19. a. Do you have natural gas service available on your street?

Yes ______ -1 No ______ -2 Don't know ______ -3

b. Do you have propane delivery service in your neighborhood?

Yes ______ -1 No ______ -2 Don't know ______-3

c. Do you have home heating oil delivery service in your neighborhood?

Yes ______-1 No ______ -2 Don't know ______-3

20. What fuel do you use for most of your cooking?

Electricity ______ -1 Gas ________-2 Propane ______-3

Other (specify) ____________________-4 Do not own ______-5

21a. What is the primary fuel that you use to heat your home? Is it: (READ LIST) (CHECK ONLY ONE RESPONSE)

Electricity: Is that: with baseboard radiant heat __-1
with heat pump __-2

Natural gas __-3
Propane __-4
Oil __-5
Coal __-6
Wood __-7
Solar energy __-8 (IF "Solar" is mentioned, ask Q20b; otherwise, go to Q20c)
something other than these (specify) ____________
________ __ 9

Do not own __-10

21b. About how old is your primary heating system? Is it: (READ LIST)

0-5 years ___-1 21-40 years ___-4
6-10 years ___-2 over 40 years ___-5
11-21 years ___-3 dk/refused ___-6

22. What is the primary fuel that you use to heat water for showers and baths, dishwashing, and so on?

Electricity ___-1 Gas ___-2 Oil ___-3 Propane ___-4
Solar ___-5 Other (specify)________-6 Do not know___-7

23a. Does your home have a central air conditioning system?

YES ____ -1 NO____-2

23b. Does your home have individual, room air conditioning units?

YES____-1 NO____-2
(If YES): How many units? ____

24. Approximately how much do you pay per month for electricity in ...

The summer $_______ the winter $_______
(If Don't Know, try to have respondent guess)
(READ FOR RESPONDENTS WHO WILL NOT PARTICIPATE):

In order to be certain that we are interviewing a cross section of people I would like to ask you a few statistical questions before we terminate.

Demographics

25. Finally, I would like to get a little more information about you and your household for classification purposes. Please tell me into which of the following age groups you fall? (READ LIST)

under 25	____-1
25 - 34	____-2
35 - 44	____-3
45 - 54	____-4
over 55	____-5

26. What was the highest level of schooling you completed? Was it: (READ LIST)

Grammar school	____-1
High school	____-2
College	____-3
Post-graduate work or degree	____-4

27. Including yourself, how many people live in your home?

____

28. How many are: (READ)

Adults 18 or over ____

Children under 18 ____

29. Which of the following categories best describes your family's composition?

You have children living at home with the youngest under age 6	___-1
You have children living at home with the youngest age 6 to 12	___-2
You have children living at home with the youngest age 13 to 18	___-3
You have no children living at home under the age of 19	___-4

30. How many members of your household, including yourself, work outside the home for 30 hours or more per week?

____

31\. Finally, it would help us a great deal in our statistical analysis if we could get some idea about your income level. Was your <u>total household income</u> for last year, before taxes, under or over $25,000?

If "under"		If "over"	
Would that be under or over $15,000?		Would that be under of over $40,000?	
under	over	under	over
_____-1	_____-2	_____-3	_____-4

32\. (RECORD SEX:) Male _____-1 Female _____-2

(IF AGREED TO PARTICIPATE:)
Once again, thank you for agreeing to participate in this study. I'll get the material in the mail soon and you should have it in a week or ten days. I'll talk to you again in about two weeks.

(IF <u>DID</u> <u>NOT</u> AGREE TO PARTICIPATE:)
Thank you very much for your time.

(STAPLE TO SCREENER QUESTIONNAIRE)

(IF REFUSED TO ANSWER QUESTIONS 25, 26 or 31- DO NOT COUNT TOWARD QUOTA)

Interview: At Site ____-1

Massachusetts Institute of Technology
Alfred P. Sloan School of Management
50 Memorial Drive
Cambridge, Massachusetts, 02139

Dear Study Participant:

In this booklet you will find information about photovoltaic (PV) power systems. The description of the system is followed by a series of questions which relate to that particular description. A few of the questions here ask for information about your household energy usage. If you can, please use your records to answer these questions as accurately as possible. If you are unable to determine these answers exactly, please make an estimate. Other questions call for you to guess about the future, or ask for your opinions. On these kinds of questions there are no right or wrong answers, so just try to respond in a way that reflects your beliefs as accurately as possible.

We will be calling you back in a few days to answer specific questions you might have about the survey. If you don't have any questions, and can complete the survey before we call again, please do so.

Thank you very much for your help!

Sincerely,

Gary L. Lilien
Associate Professor of
Management Science.

GLL:dms

PHOTOVOLTAICS SYSTEM FOR HOMES IN THE GREATER BOSTON AREA

The energy of sunlight can be converted into electrical energy for your home by means of a photovoltaic (PV for short) generating system. Such a system is composed of modular panels covered with interconnected "solar cells" and a piece of electrical equipment called a "power inverter." When sunlight strikes the solar cells, an energy reaction takes place because of the special internal structure of the cells. The energy reaction produces electricity which is drawn off through wires attached to the cells, and sent to the power inverter. One of the tasks of the power inverter is then to "invert" the electricity (from DC to AC) so that it can be used in the home.

As long as the sun is shining, the PV system will continue to supply electricity to the home. However, the house still remains connected to the local utility company's power supply. At night, or when the weather is cloudy, the power inverter automatically switches the house over to utility-generated power. On the other hand, when electricity produced by the home's PV system is not being fully utilized (during the daytime or when the family is on vacation), the power inverter sends whatever energy is extra back to the utility company. (See Figure 1.) The home is then credited for energy sold to the company, but at a rate of 60% of the utility company's regular prices because of the cost involved in transferring the surplus power to other areas.

Most homes would need several solar cell panels. The number of panels you would need depends on how much utility-generated electricity you would like to displace. Because the solar cell panels are modular, you can install enough solar cells to provide whatever fraction of your electric power needs you wish. The panels can be mounted on your roof or installed in your yard. For example, you might choose a system that would provide for your home's electric power needs except for hot water, space heating and air conditioning. In that case, any additional electricity needed for those purposes would be provided automatically by the utility company at the normal rate. Of course you could install a larger PV system that would provide for all of your home's electric power needs and reduce your utility bills to zero. If you increase the system size beyond that point you could actually be selling power to the utility company on a regular basis, and would receive payments from the utility.

A photovoltaic system comes with a 5-year manufacturer's warranty. Panels are tested to ensure that they will withstand all possible climate extremes in the area in which they are to be installed. The system has an expected life of 20 years which is comparable to the expected life of typical roofing material. A diagram of a photovoltaic system is shown in Figure 2.

Figure 1: POWER USAGE IN THE AVERAGE HOME (seasonal average)

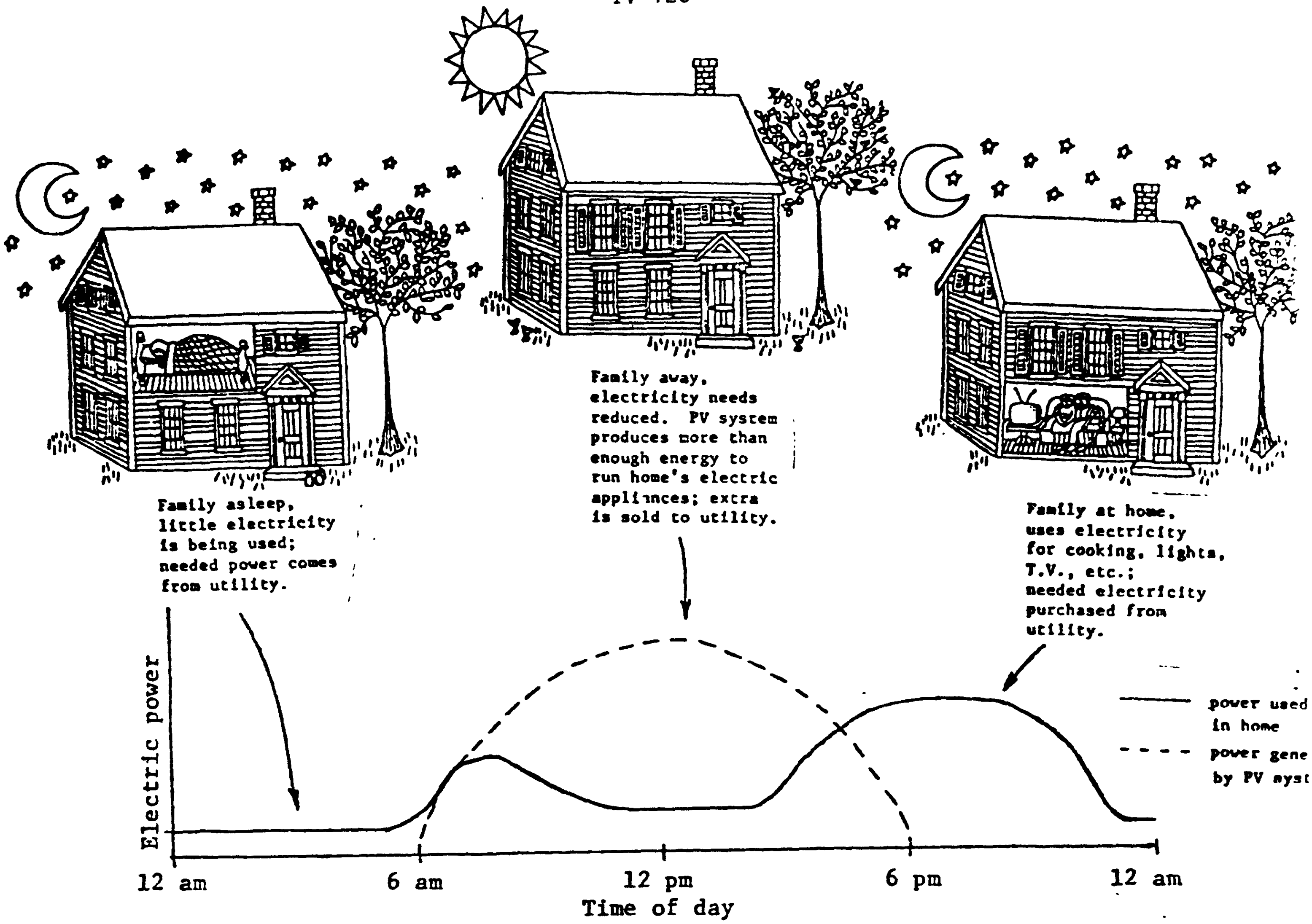
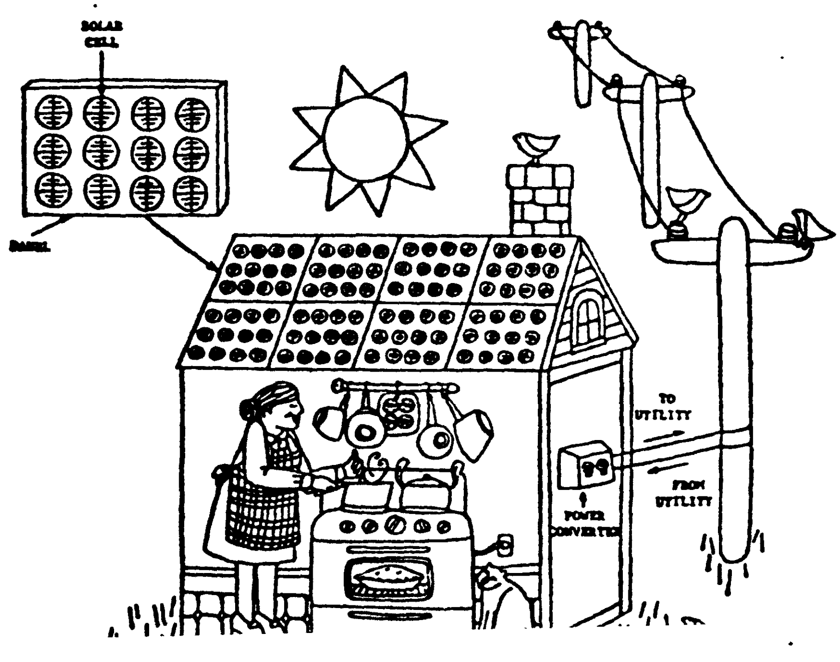


Figure 2: A TYPICAL PHOTOVOLTAIC SYSTEM FOR THE HOME



PHOTOVOLTAIC (PV) POWER SYSTEM FOR MASSACHUSETTS HOMES

A FINANCIAL EXAMPLE

The table on the following page shows financial information associated with owning and operating a PV system. The top row of the table shows various dollar amounts of utility-generated electricity that can be displaced by the system. The second row shows the size of the PV system needed to displace that much electricity. The system that is most appropriate for you thus depends on how much utility-generated electricity you wish to displace, and on the size of the system your property can accomodate. For example, if you wish to displace about $50/month, you would need a system that measures about 500 $ft.^2$. Looking further down in the column, you can see that a system of this size has a gross cost of $8,600, but you would get a tax rebate of $4,440, so the actual price of such a system would be $4,160.

This system saves $600 the first year after it is installed. Because of expected inflation the system will save more each year, until, in the 5th year, it saves $875, as the table shows. If you add up the yearly savings for 5½ years, the sum equals the actual price of the system, so the system "pays back" in 5½ years.

<u>PRICE AND TAX REBATES</u>: The gross price of a photovoltaic system for your home would depend on the size of the system as the table shows. The prices shown include materials and installation. However, the federal government and the state of Massachusetts offer refunds, paid to you as lump sums subtracted from your income taxes. (The tax rebate may be spread out over as many years as you need.) The actual cost to you would thus be lower than the gross price. For example, if you purchased a system costing $10,000 you would be eligible for $5,000 in tax rebates:

	Gross Price	$10,000
(minus)	tax rebate	5,000
	Actual Price	$ 5,000

<u>SAVINGS:</u> Because of inflation, the cost of electricity will increase as the years go by. But since sunshine remains free, the savings from a PV system will grow at the same rate. Over the past 10 years, electric energy costs have increased at a rate of 10% per year. The most likely projections would have the rates of increase over the next years be about the same as over the last 10 years, that is, 10%, so the estimates on the next page use that figure. The system will <u>not</u> add any extra cost for maintenance and upkeep.

QUESTIONS ABOUT PHOTOVOLTAIC SYSTEMS

1. Have you seriously considered an alternative system for meeting your electric power needs?

   yes ______ no ______

2. Approximately how much was your electric bill for an average month last year? If you do not know please look it up, or as a last resort, guess. How much do you expect to pay for electricity per month next year? How much do you think you will have to pay per month five years from now (in 1985)?

   last year $_____/month next year $_____/month (guess) in 1985 $_____/month (guess)

3. Assume for a moment that you are going to buy a PV system for your home. Look back at the table in the preceding page, and think about what size system you would be most likely to have installed. (You might want to consider the amount of utility-generated electricity you'd like to displace, displace, the cost of the system and the space you have available to put it.) Approximately what size PV system would you buy?

200 sq. ft. ____	500 sq. ft. ____	800 sq. ft. ____
300 sq. ft ____	600 sq. ft. ____	900 sq. ft. ____
400 sq. ft. ____	700 sq. ft. ____	1000 sq. ft. ____

4. Taking into consideration your family's electric power needs and what you know about PV system prices, government incentives, and your own situation, how much would you expect a system of the size you indicated in Q. 3 would cost you, if you were to buy one? Please check the number that comes closest to your estimate.

Actual price to you, after applicable tax rebates:	$1,000 ____	$6,000 ____	$11,000 ____
	$2,000 ____	$7,000 ____	$12,000 ____
	$3,000 ____	$8,000 ____	$13,000 ____
	$4,000 ____	$9,000 ____	$14,000 ____
	$5,000 ____	$10,000 ____	$15,000 ____
			over $15,000 ____

5. If you were to install a photovoltaic system in your home now, for the price you indicated in Question 4, about how much less would you spend on electric power this year than you would spend using the utility company? Please check the number that comes closest to your estimate.

less than $240 ______	about $720 ($60/month) ______
about $240 ($20/month) ______	$780 ($65/month) ______
$300 ($25/month) ______	$840 ($70/month) ______
$360 ($30/month) ______	$900 ($75/month) ______
$420 ($35/month) ______	$960 ($80/month) ______
$480 ($40/month) ______	$1020 ($85/month) ______
$540 ($45/month) ______	$1080 ($90/month) ______
$600 ($50/month) ______	$1140 ($95/month) ______
$660 ($55/month)	$1200 ($100/month)

PV SYSTEM SAVINGS

	Dollars per Month of Utility-Generated Electricity Displaced								
	$20	$30	$40	$50	$60	$70	$80	$90	$100
Approximate Size System Required (in square feet)	200	300	400	500	600	700	800	900	1000
Approximate Cost									
Gross Price	$5,100	$6,300	$7,200	$8,600	$10,000	$11,400	$12,800	$14,100	$15,500
Tax Rebate	3,040	3,520	3,880	4,440	5,000	5,560	6,120	6,640	7,210
Actual Price	$2,060	$2,780	$3,320	$4,160	$5,000	$5,840	$ 6,680	$ 7,460	$ 8,290
Estimated Savings									
First Month	$ 20	$ 30	$ 40	$ 50	$ 60	$ 70	$ 80	$ 90	$ 100
First Year	$ 240	$ 360	$ 480	$ 600	$ 720	840	960	1,080	1,200
Fifth Year	$ 350	$ 525	$ 700	$ 875	$1,050	$1,230	$ 1,406	$ 1,575	$ 1,750
Years to Payback*	6 1/2	6	5 1/2	5 1/2	5 1/2	5 1/2	5 1/2	5 1/2	5

* When sum of yearly savings equals actual price.

Please copy your "Actual Price" from Question 4 here:
This is your BASE PRICE: $__________ BASE PRICE

Please copy your annual savings estimate from Question 5 here. This is your BASE SAVINGS: $__________ BASE SAVINGS

6a. Please look at your BASE PRICE and BASE SAVINGS above. Thinking about your base figures, how likely would you be to buy a photovoltaic system for your home in the next year? Please check the appropriate space:

- Certain, practically certain (99 in 100) ____
- Almost sure (9 in 10) ____
- Very probable (8 in 10) ____
- Probable (7 in 10) ____
- Good possibility (6 in 10) ____
- Fairly good possibility (5 in 10) ____
- Fair possibility (4 in 10) ____
- Some possibility (3 in 10) ____
- Slight possibility (2 in 10) ____
- Very slight possibility (1 in 10) ____
- No chance, almost no chance (0 in 10) ____

6b. Prices for photovoltaic systems may go down. Keeping your BASE SAVINGS (from above) in mind, suppose you could buy a system for 25% less than your BASE PRICE. (The new price of the system would then be 3/4 of your BASE PRICE.) How likely would you be to buy a system <u>in the next year</u>? Please check the appropriate space:

- Certain, practically certain (99 in 100) ____
- Almost sure (9 in 10) ____
- Very probable (8 in 10) ____
- Probable (7 in 10) ____
- Good possibility (6 in 10) ____
- Fairly good possibility (5 in 10) ____
- Fair possibility (4 in 10) ____
- Some possibility (3 in 10) ____
- Slight possibility (2 in 10) ____
- Very slight possibility (1 in 10) ____
- No chance, almost no chance (0 in 10) ____

6c. Again using your BASE SAVINGS from above, suppose that you could buy a PV system for <u>half</u> of your BASE PRICE. How likely would you be to buy a system <u>in the next year</u>? Please check the appropriate space:

- Certain, practically certain (99 in 100) ____
- Almost sure (9 in 10) ____
- Very probable (8 in 10) ____
- Probable (7 in 10) ____
- Good possibility (6 in 10) ____
- Fairly good possibility (5 in 10) ____
- Fair possibility (4 in 10) ____
- Some possibility (3 in 10) ____
- Slight possibility (2 in 10) ____
- Very slight possibility (1 in 10) ____
- No chance, almost no chance (0 in 10) ____

6d. Electricity prices may rise faster than we now expect. Go back to your BASE PRICE from above, but now suppose that your <u>savings</u> are <u>50%</u> more than your estimated BASE SAVINGS. How likely would you be to buy a system <u>in the next year</u>, if you could get these increased savings? Please check the appropriate space:

- Certain, practically certain (99 in 100) ____
- Almost sure (9 in 10) ____
- Very probable (8 in 10) ____
- Probable (7 in 10) ____
- Good possibility (6 in 10) ____
- Fairly good possibility (5 in 10) ____
- Fair possibility (4 in 10) ____
- Some possibility (3 in 10) ____
- Slight possibility (2 in 10) ____
- Very slight possibility (1 in 10) ____
- No chance, almost no chance (0 in 10) ____

6e. Assuming an improved technology in photovoltaics, suppose that the PV system originally described could also satisfy the power demand for heating in winter and air conditioning in summer, as well as year-'round water heating, at your <u>BASE PRICE</u>. How likely would you be to buy a system <u>in the next year</u>? Please check the appropriate space:

- Certain, practically certain (99 in 100) ____
- Almost sure (9 in 10) ____
- Very probable (8 in 10) ____
- Probable (7 in 10) ____
- Good possibility (6 in 10) ____
- Fairly good possibility (5 in 10) ____
- Fair possibility (4 in 10) ____
- Some possibility (3 in 10) ____
- Slight possibility (2 in 10) ____
- Very slight possibility (1 in 10) ____
- No chance, almost no chance (0 in 10) ____

7. Now think about the original PV system as it is available today -- at your BASE PRICE and with BASE SAVINGS -- and consider how likely you would be to purchase such a system in the next year. (This is the answer you gave to Question 6a.)

a. If the manufacturer changed the warranty from 5 years to 20 years, how much more likely would you be to purchase a system in the next year?

Almost certain to buy _____
Much more likely _____
A little more likely _____
Wouldn't change my likelihood _____

b. If the PV system were to come with the original 5-year warranty, but this time the federal government were to back it, how much more likely would you be to purchase a system in the next year?

Almost certain to buy _____
Much more likely _____
A little more likely _____
Wouldn't change my likelihood _____

c. Now, imagine that the PV system could be reduced in size, through technological changes, so that only half the original number of panels would give you your BASE SAVINGS (again at your BASE PRICE). How much more likely would you be to purchase such a system in the next year?

Almost certain to buy _____
Much more likely _____
A little more likely _____
Wouldn't change my likelihood _____

8. Again think back to your BASE PRICE estimate. (This is the answer you gave to Question 4).

a. Did you choose this BASE PRICE system to displace a portion of your home's electrical power needs including heating and air conditioning or to displace all of those needs?

a portion of my home's needs ____ (please answer Q. 8b)

all of my home's needs ____ (please skip to Q. 8c)

b. About how much more than your BASE PRICE would you be willing to pay for a PV system that would displace all of your home's electrical power needs, including heating and air condition?

$0 ___	up to $3000 ___	
up to $1000 ___	up to $4000 ___	over $5000 ___
up to $2000 ___	up to $5000 ___	

c. Now assume that you could buy a PV system that would allow you to be entirely independent of the utility company. You would need some storage capacity for electricity (batteries) and a back-up diesel generator. You would neither buy electricity from nor sell electricity to the utility. In fact the power lines would be removed. Your home would run as a "stand-alone" unit. Would you be interested in this kind of "stand-alone" capability for your home?

yes ____ Please answer Q. 8d.

no ____ Please skip to Q. 9.

d. About how much more than your BASE PRICE would you be willing to pay for a PV system that would give you "stand-alone" capability -- that is, total independence from the utility company?

$0	___	up to $3000	___		
up to $1000	___	up to $4000	___	over $5000	___
up to $2000	___	up to $5000	___		

9. Please answer the following questions about the use of photovoltaic power systems.

a. Do you believe that you can currently obtain a reliable and dependable photovoltaic system for home use?

Definitely can	____
Probably can	____
Unsure	____
Probably can not	____
Definitely can not	____
Dont' know	____

b. Do you believe that you can currently obtain a photovoltaic system that makes economic sense for home use?

Definitely can	____
Probably can	____
Unsure	____
Probably can not	____
Definitely can not	____
Don't know	____

c. Do you believe that photovoltaic systems will or will not be widely used by homeowners in your area within the next five years?

Definitely will	____
Probably will	____
Unsure	____
Probably will not	____
Definitely will not	____
Don't know	____

10. Please indicate, by circling a number on the scale, how strongly you agree or disagree with each of the following statements about photovoltaic (PV) systems:

	Strongly Agree	Agree	Neither Agree nor Disagree	Disagree	Strongly Disagree	Don't Know (Chec
a. I understand the financial aspects of PV systems.	1	2	3	4	5	____
b. I understand how PV systems work.	1	2	3	4	5	____
c. PV systems can provide protection from future energy shortages	1	2	3	4	5	____
d. A PV system will increase the resale value of my home.	1	2	3	4	5	____
e. If a PV system that I had installed failed and needed major repairs or replacement, it would mean a financial disaster for my family.	1	2	3	4	5	____
f. PV collector panels will be unattractive on my house.	1	2	3	4	5	____
g. It is very easy to take a loan to buy a PV system.	1	2	3	4	5	____
h. To me, initial cost is much more important than expected savings in deciding whether or not to purchase a PV system.	1	2	3	4	5	____
i. If a PV system that I have installed gave less savings than I had expected, it would mean a financial disaster for my family.	1	2	3	4	5	____
j. A PV system will protect me from increasing energy costs.	1	2	3	4	5	____
k. I would vote for zoning restrictions to ban PV collector panels from the front of houses in my neighborhood.	1	2	3	4	5	____

10. (continued)

	Strongly Agree	Agree	Neither Agree nor Disagree	Disagree	Strongly Disagree	Don't Know (check
l. Manufacturers of PV systems are mostly small, unstable companies.	1	2	3	4	5	____
m. A PV system will need lots of attention and maintenance.	1	2	3	4	5	____
n. I would admire a neighbor who installed a PV system.	1	2	3	4	5	____
o. Technological advances will soon make currently available PV systems outdated.	1	2	3	4	5	____
p. To me, expected savings is much more important than initial cost in deciding whether or not to purchase a PV system.	1	2	3	4	5	____
q. Electricity is too small a part of my total energy usage for me to consider a PV system.	1	2	3	4	5	____
r. A PV system that malfunctioned might damage my home, or cause danger to my family.	1	2	3	4	5	____

11. a. How likely are you to look for more information about PV systems, <u>within the next few months</u>?

Very likely ____
Somewhat likely ____
Unsure ____
Somewhat unlikely ____
Very unlikely ____

b. How likely would you be to visit a government sponsored open house showing a PV system in operation, if it were located in your town? In Springfield, MA?

In your town		In Springfield, MA	
Very likely	____	Very likely	____
Somewhat likely	____	Somewhat likely	____
Unsure	____	Unsure	____
Somewhat unlikely	____	Somewhat unlikely	____
Very unlikely	____	Very unlikely	____

c. How likely are you to visit a PV dealer to look at the PV systems that are available, <u>in the next few months</u>? <u>In the next 2 years</u>?

Next few months		Next 2 years	
Very likely	____	Very likely	____
Somewhat likely	____	Somewhat likely	____
Unsure	____	Unsure	____
Somewhat unlikely	____	Somewhat unlikely	____
Very unlikely	____	Very unlikely	____

11. d. How likely are you to have a photovoltaic system installed in your home within the next 5 years?

Very likely	_____
Somewhat likely	_____
Unsure	_____
Somewhat unlikely	_____
Very unlikely	_____

12. Please read each of the following statements. Then circle the number on the scale that shows how much <u>more</u> likely you would be to purchase a PV system under the conditions of the statement.

	Almost certain	Much more likely	A little more likely	No more likely
a. If a PV system would protect me from future energy shortages, I'd be _________ to buy one.	1	2	3	4
b. If a PV system would increase the resale value of my home, I'd be ________ to buy one.	1	2	3	4
c. If it were easy to take a loan to buy a PV system, I'd be ________ to buy one.	1	2	3	4
d. If a PV system would protect me from increasing energy costs, I'd be ________ to buy one.	1	2	3	4
e. If PV systems had a proven safety record, I'd be ________ to buy one.	1	2	3	4

13. <u>Note that the scale changes for the next few statements</u>. Please circle the number on each of these scales that shows how much <u>less</u> likely you would be to purchase a PV system under the conditions of the statement.

	Almost certain not	Much less likely	A little less likely	No less likely
a. If a PV system would be unattractive on my house, I'd be ________ to buy one.	1	2	3	4
b. If PV manufacturers were small, unstable companies, I'd be ________ to buy one.	1	2	3	4
c. If a PV system needed lots of attention and maintenance, I'd be ________ to buy one.	1	2	3	4
d. If technological advances will eventually make currently available PV systems outdated, I'd be ________ to buy one.	1	2	3	4

14. If you were to purchase a photovoltaic system, how would you be most likely to pay for it?

Personal savings	_____
Included in mortgage	_____
Second mortgage	_____
Separate bank or credit union loan	_____
Other (please specify)	_____ ____________________

15. Do you intend to look for additional information about <u>any kind</u> of solar energy systems <u>within the next two or three months?</u>

Yes _____ No _____ (If "No", please skip to Q. 18)

16. About what kinds of solar energy systems will you look for information?

Solar water heating	_____
Solar-assisted heat pump	_____
Solar home heating	_____
Photovoltaic power systems	_____
Other (please specify)	_____ ____________________

17. Approximately how much does a gallon of unleaded, regular gasoline cost in your area?

$1.20 or less	_____	$1.35	_____
$1.25	_____	$1.40	_____
$1.30	_____	$1.45 or more	_____

18. How much do you think a gallon of unleaded, regular gasoline will cost five years from now (in 1985)?

$ ___________/gallon

19. Which of the following products have <u>you</u> bought for your own or your family's use?

Microwave oven	_____	Waterbed	_____
Home table-top computer	_____	Quartz room heater	_____
Videotape player/recorder	_____	Digital watch	_____
Food processor	_____	Whirlpool bath, spa or hot tub	_____

If you write to us at the return address, in several months, after the study is over we will send you a summary of the results.

Chapter 5

The Solar Heating and Cooling Residential Demonstration Program: Institutional Implications for Photovoltaics

Thomas E. Nutt-Powell

1.0 Introduction

In 1974 Congress passed and the President signed Public Law 93-409, the Solar Heating and Cooling Demonstration Act. This act represented a major public initiative to promote widespread solar energy utilization. A major goal of that program was acceptance of solar thermal technologies in the residential sector. As such, the solar thermal program offered an early case analysis of the federal role in solar implementation from which a number of lessons could be learned for the Photovoltaic Program.

This chapter summarizes the results of nearly three years of study of the institutional factors influencing solar acceptance in a variety of settings. In particular it presents a general structure of institutional analysis and an institutional analysis of the Solar Heating and Cooling Demonstration Program in the residential sector. The chapter presents a coherent picture of the program's design, implementation, and outcomes in order to promote an understanding of the implications of each for the design of programs to facilitate rapid acceptance of innovations such as photovoltaics in the residential sector.

2.0 The Analytic Approach

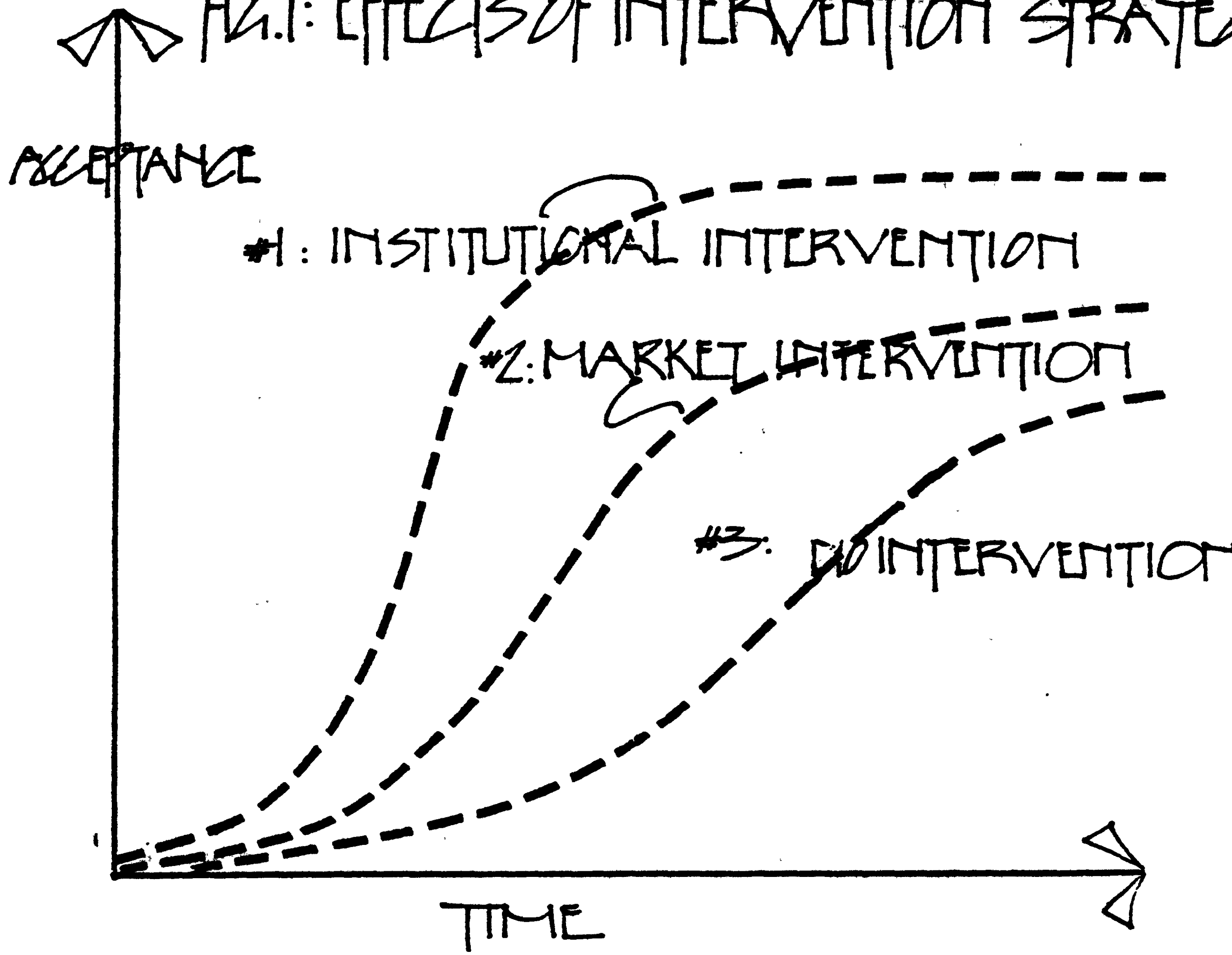
Institutional analysis assumes the existence of a variety of institutional entities and holds that the data on factors influencing innovation acceptance (and, by implication, resistance and/or rejections) lie in the exchanges between and among those entities (nature, rate, force, frequency, etc.). Such exchanges occur within institutional areas, which are described by the range and inclusiveness of the exchanges. Institutional analysis assumes that there are multiple currencies of exchange, each of which must be noted and is, to some extent, a factor in decision behavior. This is contrary to market analysis, which operates on the assumption that decision behavior can be adequately modeled in terms of willingness to make monetary exchanges. An understanding of the fuller range of institutional issues allows for a program design incorporating activities aimed at multiple exchange relationships. Such a program is more likely to be effective than market or any nonintervention approach.

Curve 1 in Figure 1 shows innovation acceptance without deliberate intervention. Curve 2 shows acceptance using a market intervention strategy. Basically, a market strategy moves the initiation of the acceptance curve ahead in time, but does not influence the rate or volume once it has begun. Curve 3 shows acceptance using an institutional intervention strategy. Acceptance activities begin sooner, at a more rapid rate, and with a higher final proportion of acceptance.

Table 1 describes housing as a sector characterized by multiple stages, actors, and constraints. Housing activity is very time- and place-specific, more so than other sectors, which have a relative uniformity of behavior regardless of time or location of activity. Therefore, while the stages, actors, and constraints shown on Table 1 represent the sector in general terms, specific manifestations of housing activity vary enormously from place to place and from time to time.

If "acceptance" means making something new a routine, then a measure of general acceptance of a solar technology in housing would be that it

FIG.1: EFFECTS OF INTERVENTION STRATEGIES



STAGES, ACTORS, CONSTRAINTS

IN THE HOUSING PRODUCTION PROCESS

	ACTORS	CONSTRAINTS
BUILDING CONCEPT *the generation of an idea*	DEVELOPER ARCHITECT ENGINEER PLANNER CONSULTANT	ZONING LAW USER NEEDS MARKET CONDITIONS
BUILDING DESIGN *establishing uses, design, specifications*	DEVELOPER LAWYER REAL ESTATE BROKER TITLE COMPANY ARCHITECT ENGINEER SURVEYOR PLANNER CONSULTANT ZONING & PLANNING OFFICIALS	REAL ESTATE LAW RECORDING REGULATIONS & FEES BANKING LAW ZONING LAW SUBDIVISION REGULATION PRIVATE DEED RESTRICTION PUBLIC MASTER PLANS
BUILDING FINANCE *price estimation and obtaining of funds*	LENDING INSTITUTIONS FHA/VA MORTGAGE COMPANIES INSURANCE COMPANIES INDIVIDUALS PENSION FUNDS REITS/MIT'S	BANKING LAW FHA/VA STATE LAW GNMA/FNMA
CONSTRUCTION *physical production*	DEVELOPER CONTRACTOR SUBCONTRACTOR TRADE UNIONS MATERIALS MANUFACTURERS & DISTRIBUTERS BUILDING CODE OFFICIALS INSURANCE COMPANIES ARCHITECTS ENGINEERS	RULES OF TRADE AND PROFESSIONAL ASSOCIATIONS BUILDING & MECHANICAL CODES SUBDIVISION REGULATIONS UTILITY REGULATIONS UNION RULES INSURANCE LAW MATERIALS TRANSPORT LAW
SERVICE AND OCCUPANCY *maintenance, management, repair, improvements, additions*	DEVELOPER LENDERS MORTGAGE COMPANY MAINTENANCE FIRMS PROPERTY MANAGEMENT FIRMS INSURANCE COMPANIES UTILITY COMPANIES TAX ASSESSORS REPAIRMEN UNIONS ARCHITECTS ENGINEERS CONTRACTORS SUBCONTRACTORS ZONING & BUILDING OFFICIALS MATERIALS SUPPLIERS REAL ESTATE BROKER	PROPERTY TAXES INCOME TAXES HOUSING & HEALTH CODES INSURANCE LAWS UTILITY REGULATIONS UNION RULES ZONING LAW BUILDING AND MECHANICAL CODES MATERIALS TRANSPORT LAWS BANKING LAW RULES OF TRADE & PROFESSIONAL ORGANIZATIONS
DISTRIBUTION *sale and subsequent resale and refinance*	DEVELOPER REAL ESTATE BROKER LAWYERS LENDERS TITLE COMPANIES FHA/VA/PRIVATE MORTGAGE/ INSURANCE COMPANIES BUYER	RECORDING REGULATIONS & FEES REAL ESTATE LAW TRANSFER TAKES BANKING LAW TAX LAW
TEAM SELECTION *a continuous creating of actors*	DEVELOPER ARCHITECT ENGINEERS CONTRACTORS FINANCERS	DEVELOPMENT REGULATIONS RULES OF TRADE AND PROFESSIONAL ORGANIZATIONS

SOURCE: Carole Swetky and Thomas E. Nutt-Powell, Institutional Analysis of Housing Production: A Preliminary Exploration (Cambridge, Mass.: MIT Energy Laboratory, 1979).

TABLE 1

appears in the notation of routine of each of the actors, from the four-year-old's rough crayon drawing of "my house" to the architect's elegantly presented grand scheme for a home or from the contractor's back-of-the-envelope notes for a materials order to the supply company's annual catalogue.

The goal of the institutional analysis of housing, in relation to the design of a program to facilitate an innovation's acceptance as routine, is to understand just what is considered routine in the residential sector.

3.0 The Solar Heating and Cooling Demonstration

3.1 Introduction

Before the early 1970s Congress paid little attention to solar energy. (The chronology in Appendix I presents key dates and events associated with the SHAC program.) In 1971 the House Committee on Science and Astronautics (S&A) organized a Task Force on Energy which operated parallel to an NSF/NASA Solar Energy Panel. Both organizations reported positively on solar potential by late 1972 and made favorable reference to the state of existing solar thermal technology and its adaptability to residential use.

S&A's Subcommittee on Energy conducted hearings on solar energy technologies in June, 1973. These led to support for expanded federal solar programs; and in October, 1973 the Subcommittee's chair, McCormick of Washington, submitted a techology-oriented solar bill. The bill provided key roles for several agencies including NASA, NSF, NBS, DOD, and HUD. In November Senator Cranston of California, whose primary committee was Banking, Housing, and Urban Affairs, submitted a housing-oriented solar bill.

The oil-embargo energy crisis of that winter prompted rapid consideration of the bills. An amended version of McCormick's bill passed the House in February 1974. The bill called for a demonstration of the potential for commercialization of solar energy from the point of view of technolgy development. It provided that NASA take a key role in guiding that development. In March the Senate Committee on Aeronautical and Space Sciences reported the House bill to the Senate. The new bill substituted similar technology development language from a companion Senate bill which had been introduced by Senators Moss and Weicker. The House bill was then referred to four Senate Committees: Commerce; Banking, Housing, and Urban Affairs; Labor and Public Welfare; and Interior and Insular Affairs. The multiple referrals reflected the bill's several policy dimensions as well as considerations of jurisdictional controls. Subcommittees of the first three Senate committees conducted hearings. By May the language for a Senate version, which emphasized the housing dimensions of the program, were agreed upon; on May 21 the bill passed the Senate. By the end of August, both houses had concurred wtih a Conference Committee report, and on September 3, 1974 President Ford ignored the bill.

In its final form the Solar Heating and Cooling Demonstration Act emphasized both technology development and use in the housing sector. Points that could not logically entertain both objectives were glossed over by appropriately vague language. NASA and HUD were both given key roles, and ERDA was named in anticipation of its imminent creation.

3.2 SHAC Program Design

From September through December, 1974 NASA and HUD collaborated with

NBS, DOD, and NSF to prepare the program plan required by the legislation. In January, 1975 ERDA was established. Two months later in March, the new agency issued ERDA 23, its national plan for the Solar Heating and Cooling Demonstration Program (Appendix II). SHAC identified a number of major activities--research and development; development in support of demonstrations; residential demonstrations; commercial demonstrations; data collection; and solar energy use in federal buildings--and a number of participants. HUD would take the lead in residential demonstrations; ERDA and NASA were assigned direct responsibility for most of the remaining tasks. Especially important was NASA's assignment for instrumentation, data collection, and analysis. The range of activities and the division of responsibilities reflect the effort to serve simultaneously two Congressional intents--technology development and housing.

3.3 SHAC-Residential Demonstration Program

The strategy that guided HUD's residential demonstration program design can be readily summarized by the following syllogism:

- o The developer/builder is motivated by the bottom line.
- o The bottom line is dollars.
- $o^{o}o$ Induce the developer/builder with dollars.

HUD used two types of demonstration approaches, site-system and integrated-system projects. Site-system projects involved matching a number of different systems designed for technology development purposes with a variety of climates and housing types. HUD decided upon this approach as a way to address the technology development goal. The choice meant, however, that HUD had to find developers willing to install NASA-prompted solar systems. Builders and developers did not readily accept the site-system approach, and HUD abandoned it after the first year of program operation.

The integrated-system approach had been discussed during hearings on both the House technology-oriented bill and the Senate housing-oriented bill. It was an approach with which HUD was familar, both through its ongoing housing programs and from its experience during Operation Breakthrough, an earlier effort at the develoment of industrialized housing. In the integrated-system projects, a builder-developer selected a currently marketed system and integrated it into an existing or proposed single- or multi-family housing project. Applcations for grant funds to cover the cost differential caused by the use of the solar system were accepted in a series of cycles initiated by nationwide solicitations. Through 1979 HUD had awarded over 750 grants totalling approximately $23 million for about 12,600 housing units.

HUD collected data on housing from projects using both approaches. HUD also provided certain of the projects with instrumentation to monitor technical performance. Though most of HUD's efforts were directed toward management of the demonstration approahes, it also incorporated provisions in the programs for developing performance criteria and standards and other, related studies.

A review of charts illustrating program organization and data flow provides interesting and revealing information (see Appendix II). Boeing, an organization with limited housing but considerable technological and engineering experience, was the major program contractor and is at the center of each chart. Organizationally Boeing was responsible for program management, data collection and analysis, and technical and grant management. Data, which are distinguished by their computer compatibility, flow to and through Boeing.

A look at the nature of the data collected (in grant applcations, progress reports, instrumented houses, and so on) reveals the extent to which this effort was driven by the technological orientation of the original bill, the emphasis of NASA/ERDA in this direction, and the inevitable mesh of Boeing's background with this orientation. Despite HUD's proclivities to put existing solar systems into housing and, thus, to develop a commercialization demonstration program in the residential sector, the instrumentation, data collection, and analysis orientation characterized the program as one of experimentation for technical development. The SHAC residential program, then, can be described in the following manner:

- The intent: a housing demonstration program illustrating the commerical feasibility of existing solar systems in various residential settings;
- The reality: a research and technology development program, pulled in that direction by the density of institutional forces (NASA/ERDA/Boeing/computer compatible data, for example) disposed to engineering experimentation;
- The outcome: a muddled program, serving the intended objectives neither clearly nor effectively.

The HUD SHAC residential demonstration program is muddled because it does not meet either the housing or the technology development objectives clearly or effectively. The program does meet some aspects of both objectives; and HUD, and its various contractors, approached and implemented their tasks responsibly. However, the very nature of the program's genesis and the constrasts resulting from the manner and crisis atmosphere in which Congress created the enabling legislation left a residue of early impossible conditions for implementing a program that was successful in achieving its objectives.

3.4 The Reasons for the SHAC Outcome

During a period of crisis, institutional entities fall back on routines which, by their very familiarity, provide confidence in the legitimacy of the activity about to be undertaken and the acceptability of its outcomes. In the winter of 1974, the Congress, NASA, HUD and the other primary institutional entities involved in the solar heating and cooling residential demonstrations program faced the oil embargo. A brief review of the arenas in which these institutional entities acted provides insights into the routines they adopted to create and implement the program. As shown in Table 2, the SHAC program involved four major institutional arenas--federal policy, program administration, technology development, and housing.

In Arena 1, Federal Policy, Congress is a major actor and money is the currency of exchange. Congress's major routine is to propose and enact enabling legislation, authorize activities to implement the legislation, and appropriate specific funds to pay for at least some of the authorized activities. Congress created the SHAC enabling legislation in an atmosphere of the national energy crisis. In response to this atmosphere Congress followed a typical routine, "throwing money at the problem." What is more, a Conference Committee, which was quickly called upon to resolve differences in language in legislation, used another typical routine. It combined language from both bills, despite inherent contradictions, and skillfully structured the language to obfuscate any differences.

Table 2

THE FOUR INSTITUTIONAL AREAS IN THE SHAC PROGRAM

ARENA 1

Institutional Arena: Federal Policy

Currency of Exchange: Money

Atmosphere: National Energy Crisis

Routine: Propose, Enact, Authorize, Appropriate

ARENA 2

Institutional Arena: Federal Proram Administration

Currency of Exchange: Status

Atmosphere: Turf Protection

Routine: Obtaining and Running Programs

ARENA 3

Institutional Arena: Technology Development

Currency of Exchange: Quantifiable Data

Atmosphere: Engineering Crisis

Routine: Instrument

ARENA 4

Institutional Arena: Housing

Currency of Exchange: Marketability

Atmosphere: Market Risk, Mitigated by Interdependencies

Routine: Word of Mouth

In Arena 2, Federal Program Administration, the currency of exchange is status and federal agencies are primary actors. The routine in this area is to obtain and run programs with the purpose of achieving status. Each program yields a different level of status. The atmosphere in which the routine is carried out is turf protection--keeping programs, especially those that yield a high level of status, and working to acquire additional programs. Status in this context is not equated with level of funding although in some cases funding may have some influence on it. Rather status represents the perceptions of importance among the particular institutional entities in the area. In the case of SHAC, HUD clearly stood to gain some status if it ran the residential component, and even more status if the language of the enabling statutes were consistent with the definitions of HUD turf. Conversely, HUD would lose status if neither of those situations obtained.

In Arena 3, Technology Development, the currency of exchange is quantifiable data. The routine adopted to trade in this currency is instrumentation. In the case of the SHAC program NASA and ERDA perceived that existing solar thermal hardware was underdeveloped enough to generate an engineering crisis. At the very least the stage of development did not meet the claims made during the Congressional hearings. Reacting to the atmosphere of crisis surrounding the legislation, NASA and ERDA pushed for a technology development effort even greater than envisioned by the original technology-oriented House bill. The heavy emphasis on computer compatible data, even in the housing demonstrations, is evidence of the forcefulness of this effort.

In Arena 4, Housing, the currency of exchange is marketability. As mentioned in the opening section of this chapter, the housing area is highly disaggregated and very responsive to conditions in the local markets. Activities in the housing arena take place in an atmosphere of market risk; that risk is mitigated by the interdependencies of all the actors in the market. The routine in the housing arena through which these entities interact is word of mouth.

Even this brief review of the four institutional arenas most involved in the HUD SHAC residential demonstration program reveals clear mismatches in the currencies of exchange, routines, and atmospheres. Concluding that institutional entities from these four arenas could readily mesh activities to accelerate the acceptance of solar technologies is as difficult as imagining that a business manager of a Teamster's local, a debutante, and medical technician, and a neighborhood gossip could form easy and pleasant company for each other at a dinner party given by the head of the Latvian Communist party.

4.0 Factors in the Acceptance of Solar Energy in Housing

4.1 Introduction

In the course of analysis, three general types of factor prompting builder/developers to integrate solar thermal technologies into housing emerged. These are useful in understanding housing institutional arena routine and especially important for designing programs that can connect innovation to routine in order to facilitate innovation acceptance. The three factor types are developer motivation, information exchanges, and comprehensibiity.

A series of case studies illuminated the character of the three factors:

Friends Community: a 160-unit, semi-detached housing development in North Easton, Mass., developed by a nonprofit corporation established by the New England Yearly Meeting;

Reservoir-Hill Solar Houses: a 15-unit, single-family, attached market-rate development in the the Reservoir Hill urban renewal area of Baltimore, MD.;

Project Solar for Indiana: single-family houses, identical in terms of design, size, and solar units, each constructed by one of seven builders in different parts of the state with the coordinating sponsorship of the Homebuilders Association of Indiana;

Santa Clara, California: a city-owned utility installing solar units in a new single-family development on the same basis as electric service;

San Diego County, California: a mandatory solar hot water ordinance adopted by a county for new housing development;

PNM/AMREP: the collaboration of a major utility (Public Services of New Mexico) and a major developer (AMREP) in the development of 25 solar homes in New Mexico, 23 of which are in AMREP's Rio Ranco Development in the Albuquerque housing market.

The prevailing notion had been that money stimulates builder/developer behavior. The case studies revealed the existence of other influences. Each of these was a necessary impetus for even contemplating the purchase of a solar thermal system.

4.2 Developer Motivations

In Friends Community, selecting a solar system was a logical consequence of the ideals on which the development was based and was pursued despite the persistent arguments of infeasibility offered by many of the project's advisers. Normatively motivated developers commonly base decisions on their ideals. In Indiana team spirit motivated each of the seven developers involved in the Solar for Indiana project. None of them had responsed to HUD's early proposal solicitations. However, each was very active in HBAI, and became involved in Cycle 3 as a consequence. The developer of Reservoir Hills in Maryland used solar as the lever to make his new development corporation viable. The solar grant provided the organizational foundation for his venture. AMREP was interested in solar as a potential vehicle for corporate expansion long before the HUD program. AMREP's idea that anything with a "sunny" character, fitting the New Mexico climate, could potentially enhance the corporation's image and consequent market share, not through an actual technical performance, but precisely because of its "sunny-ness".

4.3 Information Exchanges

The type, source density, and continuity of information exchange influenced builder/developers' acceptance of solar technologies in housing. The critical information for the Reservoir Hills builder was not that solar would work but that it would make the development financially feasible in the eyes of the financial backer. The types of information (financial) and the source (a savings and loan association) were very important factors. Information of another type (aesthetic appeal, for example) or from another source (e.g., information of financial feasibility from the city's design review committee) would not have been as compelling to that developer.

The compelling factor for the builder in Indiana was that the project information came from a highly trusted source, the Homebuilders Association of Indiana. The same information had been made available in preceding years thorough HUD's solicitation process with additional prompting from the state's Energy Office; but it had not been viewed positively, notably because each of those sources was outside the routine of Indiana builders.

The density of information was an important variable for AMREP. The company had been considering a solar initiative for its Rio Rancho development for over a year. AMREP decided to act after its Director of

Construction had participated in a two-day MITRE Corporation conference devoted entirely to solar energy. The density of information provided by this conference was the impetus for AMREP to commit its resources to designing a prototype solar unit and testing it at Rio Rancho before the SHAC program had even been approved by Congress.

In Santa Clara, California, a Science Adviser, funded by NSF as part of its initial grant to use solar enery in a new municipal recreation facility, provided the continuity of interest in solar. The Science Adviser become a continuing source of information. He was utlimately responsible for furnishing new ideas on possible solar applications, including the installation by the municipally owned utility of solar home heating and hot water units in new homes as part of the HUD program.

4.4 Comprehensibility

The more comprehensible an innovation, the more readily it will be accepted. In the context of this study comprehensibility means that the actors can understand an innovation because it is part of and/or relates to the routines that exist. Information provided by the supporting institutional network enhances this comprehensibility. In the housing area, this process becomes part of the basic routine as one of the interdependencies created to mitigate market risk for any of the institutional entities in the arena.

In the Indiana program, a legitimator, the Homebuilders Association of Indiana, enhanced comprehensibility. In the AMREP/PNM program, a translator, the vice-president of the solar system supplier, enhanced comprehensibility. The person was able to interpret the needs and interests of the two parties for each other and, in turn, to create an acceptable solution in solar terms, solar being a new "language" for both

AMREP and PNM. AMREP's early interest in solar energy was generated by the presence of a linking pin, an environmental consultant, who also consults with MITRE and General Electric in developing their solar energy interest, linked AMREP to these two companies and provided the critical first step in AMREP's acceptance of the solar innovation as part of its corporate routine.

The New England Yearly Meeting, which developed Friends Community in Masschusetts, is a classic example of a different sort of actor--the plunger, an institutional entity that accepts an innovation mostly as an article of belief, and plunges ahead with its implementation against all odds and logic. For the Friends, technical infeasibility could not outweigh the routine feasibility of their beliefs.

Finally, San Diego County's role as a regulator, requiring by county ordinance solar in new development was simply a continuing manifestation of the county's routine activities in relation to builder/developers. The county did not need to expend funds on direct financial incentives; rather it constrained the options of builders and gave them no choice but to accept solar.

5.0 Meshing Innovation with Routine

The SHAC program is a legislative hybrid of technology development and housing objectives limited by its hybrid origin to, at best, partial achievement of its goals. As suggested in the comparison of the four institutional arenas, their currencies of exchange and routines do not mesh. When the routines of any given arena are met, those of one or more of the other routines are thrown into confusion.

In housing, financial incentives and technical data are not sufficient to lead to the acceptance of a solar innovation. The former represent the currency of the federal policy arena, the latter the currency of the technology development arena. Neither contributes to the currency of the housing arena, marketability, which is passed by word of mouth. Marketability is influenced by developer motivation, information exchange (type, source, density, continuity), and the comprehensibility provided by matching the routines of the particular arena, especially through such mediating institutional forces as a legitimator, translator, linking pin, plunger, and or regulator.

Innovation acceptance in the housing arena requires mediation through routine at the local market level. The nature of mediationn, which aids comprehensibility, can be analyzed in a general sense (as above) but cannot be planned for in the aggregate. An analysis of each housing arena is necessary to understand the nature of the mediating routines and entities that it contains.

Recipients of SHAC subsidies were motivated by other than conventional market objectives. The motivations that prompted developer involvement in the SHAC residential demonstration program were varied but cannot be characterized as market-oriented. The motivations included realization of ideals (Friends), team spirit (Indiana), organizational foundation (Reservoir Hills), and corporate expansion (AMREP).

Acceptance of the subsidy does not necessarily mean acceptance of the innovation. No developer refused the subsidy (although AMREP's first prototype was done entirely with corporate funds); however, accepting the subsidy was not a sign that a developer had accepted the innovation. The subsidy more typically allowed the realization of other objectives. Because the realization of the solar energy innovationn accompanied the realization of other objectives, solar may find general acceptance comes easier later on. Being cloaked in the mantle of the success of other objectives contributes to furthering innovation acceptance. However, such simultaneity of events could just as likely be an example of spurious correlation as it is evidence of geniune acceptance.

The probability of acceptance of an innovation increases when information comes through routine exchanges. Especially in an arena such as housing, which exists in an atmosphere of market risk, the extent to which routines mediates the entry of an innovation is a measure of the probability of its acceptance. HBAI acting as a legitimator, the solar supplier acting as a translator, the environmental consultant as a linking pin, and the county as a regulatory are all examples of routines in housing arenas which mitigate market risk by fostering particular institutional interdependencies.

Information must pertain to the innovation, not to the subsidy. Institutional entities typically assume that federal programs only provide funds. In this case they saw the SHAC residential demonstration program as a means to obtain funds and, as a consequence, established no new routines. The developers who continue to maintain a commitment to solar energy (Friends, Santa Clara, AMREP) were already committed to solar energy before they participated in SHAC; HUD funds simply made it easier for them to realize other motivations that were linked with, but not dependent upon, solar. Developers who have not continued to use solar energy (Reservoir Hills, Indiana) would again accept federal grants, for solar or any other activity that served their own objectives.

6.0 Lessons

There are at least three very basic lessons to be learned from the SHAC residential demonstration program relative to designing a program to facilitate rapid acceptance of photovoltaics in the residential sector.

Research and demonstration are separate activities. Research and related development activities tend to fall into the technology development arena. Demonstration tends to fall into the federal program administration arena. The currencies of exchange and routines of each do not mesh. In constructing the SHAC legislation Congress mixed the two, creating a hybrid program doomed to frustrate the hopes of persons interested in achieving either set of objectives. Program design, implementation, and evaluation for the two are different. To be successful, each objective must be provided for separately.

The design and administration of innovation acceptance programs for the housing arena should take place outside Washington, D.C. The federal policy and program administration institutional arenas are among the few that exhibit a unity of conceptual and geopolitical space. The density of information exchanges this occasions, the legitimacy this density creates, and the consequent primacy of routines from these two institutional arenas create a strong climate of confidence in the routines. Because innovation acceptance in housing is facilitated by programming to match existing and definitionally local housing arena routines, design and administration of such a program must be allowed to escape capture by routines that counter chances of achieving success in the housing arena.

An effective program to facilitate innovation acceptance must mesh with the routines of the accepting institutional arena. Because in housing the routing is word of mouth, with exchanges among and between multiple actors with multiple motivations and maximum interdependencies, the key to an effective program is a strategy that allows the disseminationn of information in each local housing market.

APPENDIX I

SHAC CHRONOLOGY

Sources

1951-72	Diverse bills filed; none passed.
1952	Paley Report on materials policy need for solar energy research.
1971-72	Task Force on Energy, House committee on Science & Astronautics (S&A).
Dec., 1972	NSF/NASA Solar Energy Panel Report.
1972	S&A Committee Staff Report.

Design

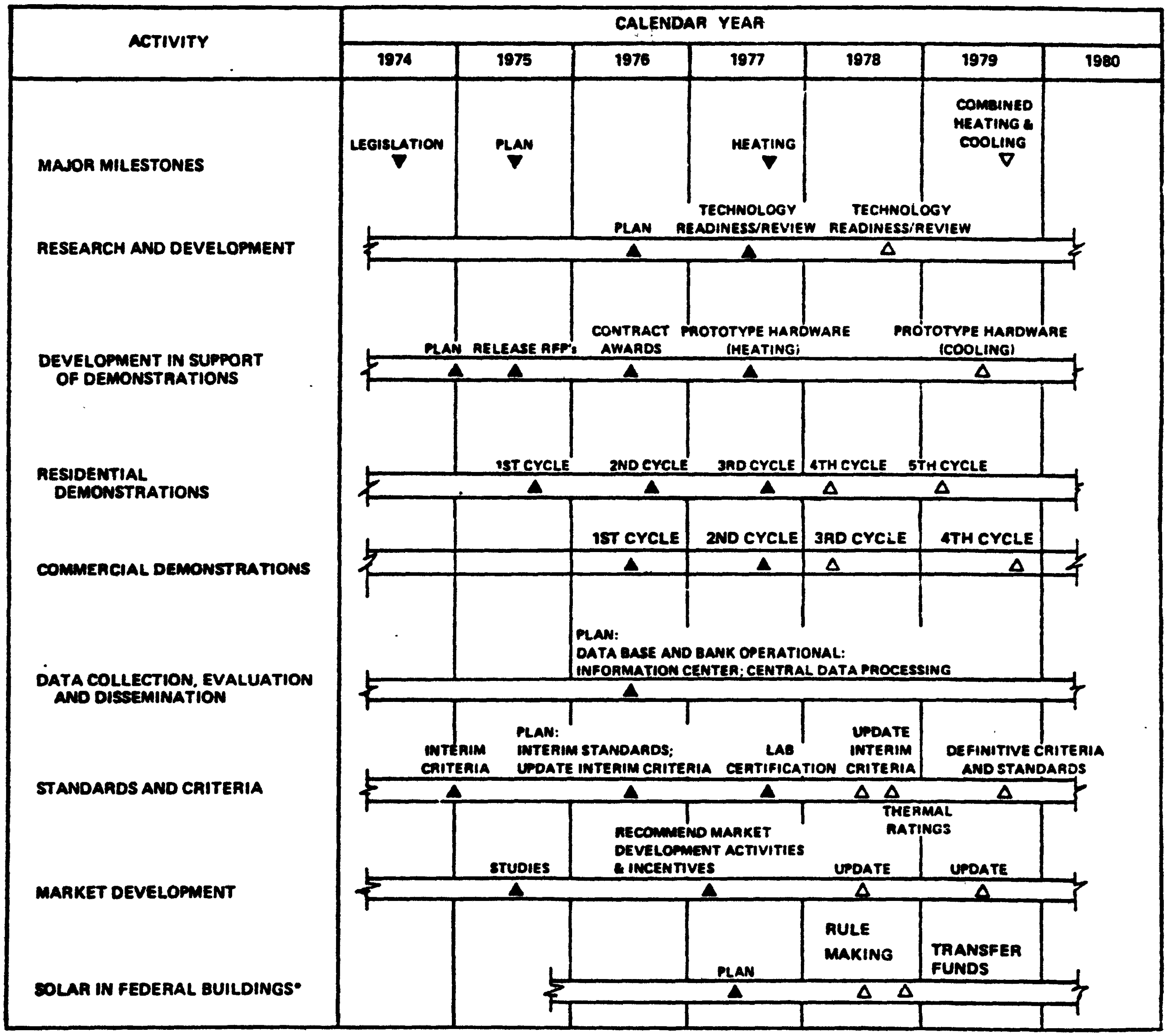
June 7, 12, 1973	Hearings on solar energy technologies; S&A Subcommittee on Energy supported, expanded; federal solar programs.
June-Oct. 1973	HR 10952 drafted; NSF, NBS, NASA, HUD, DOD introduced 10116 by McCormick.
Nov. 2, 1973	S.2650 introduced by Cranston (Banking, Housing and Urban Affairs).
Nov. 5, 1973	S.2658 (H11864 companion) introduced by Mos & Weicker.
Nov. 13-15, 1973	Hearings on HR 10952 Energy Subcommittee.
Dec. 10, 1973	HR11864 (amended version of 10952) to full committee.
Jan. 28, 1974	Reported to House.
Feb. 13, 1974	Passed, with amendments by House.
Feb. 19, 1974	HR11864 referred to Senate Committee on Aeronautical & Space Sciences.
Feb. 25, 1974	Senate hearings on HR11864, S. 2658.
March 11, 1974	Senate Committee (A.S.S.) reports HR11864 substituting S.2658 language.
March 13, 1974	HR11864/S.2658 referred to 4 Senate Committees: Commerce; Banking, Housing, & Urban Affairs; Labor & Public Welfare; Interior & Insular Affairs.

March 20-21, 1974	Hearings on S.2650 & HR11864, BHUA Subcommittee on H & VA.
March 27, 1974	Hearings on S.2650 and HR11864, L&W Subcommittee on NSF.
March 29 and April 5, 1974	Hearings on S.2650 and HR11864 - Subcommittee on Science and Technology.
May 21 , 1974	HR11864 passes Senate, with amendments.
Aug. 12, 1974	Conference Report, Senate agrees
Aug. 21, 1974	House agrees.
Sept. 3, 1974	President Ford signs PL 93-409.

<u>Implementation</u>

Sept.-Dec., 1974	NASA/HUD with NBS, DOD, NSF prepare program plan submitted to Congress 12/30/74.
Sept.-Dec., 1974	HUD prepares interim performance criteria for systems and dwellings to White House/Congress 1/1/75
Jan. 19, 1975	ERDA established--PL 93-438.
March 1975	ERDA 23--National plan.
Oct. 1975	1st National Conference on Solar Standards.
Sept. 13-15, 1975	2nd National Conference on Solar Standards.
Jan. 19, 1976	HUD Cycle 1.
Nov. 1976	ERDA 23A--(76-6) updated national plan.
Jan. 1, 1977	HUD Cycle 2.
May 30, 1977	HUD Cycle 3.
Oct. 1977	DOE established.
Mar. 29, 1978	HUD Cycle 4.
July 1978	DOE/CS-0007 national plan.
Sept. 28, 1978	HUD Cycle 4a--passive.

SOLAR HEATING AND COOLING PROGRAM



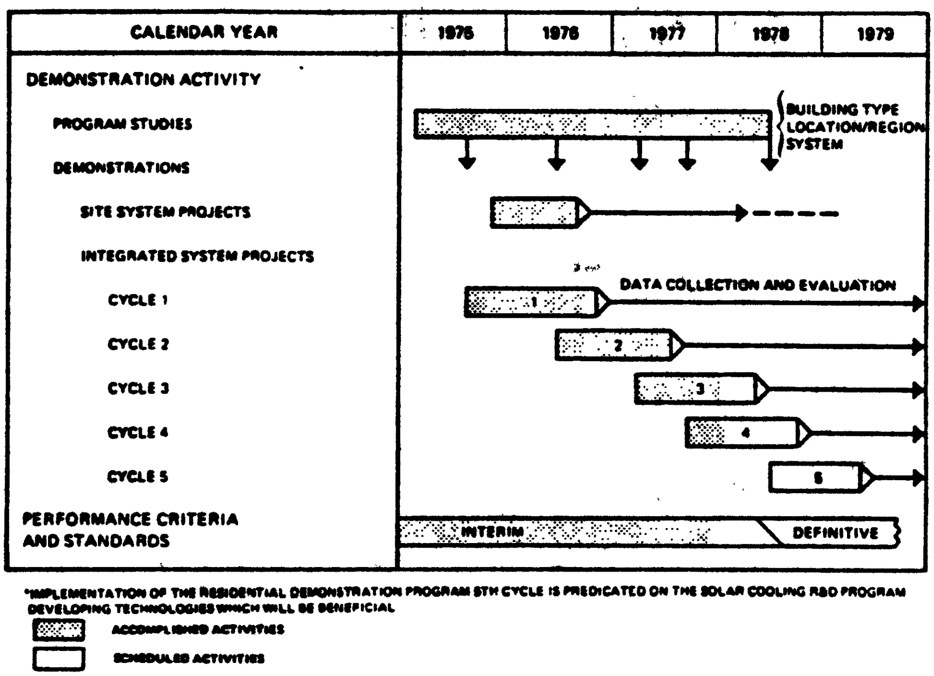
*A NEW THREE YEAR PROGRAM TO BE DEVELOPED IN ACCORDANCE WITH THE NEP.

▲ ACCOMPLISHED ACTIVITIES

△ SCHEDULED ACTIVITIES

SOURCE: DOE, 1978c.

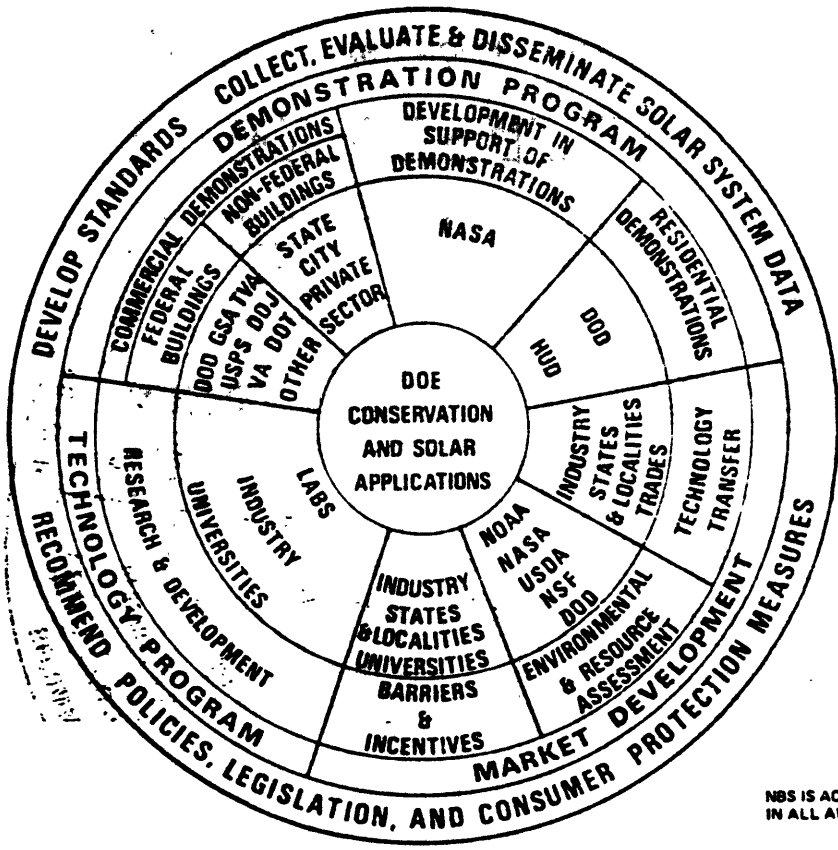
HUD RESIDENTIAL DEMONSTRATION PROGRAM



*IMPLEMENTATION OF THE RESIDENTIAL DEMONSTRATION PROGRAM 5TH CYCLE IS PREDICATED ON THE SOLAR COOLING R&D PROGRAM DEVELOPING TECHNOLOGIES WHICH WILL BE BENEFICIAL

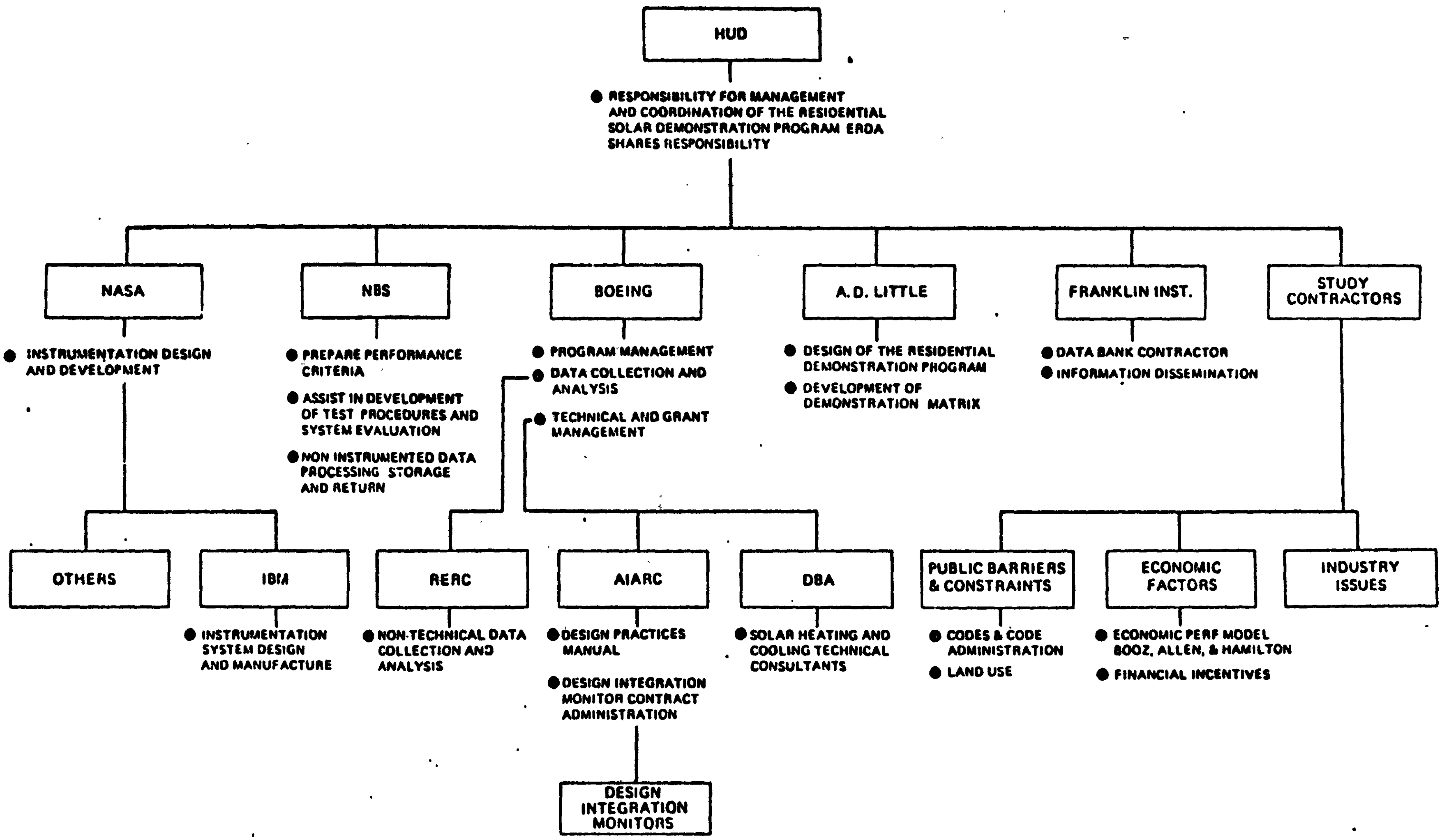
SOURCE: DOE, 1978c.

PROGRAM PARTICIPATION
NATIONAL HEATING AND COOLING OF BUILDINGS



NBS IS ACTIVE IN ALL AREAS

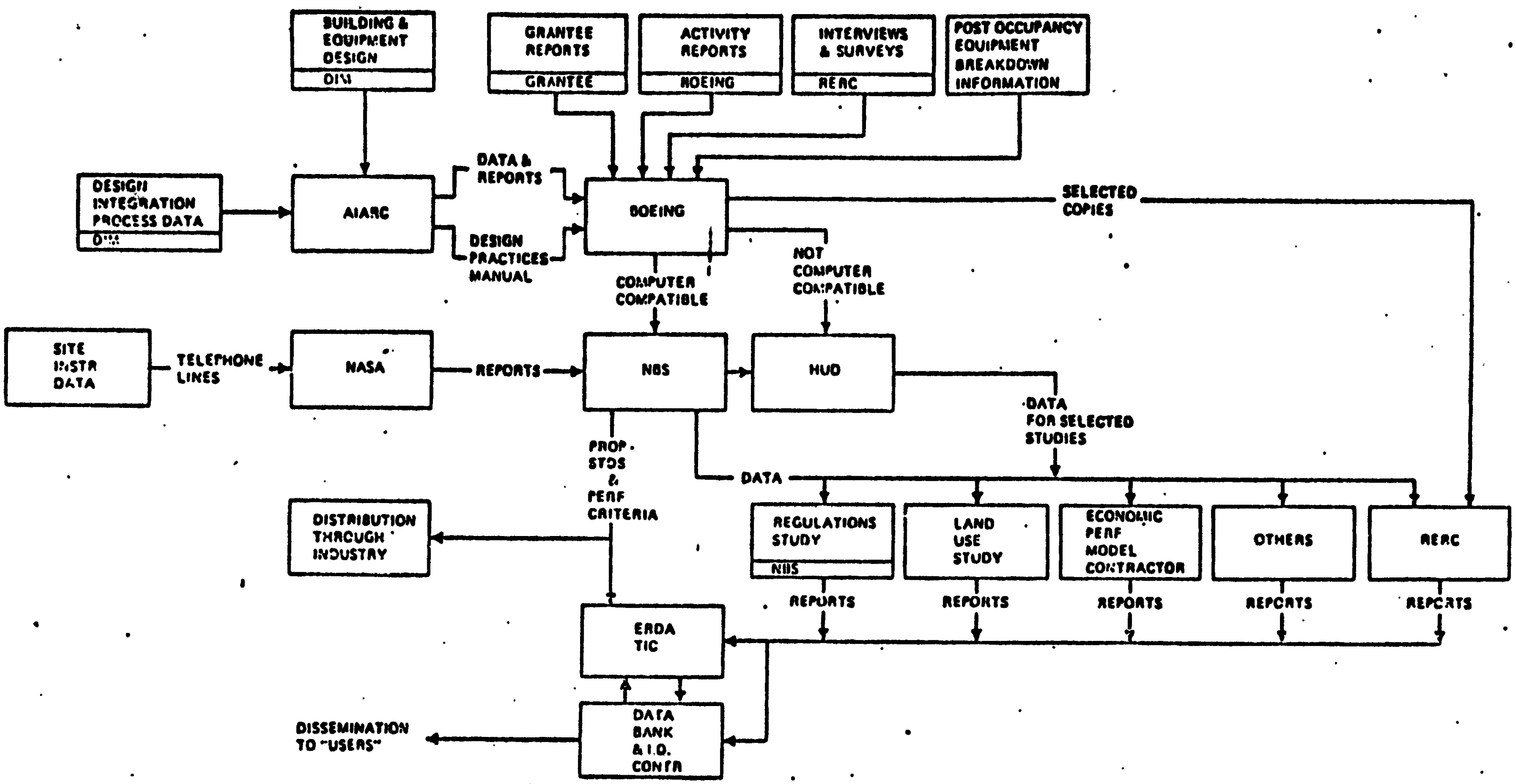
SOURCE: DOE, 1978c.



HUD Solar Energy Demonstration Program Organization Chart

RESIDENTIAL DEMONSTRATION PROGRAM

DATA FLOW CHART



REFERENCES

DOE (1978a) Solar Heating and Cooling Demonstration Project Summaries
Washington: DOE/CS-0009.

DOE (1978b) Solar Heating and Cooling Research and Development Project Summaries
Washington: DOE/CS-0010.

DOE (1978c) National Program for Solar Heating and Cooling of Buildings: Annual Report
Washington: DOE/CS-0007.

ERDA (1976) National Program for Solar Heating and Cooling of Buildings: Project Data Summaries, Volume 1, Commercial and Residential Demonstrations
Washington: Division of Solar Energy.

Furlong, Michael and Nutt-Powell, Thomas E. (1979) Institutional Analysis of Research and Socialization in Housing: A Preliminary Exploration
Cambridge: MIT Energy Laboratory

HUD (1976) Solar Heating and Cooling Demonstration Program: A Descriptive Summary of HUD Cycle Solar Residential Projects
Washington: HUD-PDR-230.

HUD (1977) Solar Heating and Cooling Demonstration Projects: A Descriptive Summary of HUD Cycle 3 Solar Residential Projects
Washington: HUD-PDR-230-1.

HUD (1978) Residential Energy from the Sun: A Brief Description of HUD's Residential Solar Demonstration Program
Washington: HUD-PDR-351.

Library of Congress, Congressional Research Service, Science Policy Research Division, Energy Research and Development Administration, Statutes and Legislative Histories: Volume I, Solar Heating and Cooling Demonstrationn Act of 1974, prepared for the Subcommittee on Advanced Energy Technologies and Energy Conservation Research, Development and Demonstration of the Committee on Science and Technology, U.S. House of Representatives (Washington, Government Printing Office, April 1978).

McDaniel, Patricia and Nutt-Powell, Thomas E. (1979) Institutional Analysis of Governmental Involvement in Housing: A Preliminary Exploration
Cambridge, MIT Energy Laboratory

Nutt-Powell, Thomas E. with Landers, Stewart, Nutt-Powell, Bonnie R. and Sorrell, Levi (1978) Toward a Theory of Institutional Analysis
Cambridge, MIT Energy Laboratory

Nutt-Powell, Thomas E., Furlong, Michael, McDaniel, Particia, Parker, Barbara and Reamer, Andrew (1979) Solar Heating and Cooling of Housing: Five Institutional Analysis Case Studies
Cambridge, MIT Energy Laboratory

Parker, Barbara and Nutt-Powell, Thomas E. (1979) Institutional Analysis of Standard Setting in the United States: A Preliminary Exploration
Cambridge, MIT Energy Laboratory

Reamer, Andrew, Heim, Steven and Nutt-Powell, Thomas E. (1979) Institutional Analysis of Energy Provision in Housing: A Preliminary Analysis
Cambridge, MIT Energy Laboratory

Swetky, Carole and Nutt-Powell, Thomas E. (1979) Institutional Analysis of Housing Production: A Preliminary Exploration
Cambridge, MIT Energy Laboratory

Chapter 6

Summary of State Activities Under PURPA Section 210

Drew J. Bottaro

1.0 Introduction

1.1 Brief History of PURPA Regulation

In November, 1978, the Public Utility Regulatory Policies Act of 1978 (PURPA)[1], one of the five national energy acts, became law. Among its provisions were two sections which obligated utilities to purchase power from and sell auxiliary power to qualifying cogeneration and small power production facilities (such as photovoltaic systems).[2] These sections also required state public utility commissions to establish rates for these purchases and sales which were just, reasonable, and in the public interest, and which did not exceed the incremental costs the utility faced for producing additional electric power.

The Federal Energy Regulatory Commission (FERC) was mandated to establish rules for calculating the rates and for determining which facilities qualified for PURPA's benefits.[3] Pursuant to this statutory mandate, FERC promulgated rules.[4] These rules required that the state

---

[1]P.L. 95-617 (November 9, 1978); 92 Stat. 3117. The constitutionality of PURPA has recently been argued before the Supreme Court on appeal from a decision of the U.S. District Court for the Southern District of Mississippi in Mississippi v. FERC (February 19, 1981).

[2]Sections 201 and 210.

[3]Section 210(a).

[4]18 C.F.R. sections 292.101, .301-.602 (1980). The validity of these rules has been cast into doubt by the U.S. Court of Appeals (D.C. Circuit) in AEP v. FERC (January 22, 1982) which invalidated the FERC rules regarding the requirement that rates must equal avoided costs and the requirement that utilities must interconnect with qualified facilities. The matter is currently under appeal, and this study treats the rule as valid until a final determination is made in the case.

public utility commissions establish rates based upon the costs which the utility would avoid due to power purchased from qualifying facilities (QFs). The states were given latitude in deriving methodologies for calculating avoided costs so long as the rates were not less than incremental costs.

The states were also to establish any other conditions which QFs would have to meet before the utility would be required to purchase power from the QF. These conditions usually concerned the interconnection of the QF to the utility grid.

Formal action by the states was required to be initiated by March 20, 1981, one year after the effective date of the FERC regulations.

1.2 Policy Implications for Photovoltaics

The actions of the state public utility commissions are important because they affect the rates which photovoltaic power producers (and other QFs) receive for the power they sell and which they pay for power they purchase, two key determinants of the break-even cost[5] of photovoltaic systems. They also determine the conditions which photovoltaic power producers must meet in order to interconnect with utilities, conditions which will affect the balance-of-system costs and therefore also affect photovoltaic system break-even.

This study examines the actions of the state public utility commissions under PURPA in order to identify issues concerning the development and diffusion of photovoltaic systems which their actions raise. The study approaches the problem not by examining *per se* the

---

[5]Calculation of break-even cost is discussed in "An Economic Analysis of Grid-Connected Residential Solar Photovoltaic Power Systems" by Paul Carpenter and Gerald Taylor, MIT Energy Laboratory Report MIT-EL 78-007 (Revised December 1978).

rates and charges established by the commissions, as those will change over time, but rather by examining the methodologies and reasoning used to arrive at the rates and charges. Obviously, the higher the rates paid to photovoltaic power producers for their power and the lower the costs they pay for auxiliary power, the better will be system break-even cost, all else being equal. The more important issue from the policy perspective, however, is whether any general trends in the implementation of PURPA raise concerns which could be addressed more effectively by DoE than by individual photovoltaic power producers challenging specific rates or conditions.

Entities in addition to the public utility commissions are also required to act under PURPA. These entities include federal and state power generation entities (such as TVA) and nonregulated utilities. While their actions are also important, they have not been studied here for two reasons. First, their omission simplifies the scope of the efforts taken, allowing the study's focus to be upon a much smaller number of entities, namely the state public utility commissions. Second, the public utility commissions should be best able, as a group, to analyze the issues. Any concerns present with regard to the behavior of the public utility commissions are likely to be more serious for the other self-regulated entities, and studying the public utility commissions should help produce a clearer understanding of the issues.

The study proceeded as follows. Records of proceedings under PURPA concerning rates for QFs were collected for each of the fifty states plus the District of Columbia. These records are summarized by state and by issue in a separate Appendix, MIT Energy Laboratory Working Paper MIT-EL 82-017WP; the summaries are the basis for the charts presented in this report. Most records are up to date through valiant efforts to remain current on each state's proceedings. Often we became formal observers to the proceedings in order to be placed upon official mailing lists, and hence we believe that most of our summaries are current as of August 31, 1981. Some are current through December 31, 1981. However, in some states our records may not be accurate as of August 31, as further action may have been taken since our last communication with the public utility commission. In some states we are relying upon staff reports or proposed rules, as those are the most current actions of the public utility commission. That some records are not final nor necessarily up-to-date should not detract from our analysis of the behavior of the public utility commissions overall.

The individual state summaries were analyzed to determine the actions of the state's public utility commission concerning several issues of potential significance for the economics of photovoltaic systems. These issues cover the status of the commission's proceedings, the regulatory role of existing and subsequent contracts between utilities and QFs, the way in which the rate-setting methodologies were established, what the methodologies are, what interconnection requirements were established, what arrangements for wheeling were made, and what actions were taken regarding rates for supplying auxiliary power to QFs. Some of these issues were analyzed because of their immediate significance for photovoltaic systems economics, such as the nature of the rate-setting methodologies established. Others, such as the regulatory role of contracts, were studied because they may help in subsequent analysis of any future sluggishness in the regulatory process which may impede the introduction of photovoltaic systems.

The actions of all the states on all the issues were then further summarized. This report represents the final synthesis of all the information concerning the states' actions. Each issue of potential significance is discussed following this introduction, and the actions of the public utility commissions are summarized in chart form. The charts presented in this report aggregate the action of the public utility commissions; no information on the actions of individual states is presented. Charts which present the actions of all the states on each of the issues may be found in the separate Appendix referenced above; the summaries of each individual state's actions may also be found in that document.

Following the issue-by-issue analysis is a concluding section which highlights the most important issues affecting the economics of photovoltaic systems.

2.0 Summary of State Actions on Specific Issues

This section presents a summary of the actions of the fifty states and the District of Columbia on each of the seven issues listed in the introduction: the status of the state commission's proceedings, the regulatory role of existing and subsequent contracts between utilities and QFs, the manner in which the rate-setting methodologies were established, what the methodologies are, what interconnection requirements were established, what arrangements for wheeling were made, and what actions were taken regarding rates for supplying auxiliary power to QFs. Each issue will be discussed in a separate section below.

2.1 Status of Proceedings

Under the FERC rules, all state public utility commissions were supposed to comply with PURPA's requirements for QFs by March 20, 1981. While most public utility commissions had at least begun action by that date, only eight were completed. As of the end of 1981, however, over half the commissions have taken final action, and the rest have proceedings under way.

Table I presents these results. It presents a minimum level of compliance; by now more public utility commissions may have completed action. As rate-setting usually follows final action, it may take some additional time before all utilities have rates appproved by their commissions. Substantial progress has been made, however.

Table I

STATUS OF COMMISSION ACTION UNDER SECTION 210

Commissions having taken final action:		28
By March 20, 1981	8	
Since March 20, 1981	20	
Commissions with action under way		23

As the table shows, 23 states have not completed action, according to our records. For 11 of these, we do not have an adequate basis to characterize the commission's behavior; these 11 will be included in subsequent tables under the "no information" headings. However, all commissions have initiated proceedings, according to our records; many of these 23 may have completed action as of the publication date of this report.

As a result of this broad level of compliance, concerns that either slowness or inaction of state public utility commissions would retard the introduction of photovoltaic systems have become largely moot.

2.2 Contracts

The ability of a photovoltaic power producer to negotiate a fair contract with a utility is important to the economics of photovoltaic systems. While it is too early to tell what the consequences of different forms of contract regulation will be, the information is noted here for future reference. Table II presents the summary information on commission practices.

Table II

COMMISSION POLICIES ON CONTRACTS INVOLVING QFS

	No. of commissions
Contracts required:	
Yes, all QFs	23
Yes, QFs above a threshold size	4
No requirement of a contract	6
No information/not specified/unclear	18
Standard tariff available:	
All QFs	7
Small QFs only	16
None	34
PUC oversight of contracts:	
Active	6
Reactive	11
None/not specified/no information	34

Most public utility commissions require utilities and QFs to enter into contracts. Whether or not they require such contracts, many require that utilities establish standard tariffs for power purchased from QFs which the QFs may use in lieu of a negotiated contract. Whether or not the public utility commission requires a contract for power purchases, it may require a contract stating QF (and utility) obligations regarding interconnection requirements. Hence the public utility commissions retain some control over the transactions between the utilities and the QFs. To the extent that the rates and conditions which the commissions establish are reasonable (see sections C through E below), the QFs should be able to benefit from a much-improved bargaining position due to the legal presence of the public utility commission.

A number of public utility commissions also require either active commission review of all contracts or allow review upon motion by either the QF or the utility. Very likely many of the 34 commissions which did not indicate the possibility of review may have generally applicable procedures which were simply not mentioned in the QF rate-making proceedings; thus commission involvement is no less than indicated in Table II. Again, the position of the QF should be enhanced by this opportunity for commission intervention as the commission should help to neutralize any bargaining advantage the utility may have.

There is a concern, however, that too much involvement of regulators may become unduly burdensome upon QFs, with the result being that QFs and utilities will negotiate contracts outside the regulatory protections of PURPA (something specifically allowed in the FERC rules), thus diminishing the value of those protections. There is some evidence by word-of-mouth that QFs which have negotiated with utilities to date have opted for long-term contracts at rates below regulated rates in order to get the long-term commitments necessary to obtain bank financing. The significance of this possibility cannot be evaluated as yet due to lack of evidence of specific negotiated rates and contract terms.

2.3 Establishment of Methodology

The manner in which the state public utility commissions establish their methodologies for purchasing power from QFs, while not directly affecting the economics of photovoltaic systems, is nevertheless important for two reasons. First, it may be indicative of the commission's efficacy in implementing PURPA. A commission which, due to staff shortages or other reasons, must rely upon methodologies developed by the utilities may not be able to oversee interactions between utilities and QFs very effectively. Second, the commission's manner of establishing the methodologies may make any federal oversight difficult, thus reducing the potential benefits from federal presence in the area. While these concerns do not necessarily result in regulatory difficulties, they have been studied because they may indicate the need for policy action at a later date. Their importance is supported by the requirement in the PURPA statute that the state public utility commissions adopt rules after notice and hearing[6], indicating that the commissions' actions are intended to be reasoned and reviewable.

Most commissions for which we have information relied upon utility filings of "avoided cost" rates to satisfy their requirement to establish a methodology. Very little guidance was given to the utilities other than repeating the list of factors which FERC suggested the commissions consider; the filings were merely subject to ad hoc commission review. Some commissions did give additional guidance, but stopped short of

[6]Section 210(f).

Table III

PROCESS OF ESTABLISHING METHODOLOGIES

	No. of commissions
Utility filings	22
Utility filings made with PUC guidance	5
PUC sets methodology or calculates rates	12
No information	12

establishing the methodology themselves. A minority of commissions established their own methodology.

Obviously, the first approach is the most difficult for the researcher to review and analyze, and in those states which relied upon utility filings we often inferred the methodology in practice (see section D below) from the tariffs proposed by the utilities. The public utility commissions often had utilities file avoided cost "data" without any reference to a methodology for deriving it. Sometimes references to computer models or to specific plant data helped to determine the actual methodology used, but in general this approach by the public utility commissions made it difficult to determine what methodology the utility used and what restrictions, if any, on the selection of methodology were imposed by the public utility commission. Undoubtedly a few of the commissions have, by precedent, established methodologies for calculating marginal costs which were implicit in the decisions we analyzed; very often it seemed that the commission was treating the calculation of avoided costs as if the methodology was apparent.

When state commissions used staff reports or testimony or had staff propose the rule, the task of determining the public utility commission's requirements for methodology became much simpler. The issues in controversy were more clearly spelled out, and the basis of the commission's decisions was clearer. While this study presents no evidence that the first approach discussed resulted in rates not reflecting the full force of PURPA, the prevalence of states which relied upon utility filings without supplying much analysis of their own reduces our confidence that the issues were fully discussed.

2.4 Avoided Cost Methodologies

As every public utility commission adopted separate methodologies for calculating as available and firm power costs (as contemplated in the FERC rules), the methodologies which cover avoided capacity costs will be discussed separately from those which cover avoided energy costs only.

2.4.1 Avoided energy cost methodologies

The FERC rules require that all QFs be paid the avoided costs of the energy they sell to the utility. A number of factors are listed in the FERC rules, but the states were given wide latitude in establishing energy rates for QFs so long as the rates did not fall below the utility's "incremental" costs. As can be seen in Table IV, the commissions took advantage of that wide latitude by adopting many different approaches to the problem.

The avoided energy cost rates are, of course, crucial to the economics of photovoltaic systems. They are the primary source of benefits for a grid-connected photovoltaic system, and their proper calculation will assure that the appropriate incentives exist for investment in such systems.

Many public utility commissions did not establish a precise methodology for the utilities to follow in establishing avoided energy

Table IV

AVOIDED ENERGY COST METHODOLOGIES

	No. of commissions
Utility filings (no further information)	10
Incremental or decremental costs	8
Computer simulations	5
Purchased power rates (pool or supplying utility)	6
Marginal plant (utility's own or pool's)	4
System lambda	1
Other	4
Not specified/no information/unclear	15

Note: Two states gave options and are counted for each option; hence total does not add to 51.

costs but rather merely recited the requirements of the FERC rules and required the utilities to file rates which took into account the factors mentioned in the rules. Very often it was difficult to tell exactly what the utility did to calculate the avoided energy costs.

A large number of other commissions referred to incremental or decremental cost calculations without detailing exactly what methodology the utilities were to follow. Quite possibly the methodologies have been established in prior cases, but there was little to go on in the written opinions on rates for QFs.

A number of commissions used the marginal plant from the utility's entire system and determined that its fuel costs were the costs which QF power would displace. At least one state applied a similar approach, using the marginal plant within the entire state (as the utilities are interconnected) to establish avoided energy costs for all utilities within the state. In either case, the estimates of avoided energy costs are often based upon some historical (or projected) average for the plant. The average may be updated annually or quarterly, and accounting adjustments may or may not be made after the accounting period has ended, depending upon the commission's rules. Also, a different plant may be selected for calculating the off-peak rate than was selected for calculating the on-peak or, if there is one, the shoulder-period rate.

One commission may decide to use the utility's system lambda as the avoided energy cost rate. The system lambda represents the fuel cost of the plant which is the most expensive to operate at any given time. Obviously it cannot, using present metering technologies, change as the utility's dispatch of plants changes throughout the day; hence averaging based upon historical patterns, similar to the single plant method described above, must be used. Again, accounting adjustments after the fact may occur, depending upon the commission's rules.

The rates may also be established based upon rates for purchased power. In a few states, the issue of the rates used in the regional power pool arose as a possible way to establish the utilities' avoided costs, as a utility would never generate power if it cost more than the pool price and would always be able to sell any excess at that price. Again, estimates based upon historical averages would usually form the basis for rates, and accounting adjustments after the fact may occur.

The issue of rates for purchased power becomes most significant when the utility which distributes the electricity to the final customer has no generating facilities but purchases all its power needs from a generating utility. Power supplied from a QF would displace generation in the generating utility by reducing the consumption of the distributing utility. Yet the distributing utility saves only at a flat rate for the bulk power it purchases and not at the (usually higher) avoided energy cost of the generating utility. Of the three states which faced this issue, all allowed the QF only the bulk power rate available to the distributing utility.

When the distributing utility is a subsidiary of the generating utility, the issue becomes very problematical; it is usually complicated further because the rates for the bulk power sale are not under the control of the state public utility commission but rather are within FERC's jurisdiction. As wheeling cannot be required in most cases except by FERC because the power would be crossing state lines, the state public utility commission cannot order the generating utility to pay its avoided costs to the QF, even though in fact it is the generating utility which is avoiding generating costs. On the petition of the Massachusetts Department of Public Utilities, this matter is presently before FERC. Its potential significance for photovoltaic power producers is obvious.

Table V

OTHER COSTS INCLUDED IN AVOIDED ENERGY COSTS

	No. of commissions
Variable operating and maintenance costs:	
Included	20
Not specified	18
No information/unclear	13
Line losses:	
Included	22
Not specified	18
No information	11

Note: Only one state included transmission line losses but excluded distribution line losses.

The issue of averaging over the different time periods (peak/off-peak, quarter, year, etc.) may also be potentially serious for photovoltaic power producers, depending upon how wide the peak period is, whether there is a peak period at all, and to what extent seasonal variations are reflected in the avoided energy cost calculations. Also, to the extent that such averaging fails to fully represent the instantaneous coincidence of load and power supply which photovoltaic systems might produce, the averaging will produce a rate which provides an improper incentive for photovoltaic power producers to build systems.

Treatment of two potential components of avoided energy costs other than fuel costs has not been uniform across the states, as Table V demonstrates. Approximately half the state public utility commissions require that variable operating and maintenance expenses be included in the calculation of avoided energy costs; in the other states the issue often did not arise. Also, transmission and distribution system line losses were required by about half the states. Occasionally sufficient facts to support an adjustment to the avoided energy cost calculation were not available. While both of these components are elements of the incremental cost of electricity, neither is very large, and they may not be that important to the economics of photovoltaic systems.

2.4.2 Avoided capacity cost methodologies

The FERC rules make it clear that QFs should receive capacity credits if they allow the utility to avoid construction of new capacity or purchase of capacity from other utilities. The comments to the rules make it clear that 100% reliability of the QF is not essential before the QF becomes entitled to the capacity credit. For example, in the case of photovoltaic systems there would be some reliability in a statistical sense, even though the system's output is weather-dependent and only occurs during the day. Also, the value of such QFs in the aggregate may result in a capacity credit even if singly they do not produce reliable capacity.

Two public utility commissions did not establish capacity credits for QFs because the utilities within their jurisdiction presently have excess capacity. Three others seemed to require a greater degree of firmness in the supply of capacity from the QF than the FERC rules seem to imply. As the FERC rules gave the commissions scant guidance on how to adjust for less than 100% reliability, some commissions simply reduced the calculation of avoided capacity cost by the percentage unreliability of the QF (100 minus the percent reliability). In general, as no clear and simple method for adjusting the capacity credit appeared to be available, the commissions selected convenient methods.

When a public utility commission did attempt to establish a methodology for calculating avoided capacity costs, it was usually faced with a choice of a simple method which could be easily verified or a more complex one using computer simulation models which, although technically more appealing, was difficult to implement. As Table VI demonstrates, many commissions chose the simple method of calculating the value to the utility of postponing a scheduled plant for a certain period; the longer or larger the postponement, the greater the avoided capacity cost. Almost as many others simply used the list of factors in the FERC rules without articulating how they were to be converted into a methodology. Only a handful of commissions required the use of large computer models designed to help utilities optimize their capacity expansion planning.

A few other methodologies were selected. One called for using the rates for the purchase and sale of capacity in the regional electric pool, a simple method which has the further advantage of taking into account the reality of power pools. Two commissions referred to differential revenue requirements methodologies which calculate revenue requirements with versus without QFs connected to the utility system. Perhaps this type of methodology implicitly includes some form of capacity expansion planning. Two commissions referred to long-run incremental cost methodologies which may also refer to some sort of capacity expansion planning.

Table VI

AVOIDED CAPACITY COST METHODOLOGIES

	No. of commissions
Deferral of planned expansion	12
FERC factors	9
Capacity expansion planning models	4
Power pool rates	3
Long-run incremental costs	2
Differential revenue requirements	2
No credits due to excess capacity	2
Unclear/utility-determined/other	6
Not specified/no information	14

Only three commissions explicitly linked the calculation of energy and capacity avoided costs for situations in which a QF provided capacity. In other words, when a QF would earn a capacity credit because, for example, the utility could then defer construction of a new generation plant, the commission should also require that the energy component of the QF's payment be derived from that same plant. Two methods for calculating the capacity credit, namely the generation expansion planning method and the differential revenue requirements method, may link the calculation of energy and capacity credits, depending upon how they are applied; however, only three commissions addressed the issue explicitly.

In any event, some commissions appeared to be stating the capacity value of photovoltaic systems or other stochastic small power producers conservatively. While this will not be a problem for potential photovoltaic power producers now, as they will be replacing the generation of expensive oil-fired plants, it may become a problem when the nation's utilities' have largely switched away from oil to coal or some other fuel source which is more capital-intensive. At that point some of these methodologies may not give weather-dependent power generation sources such as photovoltaics the full capacity credit they deserve, and their economic desirability may be unreasonably harmed.

Table VII shows that only 14 commissions considered the issue of technology-specific rates for QFs. Of those 14, only five actually considered specific technologies, and no details were given about how to arrive at such a rate. The idea of technology-specific rates appears to be a bit ahead of its time.

2.5 Interconnection requirements

The interconnection requirements which public utility commissions establish for QFs, while not reflected in the avoided cost rates for purchase of QF power, will probably have the greatest affect upon the economics of photovoltaic systems of any of the PURPA requirements. They have the potential to make balance-of-system costs very high, consuming almost all the system's economic benefits, thus leaving little or no room

Table VII

EXISTENCE OF TECHNOLOGY-SPECIFIC RATES

	No. of commissions
Technology-specific rates allowed	14
Not allowed/Not specified	25
No information	11
Frequency of mention of specific technologies:	
Not specified	9
Wind	3
(Denied for wind)	1
Photovoltaics	2
Hydroelectric	1
Weather-dependent	1

Note: Some commissions mentioned more than one technology; hence total does not add to 14.

for the costs of the module or other components of the photovoltaic system.

Also, little is known about the consequences of interconnection of many small power producers to the utility grid. Issues of safety and power quality are legitimate concerns of public utility commissions and utilities, yet the nearly total absence of accepted standards for such interconnections makes reasoned decision-making difficult.

In the absence of much firm technical consensus on these matters, many commissions have had little choice but to take the utility's requirements practically on faith. Though the utility's requirements are offered in good faith, they are offered without much factual support, and the requirements could be excessive. Table VIII shows the level of guidance which public utility commissions were able to give in the area of setting safety standards for interconnection.

Table VIII

ESTABLISHMENT OF SAFETY REQUIREMENTS FOR QFS

	No. of commissions
Public utility commission	4
Utility, subject to review by commission	13
Utility with little or no guidance	15
Not specified/no information	10

The majority of public utility commissions have required that QFs pay only the "extra" costs of interconnection, as Table IX shows. These costs may cover switching equipment, protective devices for utility equipment and personnel, power conditioning and wave synchronization equipment, metering, and other costs which would not be incurred if the customer were not supplying power to the utility. Yet often the commissions do not, due to their lack of expertise in these matters, specify exactly what equipment is required and what level of equipment will suffice. Of the 15 commissions which itemized requirements, none established firm technical requirements for the interconnection. Very often the commission will defer to the utility's judgment in such matters; seven commissions referred to the handful of IEEE or other electrical standards in existence or to standard practice in the utility industry, even though utility practice regarding interconnection with QFs is far from standardized.

One requirement relating to interconnection which has occasionally arisen is that of indemnity insurance purchased by the QF to cover any possible harm to the utility's equipment and personnel. This has varied

Table IX

INTERCONNECTION COSTS ALLOCATED TO QF

	No. of commissions
Excess over ordinary interconnection costs	27
Itemized functional or hardware requirements	15
Indemnification of utility required	6
Not specified	5
No information	11

Note: A number of states fall into two or more categories; hence the total does not add to 51.

from a requirement that the QF purchase a "commercially reasonable" amount of liability insurance to the requirement that the QF purchase a $1,000,000 indemnification policy. Although the latter case is the exception, establishing what is a commercially reasonable level of insurance to require would reduce the chances that this requirement will become an unreasonable hindrance to photovoltaic development.

To mitigate against the concerns about possible utility overkill in these areas, many commissions have adopted review or appeal procedures for cases in which the utility and the putative QF cannot agree upon an appropriate interconnection. These procedures should help some, but they, too, must rely upon the scant technical consensus on what specific hardware is required for a safe and reliable interconnection.

2.6 <u>Wheeling</u>

The FERC rules allow for utility wheeling of QF power with the QF's consent but do not mandate the utility to wheel the QF's power unless the utility also consents. Although, as Table X shows, the wheeling issue did not arise in many jurisdictions, when it did the public utility commissions usually applied the FERC rules requiring mutual consent.

Table X

COMMISSION POLICIES ON WHEELING

	No. of commissions
Both utility and QF must give consent	0
Only QF's consent mentioned	3
Only utility's consent mentioned	2
Wheeling is outside state's jurisdiction	2
Not specified or case-by-case review	25
No information	11

As discussed above, the issue of which utility's costs are avoided became an important issue for non-generating utilities and for utilities in regions where pooling practices are well-established. The selection of the pool's system lambda or the generating utility's avoided costs as the basis for the rates for purchase of QF power has the same effect as forced wheeling. When the public utility commissions so act, concerns about utility reluctance to wheel and utility wheeling charges fade into the background. However, in those jurisdictions where the issue of which utility's costs are avoided was not faced, utility reluctance to wheel may be a problem.

One commission developed a rather innovative approach to the issue. New Mexico gives the utility to which the QF is interconnected the right of first refusal on the QF's power. Should the utility refuse the power, the QF may sell it to another utility which then would sell it back to the interconnected utility or make arrangements for its wheeling. It will be interesting to see if the New Mexico experiment works.

2.7 Rates for Auxiliary Power

The FERC rules require utilities to offer four types of auxiliary power (backup, maintenance, supplementary, and interruptible) to QFs. The availability of auxiliary power at reasonable costs is economically important when the QF is operating in parallel with the utility, taking only its needs from the grid and selling its excess to the grid, as it affects the overall system benefits. When the QF sells all its power to the grid and isolates its load from its own power supply, thereby using utility power to meet its entire load, the QF's load would be treated like any other retail customer's, and the issue of rates for auxiliary power would not arise.

While there are conceptual differences among the four rates, many public utility commissions treated them as a block, not discussing any differences among them beyond copying the definitions in the FERC rules. As no good reason for distinguishing among the rates appears so long as auxiliary power is offered in all four situations, the issue of effective compliance appears to be resolved.

More interesting, however, is the level of the rates relative to the avoided costs for purchase of QF power and to "ordinary" retail rates. Table XI shows that only a few commissions have seen fit to allow differences. In some cases the rate for auxiliary power was the same as the avoided-cost rate for purchase of QF power, especially in situations where the utility was required to pay for net (rather than gross) purchases from the QF. Such situations usually involved a two-way metering arrangement. More frequently, however, the commission would require that QFs pay for this power at retail rates for customers with similar load characteristics.

Two issues arise with this latter formulation. First, no public utility commission spent very much effort defining what "similar load

Table XI

COMMISSION POLICIES ON QF PURCHASES OF UTILITY POWER

	No. of commissions
Availability of utility power:	
All four rates available	25
All four rates available upon request	1
Three rates available	1
Two rates available	2
Same as for customers with similar loads	1
Not specified	10
No information	11
Differences from ordinary rates:	
Not specified/Repeat of FERC rules	34
Special rates allowed	5
No information	11

characteristics" might mean for particular technologies. It is hard to conceive of a class of customers existing today which shows consumption patterns similar to those which owners of photovoltaic systems might have, i.e. reduced midday consumption. While there is no evidence that this is a problem yet, it may become so in the future.

Second, charging retail rates to QFs for auxiliary power may result in inappropriate charges, particularly demand charges. For example, many commercial tariffs charge customers for their peak usage during a particular billing period. If a QF stops producing power for the fifteen minutes when it (or the system, depending upon the tariff) experiences peak demand, it may incur just as high a demand charge as if it had produced no power during the billing period. Several public utility commissions are concerned about this issue, although their actions are not always clear on the issue. At least one has determined that, since the utility is legally obligated to supply the power to the QF, it cannot charge a demand charge. As that reasoning would appear to apply equally as well to ordinary commercial ratepayers, it probably will not be the solution which most public utility commissions adopt. Hence this issue merits watching, as it may become a problem for certain photovoltaic systems in certain applications.

3.0 Summary and Conclusions

Several important conclusions can be drawn regarding the effects of state public utility commissions' actions upon penetration of photovoltaic systems into the utility grid. These conclusions are discussed below.

First, it seems fairly clear that PURPA has done much to open the doors for small power producers. The question facing the utility and the QF is no longer whether a deal can be struck, but rather at what price. Whether PURPA has placed the QF in an equal bargaining position with the utility is not clear as yet, however; it would be wise to see what develops in the future.

Second, while PURPA has helped to make utilities responsive to QF-generated power, it has not resulted in a uniform system of setting rates for the purchase of that power. Furthermore, because of the practice of many commissions in relying upon utility filings, it is difficult to determine exactly how the rates are set, hence making federal oversight of the rate-setting difficult and thereby allowing a diversity of state practices to flourish. While this diversity may be helpful in allowing "good" methods of establishing these rates develop, it may ultimately become a hindrance to potential QFs as each state's practice must be understood before a manufacturer is willing to invest in building a distribution network in a particular state. Also, it may be that commission reliance upon utility filings may result in lower rates for QF power than would result through staff-proposed rates; further study may be warranted.

Third, the issue which has the greatest potential for ultimately affecting the economic value of photovoltaic systems to prospective investors is the interconnection issue. The commission requirements for safety, operating reliability, and other interconnection problems are often based upon utility filings, as there is little technical consensus to which the commissions can refer. As the costs of these requirements can consume much of the economic benefits of photovoltaic systems, it is important that they be made reasonable. Providing an adequate technical basis to which commissions, utilities, and QFs alike can refer would help to ensure that the requirements are reasonable.

Fourth, the question of the rates to be set by non-generating utilities must be addressed at a federal level. Allowing distributing utilities to pay only the flat bulk power (i.e. average) costs which they avoid even though the generating utilities are avoiding marginal (usually oil-fired) costs will discourage the introduction of photovoltaic systems and other QFs. The availability of forced wheeling to the generating utility is a closely related issue which should also be addressed. A pending case before FERC may resolve the first half of this matter, and it should be watched.

Fifth, improper setting of rates for auxiliary power may detract from the economics of systems operated in parallel with the utility. Very little guidance has been given at present by FERC on this matter.

Demand charges which were established for customers which only consumed power and did not generate it may or may not overstate reasonable charges; without examination on a utility-by-utility basis exactly what costs are being ascribed to the demand charge, it is not possible to tell whether the charges are high or low. If demand charges prove to be a hindrance to the introduction of photovoltaic systems systems operating in parallel with the utility, and if the other alternative (simultaneous purchase and sale) proves infeasible for economic or technical reasons, the matter may then require a closer look and some federal action.

Finally, questions about the general design of PURPA's section 210, which places responsibility upon the state public utility commissions for implementing the federal policies in favor of cogeneration and small power production, must be raised. Time after time it became apparent that many commissions were straining their expertise to deal with particular issues. Often issues were simply not faced. Whether another regulatory design, with more centralized control in the hands of federal officials, would be more effective is unclear. Perhaps the existing framework best allows for experimentation with regulatory practice while the underlying arrangements are worked out in the field.

Of all the issues discussed above, the most important one at present, from the point of view of break-even economics of QFs, is the interconnection issue. The other issues will take a while to mature and will invariably require further study when they do, but the interconnection issue is real, is current, and is something for which relevant technical information can be developed.

Chapter 7

Perspectives on the Government Role in New Technology Development and Diffusion

Drew Bottaro

Paul R. Carpenter

Richard D. Tabors

1.0 Introduction

The last two decades have seen a considerable expansion in the level of direct governmental involvement in technology develoment, particularly in energy related technologies. The last year has seen a dramatic retreat from this policy. Is there any sense that we can say that the particular program activities which constituted this expansion and now the retreat were based on sound economic criteria? Why does the discussion of federal involvement in technology development and diffusion (also known as "commercialization") seem so mind-numbing? Are economists part of the problem of lack of focus in this debate or are we part of the solution? Our four years of direct involvement in the solar photovoltaic conversion technology development programs has led us to reexamine these questions.

Economists have been fond of using the concept of market failures or externalities to justify government involvement in technology development. But coincidentally, we have also been fond of arguing that none of these failures prescribe government involvement on a <u>technology-specific</u> basis. As George Eads observed a decade ago, we have left policy makers and program managers with little to guide them in the decision to fund or to design and manage these programs:

> This gap is caused in part by the fact that the theory of externalities and the conditions under which its simplest prediction

is a proper guide to policy have not been clearly understood by those formulating U.S. government science and technology policy. This misunderstanding has been abetted by the failure of economists to present the theory of externalities in an operational form. We economists have given policy makers a theory that possesses a great deal of political attractiveness, but we have failed to develop the tools that would allow us either to show those government officials charged with implementing science policy how the theory should be applied in specific cases or to demonstrate to them and to the public that the theory is being misapplied.[1]

While we do not propose to provide all of these tools in this chapter, we do propose to present a framework around which the theory can be made relevant to the program manager.

The remainder of this chapter is divided into two major sections which correspond to the questions whether (is there a government role?) and how (if the government is involved, how should these programs be designed and managed?). In the first section we will characterize the traditional economic literature on this subject and present the market failure concept as we believe it relates to technology-specific activities. In the "how" section a framework for program design will be presented and the example of solar photovoltaic technology will be used to illustrate its use. This section and the chapter will close with some comments on the problems inherent in government-managed programs with some suggestions for improvements as well as a discussion of industry market structure and its implications for program management.

2.0 Is There an Appropriate Government Role?

2.1 Current Theories

Like the Little Prince's geographer, the economists who have

---

[1]George Eads, "US Government Support for Civilian Technology: Economic Theory Versus Political Practice," Research Policy, Vol. 3, 1974, p. 2-16. (Emphasis added).

contributed to this field have largely been concerned with the "whether" question and not the "how". While it is not immediately obvious that the literature falls into a convenient classification scheme, we detect a spectrum of approaches that range from a direct frontal assault from a theory perspective to a case study approach that evaluates past program successes and failures. The work which best represents the theory perspective and the only paper that to our knowledge treats the question of whether government support should be given on a technology-specific basis is Schmalensee (1979).[2,3] This work contributes three valuable conclusions with regard to the government role question:

- o There is no efficiency basis for treating energy technologies as a special case even under domestic energy price controls. (The "why not textiles?" argument).
- o When domestic energy prices are less than world prices and in a world of certainty, general output-subsidies are usually superior to selective input-subsidies.
- o With decontrolled domestic prices and in an uncertain world, selective governmental intervention may be warranted if there are market failures associated with buyer information, or institutional problems in the appropriation of benefits. (Schmalensee finds this case unpersuasive and warns that governments, like markets, are also imperfect.)

This third conclusion is only briefly developed in Schmalensee, but unfortunately it is the only one of immediate relevance to our concerns here.[4]

---

[2]Richard Schmalensee, Appropriate Government Policy Toward Commercialization of New Energy Supply Technologies, MIT Energy Lab. Working Paper 79-052WP, October 1979.

[3]Other work here includes Eads, op. cit.; Nelson, Richard, The Moon and the Ghetto, New York: Norton, 1977; Joskow, Paul and Robert Pindyck, Should the Government Subsidize Non-conventional Energy Supplies?, MIT-EL 79-003WP, MIT Energy Laboratory, 1979.

[4]Our analysis should not be construed as being limited to energy technologies, and for all intents and purposes domestic energy prices have been, or will be, decontrolled. Finally, we live in an uncertain world where it is not generally possible to write perfect contingent claims contracts.

The other end of the literature spectrum is represented by the Rand Corporation's study of the factors which led to the success or failure of 24 government-supported commercial demonstration projects.[5] The important conclusions of this study have to do with when demonstration projects (one of may potential activities, as will be discussed later) are likely to be successful. Rand argued on the basis of the cases studied that the technolgoy must be "well-in-hand" to show significant diffusion after the demonstration. This work does not and was not intended to address the more general question of the government role beyond demonstration projects nor does it discuss how demonstration projects fit into the entire "commercialization process."

The concept of a "commercialization process" from basic research through diffusion is not new in any sense, having been developed at some length in the R&D management literature. It was connected with the concept of market failures in an energy market context by the MIT Energy Laboratory Policy Study Group work[6] in 1976. This final piece of the literature is a start at drawing the linkage between the motivation for government support and program design and management. Unfortunately, the MIT report does not distinguish between market failures which justify technology-specific activities and those that do not. Rather, it breaks down the technology development process by stages and analyzes the appropriateness of the governmental role as a function of the technology's developmental stage.

---

[5] Baer, W., et. al, "Analysis of Federally Funded Demonstration Projects," The Rand Corporation, R-1925-DOC, April 1976.

[6] MIT Energy Lab Policy Study Group, "Government Support for the Commercialization of New Energy Technologies," MIT-EL 76-009, November 1976.

In the remainder of this section we examine briefly the market failures which are inherent in the development of new technologies. Some, we believe, justify technology-specific involvement by the government; our reasons are spelled out. Finally, we examine briefly but do not attempt to resolve the issue of evaluating the severity of these market failures.

2.2 Traditional Justifications for Governmental Involvement in New Technology Development

Several market failures are commonly used to justify governmental intervention in the development of new technologies. They range from price problems to various market uncertainties to market structure concerns; a brief review of them will set the subsequent discussion.

Perhaps the most commonly discussed market failure in the energy field is incorrect prices. Typically, price distortions in oil and gas markets are raised, although coal, nuclear, and electricity are also portrayed as victims of this market failure. Its sources are usually ascribed to non-competitive market structures (e.g., OPEC), price regulation (price controls or rate regulation), and subsidies (e.g., the oil depletion allowance). These price distortions can lead to underinvestment in new energy technologies which, it is often argued, make governmental intervention into development of those technologies desirable.

Imperfect information flow between producers and consumers is also raised as a source of market failure. The inability of consumers to convey to producers exactly what their needs are results in some uncertainties in the profits producers will realize from investments in new technology production equipment; hence they tend to underinvest in such equipment. Similarly, the inability of producers to describe exactly the characteristics of their products results in some consumer uncertainty regarding the product and hence some underconsumption which results in underinvestment.

A similar market failure involves the coordination necessary between developers of the new technology and developers of the production equipment for the new technology, as they are often not the same. This market failure is obviously more applicable to technologies which will be produced in quantity such as ultra-sound scanners or heat pumps.

If the benefits which flow from the development of a new technology cannot entirely be captured by the innovator, a diminished incentive to invest in the development of new technologies results. This inappropriability of the innovation's benefits should be alleviated by the availability of patents; there are those who would argue about the efficacy of our patent system.

Finally, the existence of a non-competitive market structure has been alleged to inhibit the development of new technologies. The Schumpeterian hypothesis argues the contrary, however, and the evidence is not entirely persuasive on either side.

2.3 Justifications for Technology-Specific Governmental Involvement in New Technology Development

In general, the above market failures may provide justification for governmental involvement in new technology development, depending upon their significance. Whether action should be taken on a broad basis which is technology-neutral or whether it should occur on a technology-specific basis is another matter. Technology-neutral actions do not select particular technologies such as "semiconductors" or "oil shale" as targets for government funding, whereas technology-specific actions do so select, often in the form of "programs" for particular technologies.

While in theory technology-neutral governmental action is optimal, it is not clear how to design programs which are even-handed across all technologies. For example, how does one develop a tax credit based upon the degree of information imperfection existing in a market? And who receives the tax credit? Obviously some classification of potential recipients according to the particular technologies is essential or else the IRS cannot determine how much credit to allow to whom.

1. Output versus input subsidies

Previous analysis of the question of technology-neutral versus technology-specific governmental involvement has taken the form of a discussion of the relative merits of input subsidies as compared to output subsidies. Input subsidies are awarded to various inputs to the technology development process; some examples include grants for prototype testing and for research on various aspects of the technology's design or operation. Output subsidies are awarded on the basis of the technology's energy output. Output subsidies, it is argued, are technology-neutral; any technology which produces the desired output receives the subsidy. Input subsidies, on the other hand, can do no better than output subsidies because at best they will duplicate the results of the technology-neutral output subsidies and at worst they will subsidize unfruitful technologies at the expense of ones which, ad hoc, would have been successful.

But are output subsidies really feasible? Perhaps they make some sense for synthetic fuels and other new energy supply technologies, but they make little sense in other instances. Indeed, some of the problems make them seem more clumsy than input subsidies; one serious practical problem, apparent with the solar tax credits, is the inability to predict budgetary impacts with any reasonable accuracy.

One large problem arises in applying them to energy conversion technologies, which include heat pumps as well as conventional heating systems; both convert energy in the form of electric or chemical potential into kinetic energy in the form of heat. Clearly the "output" from such technologies depends upon the capital and energy inputs. An output subsidy would give a greater subsidy to a large, energy-inefficient conversion device than to a small, efficient one, even if capital costs per unit output were identical! The problem here is that it is not obvious what the output measure should be: BTU-equivalents, barrels of oil displaced, or some other measure.

The existence of output subsidies, while useful in some contexts, is not in itself sufficient for denying or minimizing the need for technology-specific governmental assistance for development of new energy technologies. It is now appropriate to examine reasons why a need does exist for technology-specific action in certain instances.

2. Market failures which justify technology-specific governmental involvement

Of the five market failures listed in section II.B above, we argue that some of them justify technology-specific action by government while others do not. We begin by dismissing those which do not seem to warrant technology-specific governmental involvement.

First, the problem of mispriced energy supplies is addressable better through changes in price controls or, should that prove politically or institutionally infeasible, price subsidies to alternative fuel supply technologies. The effects of incorrect energy prices are widespread and the adjustments which must be made in response to them pertain to many technologies. Ideally these subsidies can be made technology-neutral, though there may be some problems even with that, as the preceding discussion indicates. In any event, we do not think that incorrect energy prices are a sufficient justification for technology-specific programs in most instances.

Also, the problems of non-competitive market structures and their implications for new technology development do not constitute a sufficient basis for technology-specific intervention into the marketplace. In our opinion, the evidence to date on the consequences of market concentration upon innovation is not persuasive enough to rest governmental involvement solely on this market failure. Indeed, the Schumpeterian hypothesis argues to the contrary. Should this thorny issue become better resolved within the economics profession, perhaps undue market concentration could become a satisfactory basis for action; that time has not yet arrived.

We do think that the other identified market failures are sufficient in themselves for technology-specific governmental involvement, assuming they are sufficient in magnitude. The inappropriability of the benefits of new technology development is likely to vary from technology to technology; some technologies exhibit highly localized learning effects while others do not. The differences in the localizability of benefits have little or nothing to do with the potential value of the different technologies but are artifacts of the particular technologies involved and the extent of relevant technological progress that has occurred to date. Furthermore, determining the appropriate level of governmental involvement to alleviate this market failure requires a fair knowledge about the technological opportunities facing society; the governmental action, in whatever form it ultimately takes, is likely to take into account the specifics of the technologies examined rather than attempt to devise a generally applicable formula for lending support.

The other two market failures (imperfect information flow and lack of coordination between producers and technology developers) both pertain to information asymmetries among actors in the marketplace. How significant these asymmetries are will vary from technology to technology, again without regard to the potential value to society of the various technologies. Some of the miscoordinations may even be due to institutional barriers created by the government. In any event, any governmental involvement in these problems is likely to come through technology-specific actions rather than attempts at broad-scale structural changes within society.

These arguments hold, we believe, in a first-best world where no impediments to reaching equilibrium exist. We believe they are made stronger in a second-best world in which the market failures we have identified have been technology-specific and, in effect, have favored existing technologies.

> What is readily apparent is that the appropriate degree of compensation for any tendency to underinvest will vary widely by industry. This suggests that industry-specific programs are more likely to produce appropriate results than are programs applicable to all industries.[7]

We are somewhat comforted in our views by a comparison to recent views on the behavior of the Japanese government in relation to its industry. Far from the popularized view of "Japan, Inc.," this

---

[7] Eads, op. cit. p. 7.

government seems to be involved in its industry in two ways.

First, it insures the availability of one key resource--trained professionals--to industry. In addition, it finances cooperative applied research and experimental development in technology-specific areas of significance (e.g., shipbuilding). The actual commercial development of the resulting products or processes is left to industry. In this fashion Japan deals directly with the inappropriability market failure.

Second, it provides export market assistance in the form of an organized export trading ministry. In this manner Japan helps to alleviate the information and coordination problems associated with emerging technologies.

2.3 Evaluating the Significance of Failures in Markets for Developing Technologies

We have identified two types of market failures which justify technology-specific intervention in the marketplace. However, as all market failures are present to some degree or another in all markets, the question ultimately becomes one of evaluating their significance.

Measuring the significance of failures in particular markets would help immensely in determining whether technology-specific action is warranted. Unfortunately, econometric measurement techniques are not precise enough to give solid quantitative answers to these questions.[8] Hence, the judgments of many on the significance of particular market failures all too often seems to be subjective. The need for more detached analysis is strong and would go far in improving the quality of

---

[8]For an attempt to quantify learning effects in the case of nuclear power, see Zimmerman, Martin, "Learning Effects and the Commercialization of New Energy Technologies: The Case of Nuclear Power," prepublication draft, MIT Sloan School of Management, June 1981.

policy analyses concerning government involvement in new technology development and the strength of the resulting recommendations.

We do not pretend to address this issue beyond merely pointing out its importance. Its significance for the present discussion, however, is that if we do not have precise knowledge of the extent of these market failures, then of necessity we are operating in a situation in which bounded rationality reigns. Alternatives must be compared by policymakers on the basis of scant knowledge, and decisions will be made.

What is the role of the economist giving policy recommendations in this case? The decisions to be faced are often political. Without hard numbers the economist's role is largely advisory. Nevertheless, the economist can establish broad principles for future decisions which are as far removed from subjectivity as possible. We have presented our views for discussion on what those principles should be when the question is whether to embark upon a technology-specific governmental program. The economist's role need not end here, however. As there are times when technology-specific programs are warranted, the questions of how to manage such programs and, perhaps more importantly, when to stop them, will benefit from discussion by economists. The following section presents our framework for approaching these issues.

3.0 Designing and Evaluating Commercialization Programs

Once the decision has been made about the need for developing a particular technology through the use of a technology-specific governmental program, the questions of designing that program and evaluating its continued usefulness must be explored. This section provides a framework for approaching two basic questions concerning program design and evaluation. First, what are the activities which the technology-specific program should include in its design? Second, at what point should the governmental involvement stop?

The example of photovoltaics is presented to provide a context for the framework's subsequent discussion. In essence, the framework presents methods for characterizing, in relatively simple terms, the products which a technology-specific governmental program should produce as they relate to the stages of development of each aspect of the technology. These two dimensions of the process are combined into a matrix which is then used to determine which technological products at which stages of development are to be the objects of technology-specific governmental attention, and for how long.

3.1 Basic Photovoltaic Technology

The Department of Energy has pursued a program for developing photovoltaics over the past several years. The program's content has changed somewhat from year to year as funding levels has risen and fallen. The salient characteristics of the technology are presented below.

Photovoltaics convert sunlight and other solar radiation into direct current electricity through the use of thin semiconductors, usually in wafer form, which produce their power when exposed to the sun. At current prices photovoltaics systems are upwards of ten times the prices they would have to be to compete effectively with centrally-generated electric power. The governmental efforts to date have focused upon ways to lower present prices by addressing several aspects of photovoltaics technology.

Materials: Most photovoltaics semiconductors are made from

Technology "Products"	Problem-solving "Roles"			
	Basic Research	Technology Development	Engineering Development	Market Development
Raw Materials	A	A,B		
Production Process	A	A,B		
Device			B	b
Final Product				b

A = Inappropriability

B = Coordination

crystalline silicon, which is expensive and accounts for much of the high cost of photovoltaics. Efforts to reduce the costs here have examined materials other than silicon and ways to produce crystalline silicon from its raw material (sand or quartzite) more cheaply.

Production: Currently most photovoltaics modules are made by slicing crystalline silicon ingots into wafers, turning the wafers into semiconductors, connecting them by soldering, and encapsulating them. Automating many of these procedures would result in economies of scale in production and would reduce the cost greatly.

Module: Photovoltaics are currently made into modules with metal substrates and glass covers of dimension 1' x 4'. Increasing the size may reduce costs. Also, innovative concepts which abandon the notion of a module include rooftop photovoltaics shingles which would theoretically save installation costs.

Photovoltaics system: Photovoltaics modules produce direct current. In order to meet most electrical needs of today, this must be inverted into alternating current at 60 hz. Furthermore, the waveform of the resulting alternating current must be close to a particular shape; this is achieved through power conditioning devices. The complete system must also be installed safely and economically.

Efforts here have tried to reduce the power conditioning device and installation costs, in some cases by trying to combine the inverter and the power conditioning equipment into a single device.

3.2 Delineating an Appropriate Governmental Role

What follows is a suggested framework for delineating the proper governmental involvement in a particular technology's development. It begins with the nature of the technology in question, proceeds to a discussion of the different roles possible (grouping them according to their relationship to stages of technological and commercial development), and describes how the framework can be used to design or evaluate technology-specific governmental programs. The case of photovoltaics is used to demonstrate the use of the framework.

1. Technology Products of Governmental Involvement

Initially one must determine what technological progress has to occur before a new technology becomes successfully integrated into the marketplace. While this may seem rather obvious, it provides one way of describing the content of a technology-specific governmental program. It indicates what research and engineering obstacles must be overcome before the technology can be called a market success. The definition of success is, of course, relative to the market as that determines whether the ultimate product will achieve widespread diffusion.

The technological progress needed to get from the existing state of technology to the desired one can be represented as a series of "technology products". A technology product is an engineering advance which either increases capabilities or reduces costs. The series of technology products summarizes the technological roadmap for getting from here to there and is useful in assessing alternative technological strategies.

One way to characterize the technology products is according to their upstream-downstream sequence in production. For example, in the photovoltaics case described above, the "technology" is described from the point of crystal manufacture to the installation of a complete system. The key features of the technology which were described were those for which some innovation was possible which would help reduce costs to an acceptable level. The potential innovations were grouped into four broad categories: materials, production processes, photovoltaic device, and photovoltaics system. More generally, these could be described as raw materials, production processes, device, and final product.

These four categories of technology products can be used to describe most technology development situations. Not every new energy technology will have technology products in each category; however, this does not diminish the usefulness of the categories. For example, oil shale technology products would not include anything in the device or final product categories as the oil shale production process results in (somewhat tautologically) shale oil; shale oil is almost exactly analogous to petroleum-based oil (hence no need for "device" technology products as the device is already in the market) and it does not need additional equipment to make it marketable (hence no need for "final product" technology products). Using these categories focuses attention on the first two for the oil shale case. On the other hand, for a technology such as photovoltaics, technology products are required in all four categories, and their use ensures that any program will not omit key technology products such as installation procedures and power conditioning equipment.

2. Problem-solving Roles Which Government May Play

The roles which government may play in developing a particular technology product vary with the distance from the existing state of the technology to the desired one. This distance is typically measured by phases of technological development. While there are many different paradigms for phases of the innovation process, they are all fairly similar, and we use one in which an innovation moves from basic research through technology, engineering, and market development. These phases are described in some detail below.

As a technology undergoes change, it passes through the four phases on its way to becoming commercial, each phase being characterized by different types of information development and transmission. The strict sequence of the phases should not be given sacramental importance, as it is only an approximation of the actual timing. The point to emphasize here is that because of the differences in information developed and transmitted in each phase, the governmental problem-solving role changes also. This point will be discussed further in subsection 3.3 below.

Basic Research: Basic research involves scientific investigation aimed toward understanding the scientific principles underlying the behavior of things. It does not necessarily aim toward a specific solution but rather toward the development of basic information which may spur innovation. In the context of a technology-specific governmental program, this basic information is helpful in selecting the overall strategy for achieving the desired technological progress. For example, in photovoltaics the research into basic properties of different semiconductor materials helps in selecting among crystalline silicon and the other options for reducing the cost of the materials.

Technology development: As the technology develops, the eventual product begins to take on a more definite shape, and information about the processes for producing it is developed. This information is gathered by testing of prototype devices and the building and operation of pilot production facilities, among other activities. In photovoltaics, technology development activities could include both of the above, although actual efforts to date have stopped short of pilot facilities.

Engineering development: Once the device's form and characteristics are fairly well established, the device and its related system components must be proved in actual operating environments. This is often done initially with test facilities, with engineering field tests following. Photovoltaics systems were initially tested on laboratory rooftops before being tested on actual residences.

Market development: In this phase comes the first "live market" tests of the products. Possible roles for government are dwindling at this stage. Primary possibilities for governmental roles at this point could include actual market testing and broad-scale information dissemination to both potential users and affected regulatory institutions. Talk of these has occurred in the photovoltaics efforts to date. The development of information appropriate for digestion by regulatory institutions is an interesting role which one branch of government might play in trying to achieve technological change despite the actions of other branches.

This classification of potential problem-solving roles which the government may take helps in analyzing different proposals for program design or modification. As described below, it should be used in conjunction with the technology products categorization to help match governmental roles with the technology products needed.

3. Using the program design and evaluation matrix

The technology products categories and the problem-solving roles classifications can each be represented as separate axes on a matrix, as shown on the following figure. This analytical tool will help its users ask more detailed questions about the appropriateness of a selected technology-specific governmental program. In essence it decomposes the simple question of whether technology-specific involvement is warranted into a series of questions, one for each cell in the matrix. The questions become more refined, thus making the resulting analysis more satisfactory to economists and non-economists alike.

To use the matrix for designing a technology-specific program, one must simply ask whether either of the two types of market failures discussed in section II is present to a sufficient degree to warrant governmental action. If so, then the roles indicated in the horizontal axis are appropriate to include in the program for the technology products indicated on the vertical axis.

For example, we have taken the liberty to fill in the matrix for photovoltaics based on our own subjective judgment about the relative seriousness of various problems in the development of photovoltaics technology versus other possible uses of public funds. We do so in full light of the difficulties of measuring the significance mentioned in section II.D above solely for the sake of argument and not to propose that we have the "right" photovoltaics program in our grasp. We have indicated with capital letters where we think the more serious market failures are in the matrix, with lower case letters where they are less serious, and with blank areas where we do not perceive significant market failures.

Our strawman program indicates that there is an appropriate governmental role in basic research into semiconductor materials and photovoltaics production processes. As these are somewhat intertwined with some of the more radical design concepts (e.g., continuous process crystal growth and module manufacture), both technology products need coordinated research activities. The inappropriability market failure is strongly operative here.

Both kinds of market failures are operative in the technology development phase of materials and process development. Coordinaton of module designers, production process equipment suppliers, and materials suppliers (often different firms) are essential if the requisite cost reductions are to obtain. The device itself could appropriately be the object of engineering development activities as a market failure exists in the coordination between photovoltaics module manufacturers and installers.

Whether the coordination market failure is serious enough in the market development phase to warrant involvement is an open question; hence our entry of lower case letters for the device and final product. There are many institutional problems which might impede diffusion of photovoltaics technology; problems in hooking up with the local utility, problems with codes, and possibly insurance problems are a few examples. While theoretically sufficient, these problems might not be that much worse for photovoltaics than for other technologies which currently are bought and sold in the marketplace. There may be some inappropriability problems with being the first firm to resolve these institutional issues; again, the seriousness cannot be accurately estimated.

Once a program has been established, the same matrix approach can be used to evaluate how well the program is running or the desirability of modifying the program. (These days "modifying" means "cutting".) The same basic approach applies: Are the market failures which gave rise to the need for the program still serious enough to warrant continuation of each activity currently in operation or proposed for addition or deletion? Used as such, the matrix provides a convenient device to ensure that the right question gets asked.

3.3 Management Issues

As we indicated earlier in our brief characterization of the literature, Schmalense (1979) argues that in many cases "imperfections" in government management may be as serious as the market imperfections these programs are designed to correct. Our experience indicates that this concern is not to be taken lightly. In this section we will examine some of the conditions required for successful management of these programs, drawing further on the photovoltaics example. Where improvements in the current process are warranted, we will suggest them. In this connection five areas will be discussed: program flexibility, program uncertainty, political constraints, and recommendations for management organization structure.

1. Program Flexibility

One of the central themes of the framework discusson earlier was that the proper timing of certain governmental activities depends strongly on the occurrence of specific events, notably the achievement of certain technological milestones (expressed in economic terms) and the relative economics of different market segments. Since no one can perfectly forecast these events, multi-year program design must be based on an educated expectation of and variance around their occurrence contingent, of course, on budget levels.[9] By necessity, then, the

[9]The best way to make these determinators (eliciting expert judgement) is an important area of research. The record with respect to cost estiamtion has historically been bleak; c.f. Merrow, Edward, et al., A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, R-2481-DOE, Santa Monica, California: The Rand Corporation, 1979.

program must be flexible enough to be modified (even terminated) should expectations or conditions change. For example, should world energy prices rise faster than expected or should the costs of nuclear energy or coal-fired power plants become more prohibitive than expected, technology development objectives may be better served by a greater emphasis on flat-plate silicon photovoltaic technology serving central station utility needs than waiting to make central station engineering development decisions based primarily on the availability of photovoltaics made from exotic materials (e.g., amorphous silicon). Conversely, should (for whatever reason) the expectation of the availability of low-cost flat-plate silicon photovoltaics shift from 1982 to 1984, then engineering development activities relying on flat-plate silicon technology and its expected cost should probably also be delayed.

These program flexibility concerns underscore the need for analysis and evaluation capability in the management organization. Of particular importance are costing capabilities which allow the detailed examination of the effects of scale, materials, and process modifications[10] on product cost, and market analysis tools which estimate market potential based on product performance, price and the cost of alternatives. Technology and engineering development activities should include the use of field experiments and controlled market research to calibrate and verify the results of these analysis tools.[11]

---

[10] See for example, R.G. Chamberlain, A Normative Price for a Manufactured Product: The SAMICS Methodology, DOE/JPL-1012-7975, Jet Propulsion Laboratory, Pasadena, January 15, 1979.

[11] G.L. Lilien, The Diffusion of Photovoltaics: Background, Modeling, Calibration and Implications for Government Policy, MIT-EL 78-019, MIT Energy Laboratory, Cambridge, Massachusetts, May 1978.

2. Program Uncertainty

Since one Congress cannot bind the next, future U.S. legislation affecting energy market must be treated as in part random. Similarly, the future actions of state and Federal regulatory authorities are in part unpredictable and thus a souce of risk. Risk that derives from the unavoidable unpredictability of U.S. governments' actions can be central here.[12]

While flexibiliy to respond to changes in the market and technology is a necessary feature of successful program management, flexibility to the point of uncertainty can be its undoing. Due to the nature of the Congressional authorization-appropriation process, budget level uncertainty can never be completely eliminated. Recent budget cutting fervor in Washington is an all too painful reminder of this uncertainty. Another source of uncertainty is year-to-year changes in internal program budget allocation. In particular, the urge to throw money at individual firms or ideas which promise miraculous results without subjecting them to the same technical scrutiny or competition as the other alternative approaches should be strongly resisted. The process argued for in this chapter is one of predictability, with the option to accelerate or decelerate as events dictate. Once a fundamental philosophy and approach is determined, however, it should be followed. This is the essence of multi-year planning.

Should program uncertainty be so rampant as to adversely affect private investment decisions,[13] then it can easily be argued that

---

[12] Richard Schmalensee, Appropriate Government Policy Toward Commercialization of New Energy Supply Technologies, MIT Energy Lab. Working Paper 79-052WP, October 1979, pp. 44.

[13] Arguably, this was the situation faced by solar heating and cooling products with the uncertainty surrounding federal tax credits over the last several years. Of course, whether the solar tax credits were an appropriate commercialization tool to be employed at this time is another matter.

program imperfections have merely substituted for market imperfections with possibly negative results.

3. Political Constraints

One of the characteristics of U.S. governmental activities is that they consist of some mix of administrative and legislative actions, and technology development is certainly no exception to this. In particular, as program activities become publicly visible, either in the technology or engineering development phases, Congressional influence tends to turn from general program budget concerns to specific project design concerns. Often this concern for program content stems from what is considered to be inaction or lack of aggressiveness on the part of the administrative authority.[14] This multiple-authority management can be disastrous due to the often inappropriate timing of program activities and internal misallocation of program resources. Numerous examples also abound in nearly every technology class of premature pork-barrel demonstration projects, the failures of which either lead to costly overruns or damaged technological credibility or both. Most program managers seem to view these projects as an unfortunate but necessary evil to maintain public (i.e., Congressional) visibility.[15] Perhaps

---

[14]This is most certaintly the situation in the creation of FPUP (Federal Photovoltaic Utilization Program) where what was considered a void in DOE photovoltaic commercialization plans was filled by a program of congressional origin. Most analysts of photovoltaic commercialization viewed this program as poorly timed and of questionable design.

[15]In a totally serious discussion in Chapter V, "Implications for Congress" of the report by the Office of Technology Assessment, The Role of Demonstrations in Federal R&D Policy, 1978, p. 45, we find: "In contrast to their limited usefulness in the R&D framework, demonstrations are considered by many be to politically attractive. Demonstrations permit modestly priced responses to emerging political problems; they are, in a sense, a means of symbolic action. Demonstration projects can show constituents that Washington is doing something for them. Demonstration may be a means of delaying policy decisions while additional information--both technical and political--is accumulated. Demonstrations are a convenient point of compromise between those who would do much and those who would do little."

pork-barrel projects are unavoidable, but certain actions may help to minimize their frequency and impact. First, the elimination of perceived gaps in the program approach should serve to minimze the projects proposed to fill the gaps. We think our framework helps accomplish this. The everpresent political tendency to over-accelerate or eliminate technology development programs must be tempered with sound technical judgment, which does not always mean catering to "industry" wishes. Second, the explicit set-aside of a small amount of program resources for the purpose of funding unsolicited proposals or "innovative concepts" may serve as a tool to channel political pork-barrel proposals so that they may be evaluated against each other and the program in terms of timing and technical content, and thus, limited in size.

Other institutional factors may place contraints on program design and management as well. One manifestation of this constraint could be termed "inertia for technology losers." One of the major questions above concerned the decision to drop losing options. Complicating this decision is the tendency of program players to fight to retain support for their losing options. Political pressure can often be effectively applied even if all technical and economic judgment indicates that the organization's pet project is a clear loser. This applies to non-profit research organizations as well as private industry.[16] Solutions to this problem are not easy, but it clearly calls for regular and credible program assessment.

4. Organization Structure and Goal-Oriented Management

Several implications for program organization structure should be

---

[16]This problem is, of course, not unique to government sponsored R&D, but may be more prevalent there.

obvious from the previous discussions. First, the requirements of the suggested approach imply that the management of technology development cannot be separated from the management of engineering or market development activities.[17] Second, it is probably more desirable to structure the organization along the lines of our matrix elements, where clear tasks and roles vis-à-vis private industry can be assigned than to attmept to mimic a corporate organization structure.

A frequent criticism of commerialization programs is that they are either too "goal-oriented" or that they have no stated objectives ("technology sandboxes"). Certainly, effective management of technological change requires some kind of quantitative objectives or goals to guide decisions, but which kinds of goals are appropriate and which are not?

Numerical goals are fundamentally management tools. They function as yardsticks to measure technological progress and to continuously compare technology options.[18] To be useful in this respect, they must be easily communicated and flexible (recall that we have a moving target). Consider two examples of commonly used program goals: price and quantity.

Since we have argued that these programs should be directed at technology development to achieve cost reduction, price goals ($/kW,

---

[17]This condition existed within DOE for many years when separate Assistant Secretaries were responsible for Energy Technology and Conservation and Solar Applications. This structure has recently been modified.

[18]See U.S. Department of Energy, Federal Policies to Promote the Widespread Utilization of Photovoltaic Systems, Vol. II, Chapter 4 (prepared by the Jet Propulsion Laboratory, March 24, 1980) for a more complete discussion.

$/kWh, $/Btu, etc.) become the management mechanisms for the measurement of technological change. Quantity goals (BBls, quads, GW, etc.) are primarily the measures of successful diffusion into society. It was argued above that the program manager has a much more direct involvement in the process during the development phases than during market development activities by their very nature. Thus, from an internal management point of view price goals seem to be more direct measures of program success. Of course, price goal achievement also requires private sector capital investment and thus market volume, but to assess and compare technology options with respect to the price goals merely requires the tools to make consistent cost/price projections. Quantity goals, on the other hand, are much more subject to non-controllable actions in the market development phase, making their use from a management control point of view very clumsy.

The price goals structure employed in the development of the U.S photovoltaics program is considered by most observers to be the chief factor which contributed to this program's success prior to 1980. Unfortunately, the recent budget cutbacks were accompanied by the elimination of price goals as a program management tool for photovoltaics.

3.1 <u>Market Structure Concerns</u>

Since the concept we are presenting here relies on the government as a manager of activities which fundamentally are carried out in the private sector, it is important to consider the supply-side market structure. We have alluded above to vertical integration possibilities. The purpose of the following section is to draw some conclusions about the relevance of market structure concerns in program design and management.

Concern for market structure and supply-industry competition stems from basically two factors. The first is the impact of market structure on continued, further technological change in the industry. The second involves the ability to incorporate and realize the benefits of current technological change.

1. Market Structure and Technological Change

A very significant literature has been developed on the relationship between competition in industries and the rate of technological change.[19] We do not review this literature here other than to say that the results are quite inconclusive. Research shows a correlation between R&D intensity and high industry concentration, but is in unclear as to the direction of the cause and effect.[20]

While we cannot conclude that a competitive market structure is beneficial for future technolgical change, we may be able to conclude that due to the effects of market stucture on pricing, competitive structures may be vital to the realization of the benefits of technological change through price reduction.

Finally, economics aside, there is a substantial political sentiment which requires actions that ultimately promote the maintenance of highly competitive industries. This sentiment probably cannot be successfully dismissed.

Given the need to promote (or at least not inhibit) competition, the lack of a body of theory which adequately describes the relationship

---

[19]See Kamien and Schwartz, "Market Structure and Innovation: A Survey," Journal of Economic Literature, March 1975.

[20]See Scherer, F.M., Industrial Market Structure and Economic Performance, Rand McNally, Chicago, 1980, pp. 371-376.

between government policy and market structure (especially in the context of technological change) makes it difficult to prescribe appropriate government actions during the process of technology development to promote competition.

In the remainder of this part we look at some of the factors involved in anti-competitive market structures and some of the traditional tools used by the government to deal with them.

2. Anti-Competitive Factors

For the purposes of a brief discussion we separate the factors which traditionally are considered to be contributors to anti-competitive market structures into four areas: concentration, vertical integration, barriers to entry, and government policy.

Concentration. It is generally believed that the higher the concentration of a particular industry, as measured by one of many indices and ratios, the greater the degree of monopoly power which can be exercised by any particular firm. This may make some sense in theory, but is very difficult to discern in practice. The greatest problem may simply be the definition of the industry. The photovoltaics industry, for example, is composed of players from the oil industry, the semi-conductor industry, and the electrical service industry, to name a few. How does one measure concentration when the industry members cut across classifiable lines? Furthermore, concentration in a static, mature industry is fundamentally different from concentration in an emerging one. We certaintly have to be worried about the number and types of firms involved in developing and incorporating the new technology, but how many should there be and of what type?

Vertical Integration. Vertical integration involves the degree to which intermediate production materials and products are produced within a given corporate entity or "firm." A highly integrated photovoltaics firm, for example, would refine silicon, produce modules, fabricate systems and install them on roofs.

While vertical integration may be desirable in terms of reducing transaction costs and preventing monopoly price stalemates for the integrating firm, it may harm non-integrated firms by restricting sources of supply or markets. This problem could exist, for example, if the firms producing low-cost raw material silicon chose to dedicate their production to internal module manufacturing.

Barriers to Entry. Other factors contributing to anti-competitive market structure include such things as patents or secrecy; the need to commit large amounts of capital on entry; strong consumer preference favoring established products, etc. One not mentioned which is relevant to new technologies is the possible barrier associated with economies of scale in production. Scale economies may be quite beneficial in terms of realizing cost reduction through technology development, but the scale may be so large relative to market size that only a few very large firms can generate the captial and sustain (sell) the volume required. As an empirical matter, however, scale economies may not be all that important.

Government Policy. So as not to give the wrong impression, government regulation independent of program actions may serve as a significant contributor to non-competitive market structure. It will also become obvious that there are certain program actions which if poorly timed could have a serious anti-competitive effect (e.g., product standards).

3. Techniques Traditionally Available to Promote Competition

Despite the lack of an adequate theory, the techniques traditionally available to the government commercialization programs to promote competition are four-fold: competitive contracting; small business set-asides; multiple contract awards; and product standards.

Competitive contracting helps to insure complete consideration and comparison of all potential bidders' concepts, technologies and products, but is insufficient to insure that the industry is composed of many competing winners.

Small business set-asides insure that large established entities do not overwhelm small, potential entrants, but do not substantially mitigate many barriers to entry. Furthermore, if some scale economies are fundamental to cost-reduction and technological change, it is not inconceivable that the technological process is simply not feasible for small ventures and hence small business set-asides may prove detrimental to accelerated technological change.

Multiple contract awards serve to increase the number of players involved which must be a positive influence on competition, but they also increase program costs substantially. How many awards are appropriate for any given contract? Two, three, four?

Interchangeability brought about by product standards may serve to ease entry barriers. But if inappropriately timed such standards may inhibit innovation, resulting in a more severe deterrent to entry.

The prospects here look pretty bleak. The theory does not provide sufficient background to determine whether these actions are potentially good or bad. Compound this uncertainty with the dynamic characteristics of emerging industries, and the prospects for definitive answers to the market structure concerns in commercialization programs seem remote.

About all that we can do here is to call for more research into these factors.

4.C Conclusion

The economist needs to make an effort to operationalize his concept of market failures in the context of new technology development. Toward that end, we have examined the question of the appropriate governmental role and found it to contain two questions: whether the government should be involved in a technology-specific way, and if it should, how should it design its program for involvement. While most analysis to date has focused solely upon the first question, we offer some perspective on the second. Further, we have developed some concepts for decomposing a technology development activity into subsidiary activities and developed a method for questioning the appropriateness of governmental involvement for each of the subsidiary activities. We have demonstrated the use of these concepts with a matrix and shown how it could be used with an example technology (photovoltaics). Finally, while we raise the issue of measuring the significance of market failures, we do not answer it, but merely point out its importance.

Chapter 8

Working Papers and Technical Reports

Number	REPORTS
NONE	Smith, Douglas. PHOTOVOLTAIC POWER IN LESS DEVELOPED COUNTRIES (March 1977)
77-020	Goldman, N. PHOTOVOLTAIC DECISION ANALYSIS (October 1977)
77-021	Linden L., et al. THE SOLAR PHOTOVOLTAICS INDUSTRY: THE STATUS AND EVOLUTION OF THE TECHNOLOGY AND THE INSTITUTIONS (December 1977)
78-003	Hartman, R. A CRITICAL REVIEW OF SINGLE FUEL AND INTERFUEL SUBSTITUTION RESIDENTIAL ENERGY DEMAND MODELS (March 1978)
78-004	Lilien, G. THE DIFFUSION OF PHOTOVOLTAICS: BACKGROUND MODELING AND INITIAL REACTION OF THE AGRICULTURAL-IRRIGATION SECTOR (March 1978)
78-006	Smith, D. and S. Allison. MICRO IRRIGATION WITH PHOTOVOLTAICS (April 1978)
78-007	Carpenter, P. and G. Taylor. AN ECONOMIC ANALYSIS OF GRID-CONNECTED RESIDENTIAL SOLAR PHOTOVOLTAIC POWER SYSTEMS (May 1978)
78-008	Weitzman, M. OPTIMAL SEARCH FOR THE BEST ALTERNATIVE (May 1978)
78-010	Carpenter, P. and R. Tabors. A UNIFORM VALUATION METHODOLOGY FOR SOLAR PHOTOVOLTAIC APPLICATIONS COMPETING IN A UTILITY ENVIRONMENT (June 1978)
78-013	Energy Laboratory in association with the Sloan School and Department of Urban Studies and Planning. THE CONDITIONAL/GENERALIZED MAXIMUM LIKELIHOOD LOGIT COMPUTER PROGRAM: INSTRUCTIONS FOR USE (June 1978)
78-019	Lilien, G. THE DIFFUSION OF PHOTOVOLTAICS: BACKGROUND MODELING CALIBRATION AND IMPLICATIONS FOR GOVERNMENT POLICY (May 1978)
78-020	Nutt-Powell, T. et al. TOWARD A THEORY OF INSTITUTIONAL ANALYSIS (April 1978)
78-032	Tabors, R. et al. SERI PHOTOVOLTAIC VENTURE ANALYSIS: LONG-TERM DEMAND ESTIMATION (June 1978)
78-033	Photovoltaics Group. PLANNING AND ANALYSIS FOR DEVELOPMENT AND COMMERCIALIZATION OF PHOTOVOLTAIC ENERGY CONVERSION SYSTEMS-FINAL REPORT (July 1978)
78-034	Tabors R. and P. Carpenter. METHODOLOGIES AND DEFINITONS OF SOLAR PHOTOVOLTAIC PLANNING REGIONS (July 1978)

78-036 Braid, R. THE DEVELOPMENT & CRITICAL REVIEW OF ANNUAL STOCK AND GROSS INVESTMENT FOR RESIDENTIAL ENERGY-USING CAPITAL (June 1978)

78-039 F. Pickel. COGENERATION IN THE U.S.: AN ECONOMIC AND TECHNICAL ANALYSIS (November 1978)

78-040 Nutt-Powell, B. and Sorrell, L. A SIMULTANEOUS PREFERENCE REPORTING METHODOLOGY APPLIED TO THE NEBRASKA AGRICULTURAL COMMUNITY (October 1978)

79-005 Lilien, G. and S. McCormick. THE CONSUMER RESPONSE TO PHOTOVOLTAICS: THE MIT SUN DAY EXPERIENCE (February 1979)

79-006 Finger, S. ELECTRIC POWER SYSTEM PRODUCTION COSTING AND RELIABILITY ANALYSIS INCLUDING HYDRO-ELECTRIC, STORAGE, AND TIME DEPENDENT POWER PLANTS (February 1979)

79-007 Sorrell, L. and Nutt-Powell, B. SUN DAY: A SECOND APPLICATION OF A SIMULTANEOUS PREFERENCE REPORTING METHODOLOGY (January 1979)

79-009 Roberts, K and M. Weitzman. FUNDING CRITERIA FOR RESEARCH DEVELOPMENT, AND EXPLORATION PROJECTS (April 1979)

79-011 Tabors, R. THE ECONOMICS OF WATER LIFTING FOR SMALL SCALE IRRIGATION IN THE THIRD WORLD: TRADITIONAL AND PHOTOVOLTAIC TECHNOLOGIES (May 1979)

79-016 Dinwoodie, T. A PHOTOVOLTAIC ASSISTED RESIDENCE WITH SUPPLEMENTAL BATTERY STORAGE: SEARCHING FOR COMPLEMENTARITY

79-020 Finger, S. SYSGEN, PRODUCTION COSTING AND RELIABILITY MODEL USER DOCUMENTATION (July 1979)

79-021 Pine, G. ASSESSMENT OF INTEGRATED URBAN ENERGY OPTIONS (February 1979)

79-024 The Homeostatic Control Group. Proceedings of a Conference held in Boxborough, Mass., May 30-June 1, 1979. NEW ELECTRIC UTILITY MANAGEMENT AND CONTROL SYSTEMS. (July 1979)

79-025 Finger, S. ELECTRA, TIME DEPENDENT POWER GENERATION OPERATION MODEL USER DOCUMENTATION (August 1979)

79-026 Neff, T. SOCIAL COST FACTORS AND THE DEVELOPMENT OF PHOTOVOLTAIC ENERGY SYSTEMS (October 1979)

79-029 Nutt-Powell, T., et al. RESEARCH DESIGN FOR INSTITUTIONAL ANALYSIS OF HUD'S SOLAR HEATING AND COOLING DEMONSTRATION PROGRAM (May 1979)

79-030 Nutt-Powell, T., et al. SOLAR HEATING AND COOLING OF HOUSING: FIVE INSTITUTIONAL ANALYSIS CASE STUDIES (June 1979)

79-031 Nutt-Powell, T. and J. Wagner. INSTITUTIONAL ANALYSIS OF THE ACCEPTANCE OF PHOTOVOLTAICS IN DAYTIME RADIO BROADCASTING (June 1979)

79-032 Russo, G. SOLAR ENERGY CONVERSION SYSTEMS ENGINEERING AND ECONOMICS ANALYSIS - INPUT DEFINITION (Vol. I) (November 1979)

79-033 Russo, G. SOLAR ENERGY CONVERSION SYSTEMS ENGINEERING AND ECONOMICS ANALYSIS - INPUT DEFINITION (Vol. II) (November 1979)

79-042 Ellis, P. THE AVAILABILITY OF CAPITAL FOR DEVELOPING PHOTO-VOLTAIC MARKETS (November 1979)

79-043 Bottaro, D. STANDARDS, WARRANTIES AND COMMERCIALIZATION OF NEW ENERGY TECHNOLOGIES (November 1979)

79-044 Nutt-Powell, T. INSTITUTIONAL ANALYSIS OF SOLAR HEATING AND COOLING OF HOUSING: SUMMARY REPORT (September 1979)

79-045 Nutt-Powell, T. and J. Wagner. SOLAR HEATING AND COOLING STANDARD SETTING: AN INSTITUTIONAL ANALYSIS CASE STUDY (August 1979)

79-048 Nutt-Powell, T. and S. Landers. CENTER PIVOT IRRIGATION IN NEBRASKA: AN INSTITUTIONAL ANALYSIS CASE STUDY (December 1979)

80-002 Dinwoodie, T. FLYWHEEL STORAGE FOR PHOTOVOLTAICS: AN ECONOMIC EVALUATION OF TWO APPLICATIONS (February 1980)

80-007 Nutt-Powell, T. and L. Sorrell. PHOTOVOLTAICS AND THE NATIONAL PARK SERVICE: AN INSTITUTIONAL ANALYSIS (April 1980)

80-008 Cox, Alan J. THE ECONOMICS OF PHOTOVOLTAICS IN THE COMMERCIAL, INSTITUTIONAL AND INDUSTRIAL SECTORS (April 1980)

80-020 Utility Systems Program, MIT Energy Laboratory, Stone & Webster Engineering and Putnam, Hayes & Bartlett. ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM (June 1980)

80-022 Dinwoodie, T. OESYS: A SIMULATION TOOL FOR NON-CONVENTIONAL ENERGY APPLICATION ANALYSIS (August 1980)

80-023 Nutt-Powell, T. and M. Furlong. MOBILE-COMPONENT HOUSING AND SOLAR ENERGY: THE POSSIBILITIES (April 1980)

80-024 Nutt-Powell, T. AN INSTITUTIONAL ANALYSIS OF THE SOLAR HEATING AND COOLING RESIDENTIAL DEMONSTRATION PROGRAM (April 1980)

80-025 Dinwoodie, T. and A. Cox. THE IMPACT ON PHOTOVOLTAIC WORTH OF UTILITY RATE AND REFORM AND OF SPECIFIC MARKET, FINANCIAL, AND POLICY VARIABLES (September 1980)

80-028 Dinwoodie, T. and J. Kavanaugh. COST GOALS FOR A RESIDENTIAL PHOTOVOLTAIC/THERMAL LIQUID COLLECTOR SYSTEM SET IN THREE NORTHERN LOCATIONS (October 1980)

81-004 Fuller, F., Gary Lilien, Martin Wulfe. PV1 MODEL VERIFICATION AND VALIDATION (January 1981)

81-006 Pickel, F. ELECTRIC UTILITY FORECASTING OF CUSTOMER COGENERATION AND THE INFLUENCE OF SPECIAL RATES (March 1981)

NONE MIT Energy Laboratory, Stone & Webster, PHB. ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM; A PROGRESS REPORT ON RPI1529 (May 1980)

81-011 Finger, S. INTEGRATION OF DECENTRALIZED GENERATORS WITH THE ELECTRIC POWER GRID (April 1981)

81-012 Lilien, G. and Frank Fuller. THE PV MARKET ANALYSIS PROGRAM: BACKGROUND, MODEL DEVELOPMENT, APPLICATIONS AND EXTENSIONS (April 1981)

81-022 Klosowicz, P. A FINANCIAL/REGULATORY MODEL FOR UTILITY CAPACITY EXPANSION PLAN EVALUATION (June 1981)

81-027 Bottaro, D., Alan Cox and Nancy Wheatley. THE ECONOMIC IMPACT OF STATE ORDERED AVOIDED COST RATES FOR PHOTOVOLTAIC GENERATED ELECTRICITY (July 1981)

81-028 Tabors, R. HOMEOSTATIC CONTROL: ECONOMIC INTEGRATION OF SOLAR TECHNOLOGIES INTO ELECTRIC POWER OPERATIONS AND PLANNING (July 1981)

81-033 Schweppe, F., Richard Tabors and James Kirtley. HOMEOSTATIC CONTROL: THE UTILITY/CUSTOMER MARKETPLACE FOR ELECTRIC POWER (September 1981)

81-040 Lilien, G. MARKET DIFFUSION AND THE EFFECT OF DEMONSTRATIONS: A STUDY OF THE DENVER METRO PASSIVE SOLAR HOME PROGRAM (October 1981)

81-041 Bottaro, D. and Paul Carpenter. PERSPECTIVES ON THE GOVERNMENT ROLE IN NEW TECHNOLOGY DEVELOPMENT AND DIFFUSION (November 1981 revised December 1981)

81-048 Wulfe, M. PV1: AN INTERACTIVE COMPUTER MODEL TO SUPPORT COMMERCIALIZATION POLICY FOR PHOTOVOLTAICS POLICY ANALYSIS (June 1981)

82-003 Bohn, R., Richard D. Tabors, Bennett Golub and Fred Schweppe. DEREGULATING THE ELECTRIC UTILITY INDUSTRY (January 1982)

82-004 Dinwoodie, T. RESIDENTIAL PHOTOVOLTAIC WORTH: AN ASSESSMENT OF RETROFIT VS: NEW CONSTRUCTION (January 1982)

82-005 Dinwoodie, T. RESIDENTIAL PHOTOVOLTAIC WORTH: A SUMMARY ASSESSMENT OF THE MIT ENERGY LABORATORY (January 1982)

WORKING PAPERS

MIT-EL#

77-025WP Smith, D. SMALL SCALE ENERGY ACTIVITIES IN INDIA AND BANGLADESH - TRIP REPORTS - MARCH 17-31 AND APRIL 3-14, 1977 (August 1977)

77-030WP Carpenter, P. and G. Taylor. THE ECONOMICS AND REGULATION OF USER-OWNED PHOTOVOLTAIC SYSTEMS: A PRELIMINARY ANALYSIS (September 1977)

77-037WP Hartman, R. AN OLIGOPOLISTIC PRICING MODEL OF THE U.S. COPPER INDUSTRY: A PROBABILITY MODEL APPROACH (October 1977)

78-006WP Tabors, R. PHOTOVOLTAIC POWER SYSTEMS: REVIEW OF CURRENT MARKET STUDIES: METHODOLOGY FOR LONG TERM DEMAND PROJECTION (May 1978)

78-023WP Bottaro, D. THE PURPOSE AND ROLE OF PRODUCT STANDARDS IN THE COMMERCIALIZATION OF NEW ENERGY TECHNOLOGIES: A PRELIMINARY ANALYSIS (October 1978)

78-031WP Werth, A. RESIDENTIAL DEMAND FOR ELECTRICITY AND GAS IN THE SHORT RUN: AN ECONOMETRIC ANALYSIS (June 1978)

79-002WP Siczewicz, P. and T. Nutt-Powell. INSTITUTIONAL ANALYSIS OF THE NATIONAL PARK SERVICE: A PRELIMINARY EXPLORATION (January 1979)

79-009WP Helliwell, J. and A. Cox. SIMULATION ANALYSIS OF ENERGY PRODUCTION IN THE B.C. PULP AND PAPER INDUSTRY (February 1979)

79-010WP Hartman, R. A GENERALIZED LOGIT FORMULATION OF INDIVIDUAL CHOICE (February 1979)

79-013WP Hendrickson, E. and Nutt-Powell, T. INSTITUTIONAL ANALYSIS OF DAYTIME RADIO: AN OVERVIEW OF THE BROADCAST INDUSTRY (January 1979)

79-014WP McDaniel, P. and Nutt-Powell, T. INSTITUTIONAL ANALYSIS OF GOVERNMENTAL INVOLVEMENT IN HOUSING: A PRELIMINARY EXPLORATION (January 1979)

79-015WP Furlong, M. and Nutt-Powell, T. INSTITUTIONAL ANALYSIS OF RESEARCH AND SOCIALIZATION IN HOUSING: A PRELIMINARY EXPLORATION (March 1979)

79-016WP Swetky C. and Nutt-Powell, T. INSTITUTIONAL ANALYSIS OF HOUSING PRODUCTION: A PRELIMINARY EXPLORATION (March 1979)

79-017WP Hartman, R. FRONTIERS IN ENERGY DEMAND MODELING (April 1979)

79-018WP Hartman, R. and A. Werth. SHORT-RUN RESIDENTIAL DEMAND FOR FUELS: A DISAGGREGATED APPROACH

79-019WP Parker, B. and T. Nutt-Powell. INSTITUTIONAL ANALYSIS OF STANDARD SETTING IN THE UNITED STATES: A PRELIMINARY EXPLORATION (February 1979)

79-020WP Reamer, A., S. Heim and T. Nutt-Powell. INSTITUTIONAL ANALYSIS OF ENERGY PROVISION IN HOUSING: A PRELIMINARY EXPLORATION (February 1979)

79-025WP Hartman, R. SOME EVIDENCE ON DIFFERENTIAL INVENTORY BEHAVIOR IN COMPETITIVE AND NON-COMPETITIVE MARKET SETTINGS (April 1979)

79-026WP McCleary, J. PHOTOVOLTAIC TECHNOLOGY: A REVIEW (May 1979)

79-032WP Tabors, R. APPLICATION OF SECTOR- AND LOCATION-SPECIFIC MODELS OF THE "WORTH" OF RENEWABLE ENERGY (June 1979)

79-038WP MIT Energy Laboratory. SUMMARY: PHOTOVOLTAIC INTERNATIONAL PLAN MEETING (July 1979)

79-039WP Lilien, G. PHOTOVOLTAICS: MARKET RESPONSE AND IMPLICATIONS FOR GOVERNMENT POLICY (June 1979)

79-040WP Bradley, P. PRODUCTION OF DEPLETING RESOURCES: A COST-CURVE APPROACH (June 1979)

79-041WP Hartman, R. A MODEL OF RESIDENTIAL ENERGY DEMAND (August 1979)

79-042WP McCormick, T. USER'S GUIDE TO THE OAK RIDGE NATIONAL LABORATORY RESIDENTIAL ENERGY DEMAND MODEL (August 1979)

79-044WP Klein, T. PHOTOVOLTAICS IN THE THIRD WORLD: PRIORITIES OF CONSUMING COUNTRIES CONCERNING COMMERCIALIZATION (August 1979)

79-045WP Smith, D. PHOTOVOLTAICS IN THE THIRD WORLD (August 1979)

79-047WP MIT Residential Energy Demand Group. AGGREGATE POOLED DATA UTILIZED AND/OR DEVELOPED FOR RESIDENTIAL ENERGY DEMAND (August 1979)

79-049WP Hartman, R. DISCRETE CONSUMER CHOICE AMONG ALTERNATIVE FUELS AND TECHNOLOGIES FOR RESIDENTIAL ENERGY USING APPLIANCES (Revised December 1979)

79-050WP Law, S. and D. Bottaro. INSTITUTIONAL ISSUES ASSOCIATED WITH RESIDENTIAL PV APPLICATIONS: A BIBLIOGRAPHY (October 1979)

79-054WP Kalish, S. and G. Lilien. MODELS OF NEW PRODUCT DIFFUSION: CURRENT STATUS AND RESEARCH AGENDA (October 1979)

79-059WP Saltzman, D. THE DEVELOPMENT OF CAPITAL COST AND EFFICIENCY DATA FOR RESIDENTIAL ENERGY-USING EQUIPMENT (October 1979)

79-064WP Bottaro, D. COMMENTS ON PROPOSED RULEMAKING CONCERNING ELECTRIC RATES FOR SOLAR USERS (December 1979)

79-066WP Nutt-Powell, T. and S. Landers. CENTER PIVOT IRRIGATION IN NEBRASKA: AN INSTITUTIONAL ANALYSIS CASE STUDY (December 1979)

79-070WP Cox, A.J. THE USE OF WOOD WASTE FOR COGENERATION IN BRITISH COLUMBIA'S PULP AND PAPER INDUSTRY (April 1979)

80-007WP Wheatley, N. SOFT COSTS ASSOCIATED WITH THE SALE OF PHOTOVOLTAIC SYSTEMS FOR RESIDENTIAL APPLICATIONS (February 1980)

80-009WP Wheatley, N. DISTRIBUTION CHANNELS FOR RESIDENTIAL PHOTO-VOLTAIC SYSTEMS (March 1980)

80-011WP Parker, B. INSTITUTIONS AND SOLAR THERMAL ACCEPTANCE: THE CASES OF 924 WEST END AVENUE AND CATHEDRAL SQUARE (April 1980)

80-014WP Hartman, R. THE INCORPORATION OF SOLAR PHOTOVOLTAICS INTO A MODEL OF RESIDENTIAL ENERGY DEMAND (May 1980)

80-015WP Hartman, R. AN ANALYSIS OF DEPARTMENT OF ENERGY RESIDENTIAL APPLIANCE EFFICIENCY STANDARDS (May 1980)

80-016WP Bohn, R. INDUSTRIAL RESPONSE TO SPOT ELECTRICITY PRICES: SOME EMPIRICAL EVIDENCE (February 1980)

80-017WP Wizon, A. THE MRI DATA RETRIEVAL SYSTEM (June 1980)

80-018WP Hartman, R. A NOTE ON THE USE OF AGGREGATE CHOICE IN INDIVIDUAL CHOICE MODELS: DISCRETE CONSUMER CHOICE AMONG ALTERNATIVE FUELS FOR RESIDENTIAL APPLIANCES (July 1980)

80-034WP Neslin, S.A., G. Assmus and G. Lilien CONSUMER RESPONSE TO UNCERTAIN INFORMATION: COMMUNICATING THE FINANCIAL MERITS OF SOLAR ENERGY (September 1980)

80-041WP Kalish, Shlomo, G. Lilien OPTIMAL PRICE SUBSIDY POLICY FOR ACCELERATING THE DIFFUSION OF INNOVATION (October 1980)

81-001WP Bohn, Roger A THEORETICAL ANALYSIS OF CUSTOMER RESPONSE TO RAPIDLY CHANGING ELECTRICITY PRICES (August 1980, revised January 1981)

81-007WP Hartman, Raymond S. THE ESTIMATION OF HOUSEHOLD ENERGY DEMAND USING POOLED AGGREGATE DATA (March 1981)

81-008WP Bohn, Roger E., M. Caramanis and F.C. Schweppe. OPTIMAL SPOT PRICING OF ELECTRICITY: THEORY (March 1981)

81-010WP Litterman, M. ALTERNATIVE METHODS FOR MAXIMUM LIKELIHOOD ESTIMATION: DESCRIPTION AND COMPUTER IMPLEMENTATION (March 1981)

81-012WP MIT Energy Lab, Stone & Webster. ELECTRIC GENERATION EXPANSION ANALYSIS SYSTEM (EGEAS) A Progress Report on RPI 1529 (February 1981)

81-014WP Cox, A.J. THE ECONOMICS AND REGULATION OF DISTRIBUTED POWER SYSTEMS IN THE UTILITY GRID: PHOTOVOLTAICS (April 1981)

81-015WP Dudley, K. SOLAR POWERED DESALINATION IN EGYPT: A DESIGN AND COST ANALYSIS (March 1981)

81-019WP Keane, M. DEPARTMENT OF ENERGY APPLIANCE EFFICIENCY TESTING PROCEDURES AND DEFINITIONS (May 1981)