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MISSION ANALYSIS OF PHOTOVOLTAIC SOLAR ENERGY CONVERSION
VOLUME 1

Executive Summary

By
S. L. Leonard
E. J. Rattin
B. Siegel

December 1977
(TIC Issuance Date)

Work Performed Under Contract No. EY-76-C-03-1101

The Aerospace Corporation
Energy and Transportation Division
El Segundo, California

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Solar Energy

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Volume I

Executive Summary

S. L. Leonard, E. J. Rattin, and B. Siegel

Energy and Transportation Division
THE AEROSPACE CORPORATION
El Segundo, California

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FOREWORD

This document constitutes the first volume of a four-volume final report on a study carried out under Contract No. EY76-C-03-1101, Project Agreement 8, "Mission Analysis of Photovoltaic Solar Energy Systems," for the Division of Solar Energy of the U.S. Energy Research and Development Administration. This volume provides an overview of the entire project. The other volumes in the report are: Volume II, Survey of Near-Term (1976-1985) Civilian Applications in the United States; Volume III, Major Missions for the Mid-Term (1986-2000); and Volume IV, Supplementary Studies.

The study was conducted by the Energy Systems Group of the Energy and Transportation Division of The Aerospace Corporation. Dr. Leonard Magid, Acting Chief of the Silicon Technology Programs Branch, was the ERDA Program Manager for this contract, and Dr. A.B. Greenberg, General Manager of the Energy and Transportation Division, was the Principal Investigator. Dr. M.B. Watson is the

Director of the Energy Systems Group, and Dr. S.L. Leonard, Director, Photovoltaic Projects, provided the program management.

This volume was prepared by Dr. S.L. Leonard, E.J. Rattin, and B. Siegel.

The authors wish to express appreciation for the support of the project by a number of other personnel of The Aerospace Corporation. These include R.C. Anthony, Dr. P. Breisacher, W.E. Ellis, S.L. Larkin, G.J. Mead, Dr. P.K. Munjal, J.A. Neiss, P.L. Merryman, Dr. C.M. Randall, H. Wong, and H.H. Yoshikawa. In addition, Dr. R.J. Lutz, Assistant Professor of Marketing, University of California at Los Angeles, provided valuable advice in the field of market research. The help of J.E. Hallett in overseeing the production of the report is also gratefully acknowledged.

ABSTRACT

This volume is a summary report of an investigation of terrestrial applications for the photovoltaic conversion of solar energy. The specific objectives of the study were: (a) to survey and evaluate near-term (1976-1985) civilian photovoltaic applications in the United States; (b) to evaluate the most promising major missions for the mid-term period (1986-2000) and to determine the conditions under which photovoltaic technology can compete in those applications at array prices consistent with ERDA goals; (c) to address critical external issues and identify the sensitivity of photovoltaic system technical requirements to such factors; and (d) to quantify the societal costs of alternative energy sources and identify equalizing incentives.

The study was divided into six separate but interrelated tasks: Task 1, Analysis of Near-Term Applications; Task 2, Analysis of Major Mid-Term Missions; Task 3, Review and Updating of the ERDA Technology Implementation Plan; Task 4, Critical External Issues; Task 5, The Impact of Incentives; and Task 6, The Societal Costs of Conventional Power Generation. The emphasis of the study was on the first two of these tasks, the other four serving to provide supplementary information.

Under Task 1, a survey was made of current and potential applications in which photovoltaic technology can be competitive at array prices between \$15/W_{pk} (the current price), and ~\$1/W_{pk} (the ERDA 1984 price goal). Only non-military U.S. applications were identified. For 21 of the 50, sufficient data were available to permit a quantitative estimate of the size of the potential market. It was estimated (albeit without making a detailed market penetration analysis) that cumulative array sales, through 1985, for these 21 groups of applications would amount to about 62 MW_{pk} and that annual sales would reach ~13 MW_{pk}/year in 1985. If the average size of the markets associated with the other 29 promising groups of applications is comparable to the average for the 21 quantified cases,

the total non-military U.S. market could exceed 25 MW_{pk}/year by 1985. Foreign markets and U.S. military markets should add significantly to this total.

The Task 2 effort represents an extension of work carried out in a previous investigation (Ref. 1), in which emphasis was on the development of methods for the technical and economic evaluation of major photovoltaic missions (i. e., those that represent really large potential markets) and on the application of this methodology in the evaluation of illustrative examples of some candidate missions (central station power plants and on-site residential applications) in the southwestern U. S. in the 1980-2000 period. The primary focus of the work in the current study was on central station power plant applications. Detailed technical and economic analyses were carried out in order to evaluate the effect on the economic competitive position of photovoltaic power plants of projected fuel prices and fuel price escalation rates, of geographic location, and of collector/concentrator type.

The results of these analyses were used in the development of a generalized analysis procedure permitting quick determination of the maximum allowable cost of the area-related elements of the system for various values of array efficiency and of average collected isolation. Because these investigations strongly suggest that it will be difficult for photovoltaic central station power plants using concentrators to produce electricity at a competitive price if only photovoltaic electricity is generated, a preliminary study was also made of a high concentration system in which profitable use is made of the thermal energy that is also collected.

The major conclusions derived from the study of central station applications are:

1. Photovoltaic power plants with flat-plate silicon arrays are likely to be economically competitive with coal-fired intermediate load plants by about 1990 in U. S. sunbelt locations (and perhaps as far north as Washington, D. C.)

provided that array costs can be brought down to the \$100-200/kW_{pk} range.

2. High-concentration (500-1000 concentration ratio) photovoltaic plants using collectors in the central receiver configuration and AlGaAs/GaAs arrays are also likely to be competitive with coal-fired plants, at least in the Southwest, if profitable use can be made of the thermal energy that is removed in cooling the arrays. If this thermal energy can either be sold directly (a net revenue of \$2/10⁶ Btu, above the cost of distribution and storage, appears feasible in many locations) or used to generate additional electricity in a low-pressure turbine, such systems may be able to produce electricity at a cost comparable to that of the energy generated in a flat-plate system when the array price is \$100/kW_{pk}. Even if no economic benefit is derived from the thermal energy, however, the energy cost would be about the same as that of electricity generated in a flat-plate photovoltaic plant when the array price is about \$370/kW_{pk}.
3. When the cost of electric storage (present value cost for 30 years of service, including replacement batteries) is \$40/kWh or more, photovoltaic plants without storage can provide electricity at lower cost than can systems with storage, even when the additional costs for conventional backup are included in the analysis.
4. The array price at which flat-plate photovoltaic power plants are economically competitive with coal-fired plants is very sensitive to array efficiency, to plant location, and to future coal prices and escalation rates. The figures given below are representative values of the allowable array price at two locations and for three fuel price scenarios (and for an array efficiency, at 20°C, of 13.5%).

Allowable Array Price Flat-Plate Photovoltaic Plant Without Storage

Location	1990 Coal Price (1975\$), \$/10 ⁶ Btu	Post-1990 Annual Fuel Price Escalation Rate	Allowable Array Price, \$/kW _{pk}
Inyokern, CA	0.75	0.05	75
	1.25	0.06	175
	1.75	0.07	305
Sterling, VA (Near Wash. D. C.)	0.75	0.05	25
	1.25	0.06	105
	1.75	0.07	205

These results are based on the assumption that the photovoltaic plant is constructed by an investor-owned utility company. Future studies might consider other forms of ownership, e. g., by a cooperative, that might result in higher allowable array prices.

The earlier work on on-site residential applications (Ref. 1) was also extended in the current study by a brief investigation of the impact of alternative ownership options (specifically, homeowner ownership versus utility ownership). The results of this investigation indicated that for an all-electric home in the Phoenix, Arizona, area the break-even array price (the array price at which the use of the photovoltaic system is competitive with conventional power) is in the range of \$250-600/kW_{pk} when the system is owned by the homeowner. When the photovoltaic system is owned by a private utility company, the break-even array price is in the \$100-300/kW_{pk} range, largely because the utility company must pay dividends on equity capital and income taxes on revenues generated to pay dividends.

As the final project activity under Task 2, a start was made on a study of applications for photovoltaic total energy systems (PTES), i. e., systems that provide both photovoltaic electricity and solar thermal energy to meet the combined demand for electrical and thermal energy at a single load point or a group of related load points. A survey of possible industrial PTES

applications revealed that a very large amount (~7 Q/year) of industrial process heat is used at temperatures below 180°C, a level that could easily be reached by a PTES system incorporating a concentrator and AlGaAs/GaAs solar cells. The PTES study also included a preliminary study of single-family residential applications in the Southwest. This study indicated that it may not be desirable to provide all of the required electrical and thermal energy by the PTES system, inasmuch as the minimum total cost of service is achieved when ~20% of the total energy requirement is provided by conventional sources.

Project activity under Task 3 was devoted largely to providing direct support to the special ERDA Photovoltaic Program Planning Group (PPG). The work of the PPG involved the joint efforts of individuals from a number of organizations and has been reported separately. It is therefore not discussed in this report.

Under Task 4, a study was made of the potential hazards to the environment, and to the health and safety of production workers and the general public, of greatly expanded photovoltaic array production and deployment. It was concluded that all of the identified hazards could be controlled by standard chemical industry procedures, with the possible exception of that associated with the release of toxic cadmium compounds when a CdS/Cu₂S array is burned up in a building fire.

Under Task 5, a study was made of the effect of a limited number of incentive strategies on the economics of photovoltaic power plant operation. Of the incentives considered, only those that led to an increase in the debt/equity ratio (at the same or lower rates of return on those sources of capital) resulted in significant decreases in the busbar energy cost, implying that federal loan guarantees might be the most effective way of improving the competitive position of photovoltaic power plants.

Under Task 6, an investigation was made of the non-internalized (i. e. , not reflected in the price of electricity) costs to society of coal-fired electric power generation. All elements of the production cycle, from coal mining to the release of effluents by the power plant, were considered, and the total of such non-internalized costs was estimated as about 5 mills (in 1975 dollars) for every kWh of electricity produced, provided that there is general compliance with the Federal Coal Health and Safety Act and with the New Source Performance Standards of the Clean Air Act.

Principal Conclusions/Recommendations

- MARKET FOR PHOTOVOLTAIC ARRAYS IN NEAR-TERM U. S. CIVILIAN APPLICATIONS COULD EXCEED 24 MW_{pk}/year BY 1985
RECOMMENDATIONS -
 - SURVEY U. S. MILITARY AND FOREIGN MARKETS (especially less developed countries)
 - ESTABLISH STANDARDS FOR PERFORMANCE AND SERVICE LIFE OF ARRAYS AND OTHER CRITICAL SUB-SYSTEMS TO FOSTER USER ACCEPTANCE
- FLAT-PLATE PHOTOVOLTAIC POWER PLANTS WILL BE COST-COMPETITIVE IN U. S. SUNBELT IN 1986-2000 PERIOD AT ARRAY PRICES IN \$100-200/kW_{pk} RANGE; PLANTS WITH CONCENTRATING COLLECTORS ARE ALSO ATTRACTIVE IF PROFITABLE USE CAN BE MADE OF THERMAL ENERGY
RECOMMENDATIONS -
 - MAINTAIN PROGRAM THRUST TOWARD ARRAY TECHNOLOGIES (e.g., thin film) WITH POTENTIAL TO REACH \$100-200/kW_{pk} PRICES
 - INCLUDE HIGH-CONCENTRATION SYSTEMS WITH USE OF THERMAL ENERGY AS PROGRAM OPTION
- BREAK-EVEN ARRAY PRICES FOR ON-SITE RESIDENTIAL PHOTOVOLTAIC SYSTEMS ARE \$250-600/kW_{pk} IF SYSTEM IS OWNED BY HOMEOWNER, \$100-300/kW_{pk} IF OWNED BY UTILITY
RECOMMENDATIONS -
 - INVESTIGATE INCENTIVE STRATEGIES FOR USER-OWNED ON-SITE SYSTEMS
 - EXPLORE POTENTIAL OF NON-RESIDENTIAL (industrial/commercial/institutional) USER-OWNED ON-SITE APPLICATIONS
- THERE IS A SUBSTANTIAL POTENTIAL MARKET FOR PHOTOVOLTAIC TOTAL ENERGY SYSTEMS (PTES) SUPPLYING INDUSTRIAL PROCESS HEAT AT TEMPERATURES OF UP TO 180°C
RECOMMENDATIONS -
 - ENCOURAGE DEVELOPMENT OF ARRAYS CAPABLE OF LONG LIFE AT 200°C OR ABOVE
 - IDENTIFY PREFERRED INDUSTRIAL PTES APPLICATIONS; CONDUCT SYSTEMS ANALYSES AND CONCEPTUAL DESIGN STUDIES
 - EXPLORE OTHER PTES MARKETS (residential, commercial, institutional, agricultural)

CONTENTS

ABSTRACT	v
I. INTRODUCTION	1
II. TASK 1. ANALYSIS OF NEAR-TERM MISSIONS	7
III. TASK 2. ANALYSIS OF MAJOR MID-TERM MISSIONS	29
IV. TASKS 3-6. SUPPLEMENTARY STUDIES	95
V. RESULTS, CONCLUSIONS, AND RECOMMENDATIONS	113
VI. REFERENCES	120

I. INTRODUCTION

This section contains discussions of the basic objectives of the project and of its organizational structure.

PHOTOVOLTAIC MISSION ANALYSIS: OBJECTIVES

The study discussed in this report was designed to provide ongoing support to the Energy Research and Development Administration (ERDA) in its program to develop photovoltaic conversion of solar energy as an alternative method for meeting a significant portion of the nation's energy needs. In Chart 1 are listed the overall objective of the project and the specific objectives that were identified in the course of organizing the project to reach the overall goal.

Although this project has been, in some respects, a continuation of an earlier study carried out under National Science Foundation (NSF) sponsorship (Ref. 1), the objectives listed in Chart 1 reflect a considerable shift in emphasis, in response to the changing requirements of the national program. The main objective of the earlier NSF study was to develop methods for the technical and economic evaluation of terrestrial photovoltaic missions (applications) that represent really large potential markets. This methodology was then applied in the evaluation of illustrative examples of some candidate missions (central station power plants and on-site residential applications) in the southwestern U.S. in the 1980-2000 period. A conservative approach was adopted in which photovoltaic solar energy conversion was treated, without favoritism, as a competitor in an energy marketplace that is characterized by high standards of service reliability and, in some instances, indirect subsidies for more conventional power generation methods.

One of the principal foci of the current study, by contrast, has been on the identification and technical/economic analysis of applications in which photovoltaic energy conversion will be economically competitive with alternative energy sources in the near term (1976-1985). These analyses were intended to support the implementation of the ERDA strategy to reduce photovoltaic array prices to \$500/kW_{pk} by 1986. The ERDA

strategy has two major elements: (a) a substantial technology development effort designed to produce significant near-term technological advances with cost-reduction potential; and (b) the development of interim markets that, taken together, will constitute a total market whose orderly growth will lead to further price reductions. The identification and evaluation of potentially significant near-term applications are therefore required in order that tactics to stimulate the growth of the necessary interim market may be formulated.

The rationale (and justification) for the ERDA strategy also includes the expectation that, when array prices reach (or closely approach) the 1986 goals, photovoltaic energy conversion will be able to compete economically in one or more of the larger markets for electric power (general residential power, central station power, etc.). The materialization of such major markets will require expanded array production capacity and will support the further technical improvements and cost reductions that are characteristic of the experience of similar industries. Therefore, another objective of the current study has been to identify the major photovoltaic missions that have the greatest market potential in the mid-term period (1985-2000) and determine under what conditions photovoltaic technology will be competitive in these missions. Work in pursuit of this objective represents a relatively direct extension of the analyses carried out in the preceding study, and the methodology developed in that project has been directly applicable.

The remaining two objectives, the preliminary analysis of critical external issues and the initial quantification of the societal costs of power production by conventional and photovoltaic methods, were chosen to support the continuing proper balance and effective strategic planning in the ERDA program.

Photovoltaic Mission Analysis: Objectives

Chart 1

OVERALL OBJECTIVE:

- TO SUPPORT THE FORMULATION, PLANNING, AND JUSTIFICATION OF THE ERDA NATIONAL PHOTOVOLTAIC PLAN
 - IDENTIFY PROMISING APPLICATIONS, ATTRACTIVE DEMONSTRATIONS, CRITICAL EXTERNAL ISSUES
 - PROVIDE PLANNING SUPPORT TO REFINE THE ERDA TECHNOLOGY IMPLEMENTATION PLAN (program strategy)

SPECIFIC OBJECTIVES:

- SURVEY AND EVALUATE NEAR-TERM (1976-1985) APPLICATIONS; IDENTIFY MOST PROMISING POTENTIAL CONTRIBUTORS TO ORDERLY MARKET GROWTH
 - CIVILIAN
 - DOMESTIC U.S.
- EVALUATE MOST PROMISING MAJOR MISSIONS FOR MID-TERM (1985-2000) PERIOD; DETERMINE CONDITIONS UNDER WHICH PHOTOVOLTAIC TECHNOLOGY CAN COMPETE AT ARRAY PRICES CONSISTENT WITH ERDA GOALS
- ADDRESS CRITICAL EXTERNAL ISSUES AND IDENTIFY SENSITIVITY OF PHOTOVOLTAIC SYSTEM TECHNICAL REQUIREMENTS TO SUCH FACTORS
- QUANTIFY SOCIETAL COSTS OF ALTERNATIVE ENERGY SOURCES AND IDENTIFY EQUALIZING INCENTIVES

STUDY FLOW CHART

The general approach adopted in this project is illustrated schematically in the accompanying flow chart. As indicated, the study was divided into six separate but related tasks. The primary emphasis has been on two of these, Tasks 1 and 2, while the remaining four were intended to provide supporting information.

Under Task 1, Analysis of Near-Term Missions, a survey was made of current and potential applications in which the photovoltaic conversion of solar energy is (or will be) economically competitive in the 1976-1985 period, as array prices are reduced from the current \$15/W_{pk} to the ERDA 1986 goal of \$0.50/W_{pk}. Only non-military U. S. applications were considered. Accomplishing this task required the development and application of a systematic procedure for identifying and screening possible photovoltaic applications and then carrying out technical and economic analyses in order to determine when and in what applications the technology can be expected to be competitive. The results were then used in developing quantitative estimates of the cumulative size of the near-term market for photovoltaic arrays in these non-military U. S. applications. A summary of the work on this task is presented in Charts 3-12, while a much more complete account is given in Volume 2, Survey of Near-Term (1976-1985) Civilian Applications in the United States.

Under Task 2, Analysis of Major Mid-Term Missions, the analytical procedures developed in the previous NSF-sponsored study (Ref. 1) were used in an extension of the earlier work on major missions (i.e., missions in which photovoltaic technology could have a significant effect on the national energy supply) in the 1986-2000 period. The emphasis continued to be on central station power applications, but the geographical coverage was extended to include five separate regions chosen to represent the contiguous 48 states of the U. S.

The effect of using concentrating collectors (for both high and low concentration ratios) was also investigated. In addition, the effect of different ownership options (i.e., homeowner versus utility system ownership) on the economics of residential on-site photovoltaic applications was briefly investigated, and a start was made on an investigation of photovoltaic total energy systems. The work on this task is presented in Charts 13-39 and is discussed in much greater detail in Volume 3, Major Missions for the Mid-Term (1986-2000).

The remainder of the project consisted of four supporting tasks. Under Task 4, Critical External Issues, an investigation was made of the environmental and occupational hazards of photovoltaic array production and deployment. Under Task 5, The Impact of Incentives, a preliminary study was made of the effects of a variety of governmental incentive strategies on the economics of photovoltaic central station power plants. Under Task 6, Societal Costs of Conventional and Photovoltaic Power Production, a study was made of the non-internalized social costs (costs not reflected in the price of electricity) of coal-fired electric power generation. In this volume, Charts 40-47 summarize the results of the work on these three tasks, while more complete accounts are given in Volume 4, Supplementary Studies.

The effort under Task 3, Review and Updating of the ERDA Technology Development Plan, was devoted almost entirely to providing direct support to the special Photovoltaic Program Planning Group. Since the accomplishments of the Group represent the collective efforts of a number of individuals from different organizations, it is not appropriate to discuss them in this report.

Study Flow Chart

Chart 2

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II. TASK 1. ANALYSIS OF NEAR-TERM MISSIONS

The objective of the Task 1 effort was to carry out a quantitative survey of near-term (1976-1985) civilian (non-military) markets for photovoltaic arrays in the United States. This section contains a discussion of the approach used in carrying out the survey and of the results that were obtained. A much more detailed discussion of this work can be found in Volume II, Survey of Near-Term (1976-1985) Civilian Applications in the United States.

STUDY FLOW: POTENTIAL NEAR-TERM PHOTOVOLTAIC MARKETS

The general approach used in carrying out the survey of near-term markets is shown on this chart. This approach was predicated on the assumption that many individual applications would be identified from an extensive literature search, from interviews with manufacturers and potential purchasers, and from "brainstorming," and that a procedure would be required to screen these applications rapidly in order to identify those with potentially sizable potential markets in the time period of interest.

A tree structure was used to group generically related application classes and to suggest applications in other branches of the tree once a representative application had been identified for one of the branches. Once a group of applications had been identified as having similar electrical load requirements, including duty cycle and storage needs, a cost break-even analysis (based on life cycle costs) was performed on a typical application from that class or group of applications. In most instances, the cost comparison between photovoltaic systems and alternative power systems was performed on a present-value basis, with the effective discount rate set at 9% and the cost escalation rate at 5%. Equating the present values of the life-cycle costs of the two competing power generation systems permitted the (approximate) determination of an

economically competitive photovoltaic array price. This price, in conjunction with the ERDA near-term array price goals (as a function of time) allowed the determination of the date of initial market penetration. This was assumed to occur in the year when the computed competitive array price matched the price goal.

The sizes of the potential markets for those photovoltaic applications with initial penetration dates prior to 1986 were determined from trend projections, where possible, or on the basis of expert judgment obtained in interviews with current and prospective users, together with appropriate total market statistics obtained from a variety of sources.

In all, about 50 application classes were determined to have important market potential for the time period of interest. Twenty-one of these market segments could be quantified, while the data base for the remaining application classes was found to be insufficient to permit quantification at this time.

Study Flow

POTENTIAL NEAR-TERM PHOTOVOLTAIC MARKETS

OVERVIEW OF LAND DOMAIN OF PHOTOVOLTAIC APPLICATIONS TREE

Applications derived from the literature search, interviews, and "brainstorming" were separated into generic groupings in order to permit conceptual design and economic analyses to be performed on typically representative applications rather than on every potential application. A tree structure using a hierarchical order (i. e. , with applications on lower levels of the tree constituting subgroupings of the applications above them) was found suitable for this purpose. The morphological character of such a tree structure also served another purpose, that of assuring consideration of similar applications in all of the tree domains if they had been identified for at least one of the domains.

Of the three major domains of the applications tree, Land, Airborne, and Marine, only the Land domain was subdivided into Remote, Rural, and Urban sub-domains. It was found, however, that the four major applications groupings, Sensors, Communications, Signals, and General Power and Lighting, could be used for all of the domains, although they did not necessarily contain equal populations or subgroupings.

Chart 4 shows an overview of the Land Remote domain, with most of the applications groupings defined to the 4th level. Chart 5 takes the Sensors/Data Processing/Transmit grouping and develops it to the 5th level. Chart 6 further exemplifies segregation of applications to the 6th level. For some of the applications groupings, it was not worthwhile on the basis of available market data to carry the segregation to this level, although technical definition to even lower levels was possible.

Because of study resource limitations, not all application groupings received equal attention. In general, minimum study coverage was given those application groups which exhibited a minimum market potential. For example, applications requiring array sizes measured in microwatts were not emphasized in this study since even markets for millions of units would require array production in the order of only hundreds of watts.

Overview of Land Domain of Photovoltaic Applications Tree

WITH DETAIL TO 5th LEVEL UNDER "SIGNALS"

DETAIL OF 5TH LEVEL OF LAND DOMAIN OF PHOTOVOLTAIC APPLICATIONS TREE

This chart, showing the segregation into application subgroupings of one of the major groupings, also exemplifies how market segmentation can be derived from the tree structure. Included in this applications group are sensors which may or may not be associated with processing systems such as analog to digital converters. Such processors may or may not encompass means of transmission of the raw or processed data to a central station, which either merely collects the data or also responds to it in a control mode. Data transmission may be by manual pickup of hard copy such as paper recording disks or tapes, in which case photovoltaic power would be used only for sensor and recording instrument operation, or it may be by radio, in which case an additional power requirement exists. Telephone transmission usually does not require a power source at the remote site but may require it at the central data collection point.

Some of the applications subgroupings on this chart are duplicated in other chart sections and in other domains. For example, weather and pollution sensors are listed in the Rural and Urban branches of the Land domain, as well as in the Airborne and Marine domains. Similarly, locators are also shown under the Communications branch of the tree since some of these devices act merely as transponders to communicators in the vehicle, while other designs perform a true sensing function by either detecting or by both detecting and identifying a vehicle or animal.

The following chart, Chart 6, further assists in evaluating these market segments by providing a framework for technical judgments concerning power needs of the sensor systems to be used for these several application subgroupings.

Detail of 5th Level of Land Domain of Photovoltaic Applications Tree

"SENSORS/DATA PROCESSING/TRANSMIT"

Chart 5

DETAIL OF 6TH LEVEL OF PHOTOVOLTAIC APPLICATIONS TREE UNDER INTRUSION SENSORS

Where market segmentation statistics permitted, the subdivision of applications to a sixth level, as shown on this chart, was worthwhile because it is at this level of the applications tree that power requirements for individual systems can be determined. An approximate measure of the total potential market can then be obtained by multiplying the number of unit applications by the average watts of peak power per unit application.

Of the specific (6th level) applications shown on this chart, for example, the closed circuit television camera (CCTV) power level can be expressed on a per unit-camera basis or on the basis of unit length of perimeter to be observed. The other sensors listed on this chart generally have power requirements expressed only on the basis of unit length of perimeter to be guarded, i. e., watts per foot of fence or border. It should also be noted that these estimates

of power requirements must also include those of the data transmission systems and, for remote sites, the needs of the control stations. The power requirements of sensor systems are generally so low that independently powered radio data links are cost-effective even in urban areas, and even if the sensor is mounted on a powerline pole. Photovoltaic systems are therefore believed to have wide application in the intrusion sensor market if the arrays can be assured of protection from damage caused by vandals and by the environment. The break-even array costs for these types of applications are well above current array prices, suggesting the possibility of immediate market penetration.

Detail of 6th Level of Photovoltaic Applications Tree Under Intrusion Sensors

PROJECTED 1980 ENERGY COSTS: PHOTOVOLTAIC SYSTEMS VERSUS DIESEL GENERATORS

As indicated earlier, the date of initial photovoltaic penetration of a given market was estimated by calculating the array price at which a photovoltaic system would be cost competitive with conventional power sources and then determining when array prices are expected to reach this level (if ERDA goals are realized). In order to simplify many of these cost break-even calculations, generalized analyses were carried out to define the conditions in which photovoltaic systems are cost competitive with conventional sources such as utility distribution lines, primary batteries, or engine generators (gasoline/diesel). The results of the analysis for the diesel generator case are shown in Chart 7. The cost of energy from diesel generators in the year 1980 is plotted as a function of the power demand of the load (expressed in terms of the equivalent continuous load), for different values of the 1980 diesel fuel cost and post-1980 fuel cost escalation rate. In calculating these energy costs, the figures used for operating cost were in accord with experience in normal civilian service. It is understood that military operating costs are higher.

Also plotted on the graph in Chart 7 are curves representing photovoltaic energy cost for various values of array cost (price). The photovoltaic system is assumed to incorporate three days of battery storage (at \$50/kWh), an amount judged sufficient to ensure reasonable continuity of service in a southwestern U.S. location. The energy cost figures shown in the chart represent levelized costs computed by first determining

the total present-value cost of 20 years of service, annualizing by multiplying by the capital recovery factor (based on an assumed discount rate of 9%), and then dividing by the annual energy production (in kWh). The resultant levelized energy costs are significantly higher than the projected costs during the first year of service (1980) and significantly lower than the projected costs in the year 2000, at the end of the 20-year period.

This chart indicates that if photovoltaic systems are to compete with diesel generators over the 1-15 kW power range, array prices must be reduced to \$2/W_{pk} even if high fuel prices (\$1/gal) and fuel price escalation rates (10%) prevail. At an array price of \$1/W_{pk} photovoltaic power would be competitive for continuous loads between 3 and 5 kW if diesel fuel cost \$1/gal and escalated at the 5% rate. If the escalation rate were 10%, photovoltaic power would be competitive for continuous loads of up to 10 kW.

Similar generalized analyses were carried out for the cases where the alternative power source was assumed to be (a) a utility power line or (b) a primary battery pack. In the former case, the prime cost-determining variable is the length of the additional power line that must be installed to serve the load, while in the latter case, the equivalent continuous power demand (i. e., battery capacity) is the prime variable.

Projected 1980 Energy Costs: Photovoltaic Systems VS Diesel Generators

POTENTIALLY LARGE PHOTOVOLTAIC MARKETS: RAILROAD GRADE CROSSING SIGNALS

Chart 8 and the three succeeding charts (9-11) summarize the information that was gathered about four representative near-term applications and present the associated market estimates. Each of the four represents a potentially large photovoltaic market.

Developing a quantitative estimate of the market associated with the railroad grade crossing application illustrated in Chart 8 was considerably more straightforward than was the case with most of the applications considered. Primarily responsible for this was the action by Congress in financing the installation of in-grade crossing signals as part of the Federal Highway Act of 1976. In preparation for this legislative action, a survey of crossings had been taken by cognizant government agencies, and the number of currently unpowered (without utility power) public crossings in the U. S. was known, as was the number of unprotected crossings. What was not known at the time of the evaluation of this market was the number of such unpowered crossings which would be designated to receive protection. The criteria that would be used in selecting which crossings should be protected (numbers of trains passing per day, numbers of automobiles crossing per day, speed of trains while passing, etc.) had not as yet been determined. Estimates of the potential market were therefore based on expert judgment by railroad and government officials.

Institutional factors may assist in the realization of this market. Demonstration of photovoltaic power for crossing signals has already been undertaken by two railroads, and serious consideration of solar power has been given by others. Railroads prefer independent power sources over the somewhat unreliable (in rural areas) utility power. Many unprotected crossings are in remote areas where utility power is unlikely to be available nearby, and traffic, both rail and highway, in many such remote areas is expected to increase. Finally, a very important factor is the availability of federal funds for the financing of the protection of such crossings.

Constraints on the realization of this market include the need for protection against vandalism and theft, a problem with which railroads are particularly familiar on remote and difficult-to-police trackage.

The estimates of the size of the photovoltaic market in this application (as presented in the chart) are based on the assumptions that (a) 10% of the 4000 new crossing signals installed each year under the Federal Highway Act of 1976 will be at crossings remote from utility power and (b) 80% of these new remote crossing signals will be powered by photovoltaic arrays. (If utility power is one mile or more away, it is estimated that photovoltaic power would be competitive at array prices in excess of \$20/W_{pk}.)

Potentially Large Photovoltaic Markets

RAILROAD GRADE CROSSING SIGNALS

MARKET ENVIRONMENT

- FORCING FUNCTION
 - HIGHER PROPORTION OF UNPROTECTED CROSSINGS REMOTE FROM UTILITY POWER
 - RAILROADS PREFER INDEPENDENCE FROM COMMERCIAL POWER
 - FEDERAL HIGHWAY ACT OF 1976 PROVIDES 125 MILLION FOR ~ 4000- 5000 CROSSING SIGNALS/yr ON PUBLIC ROADS
- STATISTICS - 1976
 - ABOUT 220,000 PUBLIC RAILROAD CROSSINGS (about 10% unpowered)
 - ABOUT 170,000 CURRENTLY UNPROTECTED
- POTENTIAL U.S. MARKET (estimate) BY 1985:
 - 3200 CROSSINGS AT 420W_{pk} ~ 1400 kW_{pk} CUMULATIVE
400/yr AT 420W_{pk} → 170 kW_{pk}/yr AFTER 1985

POTENTIALLY LARGE PHOTOVOLTAIC MARKETS: ILLUMINATED HIGHWAY SIGNS

Chart 9 provides an example of a market which is difficult to quantify because of the absence of an adequate data base, the extensive effort required to derive such a data base, and the strong influence of institutional rather than economic factors on the size of the market.

Although there is general agreement in the literature that illuminated road signs more effectively promote highway safety, retroreflective signs are commonly used because of cost considerations, even when utility power is available at the installation site. Public agencies, including the federal government, appear to prefer to allocate the bulk of their limited road construction and maintenance budgets to road surfacing rather than to providing signs and traffic control.

Traffic engineers apparently prefer illuminated signs when feasible, as indicated by the Interstate Highway System, which is federally financed and which has lighted signs or signals every half mile, on the average. This is a much higher incidence of lighted signs than is generally found on the rural roads in the U.S. The size of the potential market for photovoltaic systems, of course, also depends on the percentage of road miles which are close to utility power. No statistics on the location coincidence between utility power lines and paved rural roads could be found,

although some estimates for a single highway district in California indicate that about 10% of the road mileage is more than 1 mile from a power line. A much higher percentage is probably so far from a power line that construction of an extension (at \$15,000 per mile) would be too expensive for powering a road sign. The upper and lower limits of the market estimates shown in this chart reflect two alternative limiting assumptions: (a) that one photovoltaically powered road sign would be required for each 10 miles of the 10% fraction of U.S. roads that is more than 1 mile from utility power (extrapolating from the California sample) and (b) that one photovoltaically powered illuminated road sign would be required for every 10 miles of the entire rural road system because utility power would be uneconomically distant from the road at those points. The power estimates per sign were based on strobe illumination and are therefore very conservative.

New developments in sign lighting are reducing power requirements, as are new concepts of activating signs only when required. These developments should aid acceptance of photovoltaic power. However, since decisions in this market are not based solely on economics, quantitative market evaluation is very difficult.

Potentially Large Photovoltaic Markets

ILLUMINATED HIGHWAY SIGNS

MARKET ENVIRONMENT

- FORCING FUNCTION
 - LIGHTED SIGNS PROMOTE SAFETY
 - LARGE SEGMENT OF RURAL ROADS DISTANT FROM UTILITY POWER
- STATISTICS - 1976

	MILES
TOTAL U. S. ROADS	3,180,000
TOTAL SURFACED RURAL ROADS	2,450,000
FEDERAL-AID RURAL ROADS	827,000
34,000 mi OF INTERSTATE HAVE 63,000 LIGHTED SIGNS

PRELIMINARY ESTIMATES

EQUIVALENT CONTINUOUS POWER*, W	10
ARRAY SIZE, PEAK WATTS	70
SIZE OF MARKET UNITS	24,000-240,000
kW _{pk}	1,680-16,800
BREAK-EVEN ARRAY PRICE: \$216/W _{pk}	
ALTERNATIVE IS POWERLINE AT \$15,000 per MILE	
CUSTOMER CLASSES (examples)	
a. FEDERAL	
b. STATE	
c. LOCAL GOVERNMENT	
DATE OF REALIZATION	?

SOLID DATA LACKING:

MILES OF ROADS LACKING POWER (sample district in California ~10%)

NEED FOR SIGNING i.e., SOCIAL COST OF LACK OF ILLUMINATED SIGNING

DATA ON NEW LIGHTED SIGN (low power; lighted on demand) CONCEPTS UNDER DEVELOPMENT

*Typical for strobe

POTENTIALLY LARGE PHOTOVOLTAIC MARKETS: PRIVATE SERVICES MICROWAVE REPEATERS

Prospects look bright for penetration of the communications market by photovoltaic power in a variety of remote applications where power line extensions would be expensive and where automated, unattended engine generator operation requires expensive maintenance under conditions of increasing fuel prices. The most promising applications in terms of market size are the communication repeaters or relays. Such systems are often located on mountaintops to increase the link distance, and are, therefore, remote from the utility grid.

The common carrier market is less promising for photovoltaic application than is the private system market because common carrier stations are already in place for the most part, have utility power already brought to the site, and may face limited growth because of competition from satellite systems and from private microwave systems. The latter represents a better growth market and must often utilize more remote sites for its repeaters, with consequently higher costs for utility power from specially constructed power line extensions. Railroads and pipelines are interesting examples of industries that utilize in-house communication systems with considerable

line lengths and use microwave links to connect their communication nodes. In addition to the microwave trunk and branch lines, VHF repeaters are often used to furnish the final links with fixed or mobile receivers. Because of relatively shorter line distances, such private systems may be less likely to benefit from satellite transmission and thus may be more likely to expand ground repeater stations with increases in either message load or network size, or both.

Photovoltaic systems have already been used to power VHF repeaters for public safety services, for some state and federal government services, and on Indian reservations. In addition, a photovoltaic powered microwave telephone relay system was installed on an Indian reservation in 1976.

Other communication markets already penetrated or likely to be penetrated by photovoltaic power include the remote instrument market in which radio telemetry links via repeaters or satellites provide data links with data processor stations. Both urban and highway call boxes have already been deployed with photovoltaic power and are believed to have a high market potential. The radio control market also looks promising for photovoltaic penetration both in the industrial process control field as well as in traffic control systems.

Potentially Large Photovoltaic Markets

PRIVATE SERVICES MICROWAVE REPEATERS

ESTIMATES

MARKET ENVIRONMENT

- FORCING FUNCTION
 - GROWTH OF PRIVATE COMMUNICATION SYSTEMS
 - NEW REPEATER SITES LESS ACCESSIBLE TO UTILITY POWER
- STATISTICS - 1976
 - ABOUT 9000 REPEATER STATIONS LICENSED
 - PAST GROWTH ABOUT 10% PER YEAR
 - FUTURE GROWTH TO ACCELERATE

EQUIVALENT CONTINUOUS POWER*, W		220	
ARRAY SIZE, PEAK W		1500	
SIZE OF MARKET**	UNITS	CUM-1985	ANNUAL
		180	500
	kW _{pk}	3500	800
BREAK-EVEN ARRAY PRICE vs DIESEL: \$1.0/W _{pk} vs UTILITY: \$5.6/W _{pk}			
CUSTOMER CLASSES (examples) <ul style="list-style-type: none"> a. PUBLIC SAFETY b. INDUSTRIAL c. LAND TRANSPORTATION 			
DATE OF MARKET INITIATION: 1976			

* Typical for Private Line Service

** Excludes Common Carrier and Government Service

POTENTIALLY LARGE PHOTOVOLTAIC MARKETS: IMPRESSED CURRENT CORROSION PROTECTION - GAS WELL CASINGS

Another very promising application for photovoltaic systems is in providing power for impressed current corrosion protection (ICP) of a variety of metal structures, such as well casings, pipelines, offshore platforms, reinforcing rods in concrete structures (e.g., bridge decking). Although for new installations it must face competition from a variety of other methods capable of reducing or eliminating corrosion, such as coatings, wrappings, moisture-proof membranes, and galvanic anodes, ICP has a great advantage over these approaches when corrosion has already progressed to some degree because it can be applied to the structure in situ, and because it permits voltage and current to be adjusted to a corrosion potential specific to a site. ICP offers other advantages over galvanic anodes in many situations, and photovoltaic power sources can economically compete when utility power is distant, and even in some selected instances when utility power is conveniently available.

Chart 11 summarizes the information that has been gathered about one of these potential applications of photovoltaic power for ICP. In fact, this market had already been penetrated in 1976; ICP systems powered by photovoltaic arrays were in use to protect casings in a number of shallow wells in a Kansas gas field. Application of photovoltaically powered ICP to natural gas wells is currently restricted to shallow wells because the higher power requirements for deeper wells make photovoltaic systems less competitive in comparison to utility power or engine generator power. As array prices decrease in the near term, it is anticipated that deep gas wells will become a potential market. It is also anticipated that photovoltaic ICP will find increased application to water piping and wells, bridge decking, bridge piers, oil and gas pipelines, and other metal structures exposed to corrosive hazards.

Potentially Large Photovoltaic Markets

IMPRESSED CURRENT CORROSION PROTECTION - GAS WELL CASINGS

MARKET ENVIRONMENT

- FORCING FUNCTION
 - EXPENSE OF REPLACING OLD AND DAMAGED WELL CASINGS IS HIGH AND INCREASING
 - PRESERVATION OF EXISTING CASINGS
 - INCREASES LIFE OF FIELD-WELLS
 - INCREASES UTILIZATION OF RESOURCE
- STATISTICS - 1974
 - No. OF PRODUCING GAS WELLS IN U. S. = 127,000
 - No. OF PRODUCING GAS WELLS DRILLED (in 1974) = 7,240
 - SHALLOW WELLS (up to ~3700 ft deep) ABOUT 40% OF TOTAL
 - No. OF ACTIVE GAS WELLS IN UNDERGROUND STORAGE FIELDS = 16,000
- POTENTIAL U. S. MARKET (estimate) BY 1985
 - SHALLOW WELLS: 10,000 AT 60W_{pk} EACH → 600 kW_{pk} CUMULATIVE
PLUS 100 kW_{pk}/yr
 - DEEP WELLS: 6000 AT 750W_{pk} EACH → 4500 kW_{pk} CUMULATIVE
PLUS 800 kW_{pk}/yr

TASK 1: ANALYSIS OF NEAR-TERM MISSION - FINAL RESULTS

As indicated in the preceding charts, a very large number of potential applications were identified in the course of the survey. When these had been subjected to the screening process (which weeded out both those applications in which the total market for arrays would not be significant in size and also those applications for which the break-even array price would be less than \$1.00/W_{pk}), some 50 applications groups showed considerable promise as near-term markets for photovoltaic arrays. For 21 of these 50, the data base was sufficiently complete to permit quantitative estimates of the associated near-term array markets. As indicated in Chart 12, the estimated cumulative market in these 21 applications groups through 1985 is ~62 MW_{pk}, while the projected annual sales rate in 1985 is ~13 MW_{pk}/year.

The markets associated with the remaining 29 groups could not be quantitatively evaluated because of lack of an adequate existing data base and because the primary research required in

order to provide a data base was not feasible within the resources available to the study. If the average size of the markets associated with the unquantified groups, however, is comparable to the average for the quantified cases, then the total non-military U.S. market for arrays may well exceed 25 MW_{pk}/year in 1985. Foreign and U.S. military markets should add significantly to this total. The consensus of the photovoltaic industry representatives who were contacted is that the total foreign market over the near term may be several times as large as the domestic one because (a) most developing countries do not have a fully developed utility power grid, (b) major new installations such as pipelines and communication systems have been made in remote areas, and (c) fuel and maintenance costs for engine generator power are considerably higher in foreign countries than in the U.S.

The cumulative sales, to 1985, of 62 MW_{pk} when compared to 1975 sales of about ~200 kW_{pk} represents a growth rate of about 70% per year, on the average, over a 10-year period.

Task 1: Analysis of Near-Term Missions

FINAL RESULTS

• OBJECTIVE

- IDENTIFY AND EVALUATE POTENTIAL U.S. CIVILIAN PHOTOVOLTAIC APPLICATIONS FOR THE NEAR TERM (up to 1985)

• RESULTS

- NEAR-TERM APPLICATIONS PRIMARILY REMOTE, POWER LEVELS TO ~2 kW
- QUANTIFIED MARKETS FOR APPLICATIONS GROUPINGS SUCH AS:

	CUM POWER TO 1985 IN MW _{pk}	ANNUAL SALES IN 1985 IN MW _{pk}
REMOTE INSTRUMENTATION	1.3	0.13
RADIO	12.0	2.1
SIGNALS	12.0	3.6
FARMING	22.0	5.0
CORROSION PROTECTION	12.3	2.2
OTHERS	2.4	0.27
TOTAL	62.0	13.3

- POTENTIAL MARKETS NOT QUANTITATIVELY EVALUATED, SUCH AS

INDIAN RESERVATIONS, TRAFFIC CONTROL, WATER PUMPING, etc.

JUDGED TO BRING 1985 SALES TO ~25 MW_{pk}

- FOREIGN AND U.S. MILITARY MARKETS NOT INCLUDED
 - FOREIGN MARKETS PROBABLY LARGER THAN U.S. MARKETS OVER NEAR TERM

• CONCLUSION

- SUBSTANTIAL PRODUCTION BASE WILL DEVELOP

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III. TASK 2. ANALYSIS OF MAJOR MID-TERM MISSIONS

This section contains a discussion of the investigations that were carried out under the second of two major tasks of the project: the identification and evaluation of applications in which photovoltaic solar energy conversion is most likely to make a major contribution to the U.S. energy supply in the mid-term period (1986-2000). Work on this task was a direct extension of that carried out in the previous NSF-sponsored photovoltaic mission analysis project (Ref. 1) and took advantage of the analytical procedures and computer programs that were developed in the earlier study.

A more detailed discussion of the Task 2 effort can be found in Volume III, Major Missions for the Mid-Term (1985-2000), the third of the four volumes that comprise this report.

TASK 2: ANALYSIS OF MAJOR MID-TERM MISSIONS

The specific objectives of Task 2 are shown in Chart 13, along with a listing of the topics that were investigated. Primary emphasis was on studies of central station power plant applications, largely because photovoltaic systems may need to achieve an appreciable penetration of that market if they are to make a significant (1-2%) contribution to the U.S. energy supply by the year 2000. As indicated in the chart, the earlier analyses of the central station application were extended in four main areas. In the first of these, a brief investigation was made of the quantitative impact on the competitive position of photovoltaic plants of variations in the projected price of fuel and in the projected escalation in that price. A nomograph was constructed that permits a quick determination of the fuel price and escalation rates at which a particular solar plant concept would be competitive with a conventional generation plant; this nomograph is presented as Chart 14. (It is assumed in this study that the principal conventional alternative to the deployment of a photovoltaic plant would be the construction of an intermediate load steam generating plant fired by coal. In that case, the most appropriate fuel to be considered in using the chart would be coal.)

The detailed analytical procedures developed in the earlier study (summarized in Chart 15) were also used in evaluations of the performance and economics of photovoltaic power plants in five locations that were selected as reasonable representations of the principal climate areas and population centers of the nation. (The results

are presented in Chart 17.) Furthermore, in each of these locations, comparative analyses were made of plants employing three types of collector/concentrator (Charts 18 and 19): flat plate, N-S parabolic trough, and central receiver. (The investment cost figures used in the economic analysis of these examples are listed in Chart 16.) The results of these evaluations were used in the development of a generalized analysis (Charts 20-25) in which the maximum allowable cost of the area-related elements of the system is related to array efficiency and to average collected insolation. These investigations suggest that it will be difficult for concentrating systems to produce photovoltaic power at a competitive price unless profitable use can be made of the thermal energy that is also collected. A preliminary study was made, therefore, of high-concentration systems in which the thermal energy is sold or used in the generation of additional electricity (Charts 26-30).

The work of the earlier study on residential on-site applications (Ref. 1) was also extended, in one area, by a brief investigation of the impact of alternative ownership options (homeowner vs. utility ownership, Chart 31).

Finally, a start was made on a study of applications for photovoltaic total energy systems, i.e., systems that provide both photovoltaic electricity and solar thermal energy to meet the combined demand for electric and thermal energy at a single load point or a group of related load points. This work is presented in Charts 32-39.

Task 2. Analysis of Major Mid-Term Missions

OBJECTIVES

- TO IDENTIFY AND EVALUATE APPLICATIONS IN WHICH PHOTOVOLTAIC SOLAR ENERGY CONVERSION IS MOST LIKELY TO MAKE A MAJOR CONTRIBUTION TO THE NATIONAL ENERGY SUPPLY IN THE MID-TERM (1985-2000) PERIOD
- TO DETERMINE THE CONDITIONS UNDER WHICH PHOTOVOLTAIC SYSTEMS CAN BE ECONOMICALLY COMPETITIVE IN THESE APPLICATIONS AT ARRAY PRICES CONSISTENT WITH ERDA GOALS

TOPICS INVESTIGATED:

- CENTRAL STATION POWER PLANTS
 - EFFECT OF FUEL PRICE/ ESCALATION ON PHOTOVOLTAIC COST EFFECTIVENESS
 - EFFECT OF GEOGRAPHIC LOCATION
 - EFFECT OF COLLECTOR/CONCENTRATOR TYPE
 - EFFECT OF PROFITABLE USE OF THERMAL ENERGY IN HIGH CONCENTRATION SYSTEMS
- RESIDENTIAL ON-SITE SYSTEMS
 - EFFECT OF OWNERSHIP OPTION ON PHOTOVOLTAIC COST EFFECTIVENESS
- PHOTOVOLTAIC TOTAL ENERGY SYSTEMS (PTES)
 - POTENTIAL PTES MARKETS IN INDUSTRIAL PROCESS HEAT APPLICATIONS: PRELIMINARY ASSESSMENT
 - RESIDENTIAL PTES: PRELIMINARY ANALYSIS

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COST EFFECTIVENESS OF SOLAR POWER PLANTS AS A FUNCTION OF FUEL PRICE, ESCALATION: LEVELIZED FIXED CHARGE APPROACH

The ability of any type of solar power plant to compete economically with conventional fossil-fuel-fired power generation depends strongly on the cost of the fossil fuels. The graphs in Chart 14 are intended to illustrate this dependence and to permit the rapid identification of the fuel price/escalation conditions under which a given solar plant concept might be economically competitive with conventional generation.

The upper two figures in Chart 14 constitute a graphical representation of the levelized fixed charge method (Ref. 2) of determining the "levelized" busbar cost of electric energy, exclusive of fuel. In this approach, the busbar energy cost is determined by the requirement that the annual income from the sale of energy be constant (levelized) and that this stream of constant annual receipts over the life of the plant be exactly enough to defray the total cost of constructing the plant, operating and maintaining it over its service life, and paying the expected return on the capital investment.

This relationship can be expressed in the simple form

$$\text{BBEC (mills/kWh)} = \frac{(C)(FCR)}{8.76 \text{ PCF}} + \overline{\text{O\&M}} + \overline{\text{FL}}$$

where C is the total capital cost of the plant as of the first year of commercial operation (including interest during construction) expressed in dollars per rated kW of plant capacity; FCR is the fixed charge rate, which depends on the internal cost of capital to the utility system (the after-tax discount rate); PCF is the plant capacity factor, the ratio of the total annual output of the plant (in kWh) to the output which would have been produced if the plant had operated at full rated capacity for all 8760 hours of the year; O&M is the levelized cost (exclusive of fuel) of operating and maintaining the plant, expressed in mills/kWh; and $\overline{\text{FL}}$ is the

levelized cost of fuel, also expressed in mills/kWh. In constructing the graphs in Chart 14, the simplifying assumption was made that the $\overline{\text{O\&M}}$ for any type of power plant is ~ 3 mills/kWh. Although the fixed charge rate, FCR, for a given utility depends on its individual financial structure, typical values are in the 0.15-0.18 range.

The lower two graphs in the chart permit quick determination of $\overline{\text{FL}}$ on the basis of assumed values for the base-year price of fuel, FL_0 (in dollars per 10^6 Btu), for the fuel-price escalation rate, g, and for the after-tax discount rate, k. The relationship is

$$\overline{\text{FL}} = \text{CRF}_{k,N} \cdot \text{FL}_0 \cdot \text{HR} \cdot \left(\frac{1+g}{k-g} \right) \left[1 - \left(\frac{1+g}{1+k} \right)^N \right] \cdot 10^{-3}$$

where $\text{CRF}_{k,N} = k(1 - (1+k)^{-N})^{-1}$ is the capital recovery factor, the uniform annual payment, as a fraction of the original principal, that will fully repay a loan, including all interest, in N years at an interest rate of k. The remainder of the expression represents the present value cost, as of the year of start-up, of all the fuel that is used over the N years of plant service; HR is the heat rate, the ratio of thermal energy consumption to electric energy output. The graphs in Chart 14 are based on the choices: N = 30 years and HR = 9200 Btu/kWh.

To use this chart, it is necessary first to determine the total capital cost figures for the solar and conventional plants that are to be compared, as of the beginning of commercial operation, including interest during construction and, in the case of the solar plant, the total capital cost of the required backup capacity. One then enters the chart at the appropriate points on the abscissa of

the upper right-hand graph and proceeds vertically to the line for the assumed fixed charge rate and then horizontally across into the upper left-hand chart. At the intersections with the line representing the plant capacity factor, he drops vertically to the abscissa to determine the corresponding values for the busbar cost of energy, exclusive of fuel. If the solar plant is to compete economically with the conventional plant, $\overline{FL}$ must be equal to or greater than the difference in the fuel-less busbar energy cost figures.

The lower two graphs then permit the identification of the various fuel price/escalation scenarios that will result in the required value of $\overline{FL}$. The lower left-hand chart is entered at the point on the horizontal axis corresponding to this required $\overline{FL}$. The intersections of the vertical line from this point with the various FL_0 lines identify the required values for the levelizing fuel-price multiplier that is required in each case. One then proceeds horizontally across into the lower right-hand graph to intersect with a vertical line drawn from the assumed value of the after-tax discount rate, k . Interpolation between the curves in this graph permits an estimate of the fuel escalation rate that, in conjunction with the corresponding FL_0

value, will yield the required $\overline{FL}$. For each value of k on the abscissa scale in the lower right-hand graph the corresponding values of $CRF_{k,N}$ (for $N=30$) and FCR are also shown. (The determination of FCR from the value of k requires that some assumptions be made about the effective income tax rate, τ , and about other tax and insurance costs; the assumptions made in constructing the chart were the same as those used in the nominal case discussed in Reference 2; τ was taken to be 0.4 and the other tax and insurance costs were assumed equal to 0.0225 times the capital cost.)

In using the chart, one should, of course, choose a value for k (in the lower right-hand graph) that corresponds to the same value of FCR that was chosen in using the upper right-hand graph. It may also be objected that k and g are not completely independent, that g is coupled to some extent to the general inflation rate and that this rate influences the prevailing value of k , the expected internal rate of return on capital in a utility system. It seems likely, however, that the fuel escalation rate will be somewhat greater than that of general inflation and that, for example, a value of $k=0.08$ (a rate of return that corresponds to relatively mild inflation, 3 or 4%) could conceivably coexist with fuel escalation rates of 8% or more.

Cost Effectiveness of Solar Power Plants as a Function of Fuel Price and Escalation

LEVELIZED FIXED CHARGE APPROACH

GENERAL ANALYTICAL APPROACH

The procedures developed for evaluating photovoltaic applications in the earlier study (Ref. 1) continued to be used in the current project. They are based on the general approach illustrated in Chart 15. It contains three basic elements: (a) computer simulation of the performance of the photovoltaic system within mission constraints, (b) reliability analysis to determine how much conventional generation capacity must be provided as backup, and (c) economic analysis to determine the cost of providing mission power by photovoltaic means. This cost must then be compared with the cost of generating the required power by conventional methods.

The system simulation computations utilize a suitable model for the photovoltaic system, along with representations for the insolation input (characteristic of the geographical location) and for the electric power demand that characterizes the specific mission under study. These performance computations are carried out for a full year of simulated operation, and the results serve as inputs to both the reliability analysis and the economic analysis.

The reliability analysis methodology reflects the assumption that a photovoltaic system will be required to meet the same reliability standards as would be imposed on an alternative energy source. Because of the variability of solar energy

(and the high cost of energy storage), this requirement implies the necessity for a backup source of power. In this study, it has been assumed that the required backup power will be provided by conventional generating plants via the transmission/distribution grid of a utility system. The reliability analysis determines the amount of additional conventional capacity that must be provided in order to ensure that the utility system can provide the needed backup without reducing the overall reliability of service. The capital cost of this additional backup capacity is part of the cost of providing photovoltaic power and is therefore one of the inputs to the economic analysis. In the current study, the economic evaluations have been based on the levelized fixed charge approach that is discussed in the preceding chart. The economic analysis, in addition to providing photovoltaic power costs for comparison with the cost of conventional power, also provides estimates of the economic requirements (e.g., array cost goals) that must be satisfied if photovoltaic power production is to be economically competitive.

General Analytical Approach

INVESTMENT COST BREAKDOWN FOR PHOTOVOLTAIC CENTRAL STATION POWER PLANTS

The procedure outlined in the previous chart was used to investigate the effect of geographic location and collector/concentrator type on the performance and economics of photovoltaic central station power plants. Simulation computations were made of the performance of 100 MW (rated) plants at five locations: Inyokern, Calif.; Miami, Fla.; Sterling, Va.; Cleveland, Ohio; and Seattle, Wash. (The rated capacity of a photovoltaic power plant, in this study, is determined by the power-handling capability of the power conditioning system. In the analysis the rated plant capacity is typically kept fixed, while array area is varied parametrically.) Three different collector/array concepts were simulated: (a) air-cooled flat-plate silicon array, tilted about an east-west axis to an angle (relative to the horizontal) equal to the local latitude, (b) parabolic trough (concentration ratio = 20), with longitudinal axis horizontal and oriented north-south, east-west tracking, and air-cooled silicon cells (with cooling fins), and (c) central receiver concentration system (concentration ratio = 600) with water-cooled AlGaAs/GaAs arrays. (In the central receiver configuration, large numbers of steerable mirrors, or heliostats, are used to reflect sunlight onto photovoltaic arrays attached to the exterior surface of a tower-mounted receiver.)

The results of the simulation computations and associated reliability analyses provided two of the three main inputs to the economic analysis, the third being the total investment cost of the photovoltaic power plant. The cost assumptions that were used are tabulated in Chart 16, which contains breakdowns of the investment costs for three different power plant configurations. These breakdowns show that the capital cost of a photovoltaic plant is dominated by the cost of the collector/concentrator structure and (in the flat-plate case) the cost of the arrays. The only other significant

elements are the cost of the power conditioning system and the cost of storage, if any.

The capital cost figures used for the collector/concentrator structure in the parabolic trough and central receiver cases were based on a re-examination of engineering designs and cost estimates carried out by Honeywell, Inc., in collaboration with Black and Veatch (Refs. 3 and 4), for similar structures to be used in solar thermal power plants. The resulting unit costs, in 1975 dollars, are \$63.90/m² and \$59.80/m² for trough and heliostat, respectively. Also, an independent design was prepared, based on the same engineering standards and assumptions, for a fixed-tilt non-concentrating support structure for use with flat-plate arrays. When costs were estimated on the same basis as for the more complicated structures, a unit cost of \$15.20/m² was obtained.

The unit cost of the silicon arrays used in the flat-plate and parabolic trough systems was assumed to be \$100/kW_{pk}, or \$13.50/m² if the nominal array efficiency is 13.5% (15% cell efficiency, 90% packing factor). In the central receiver case, the unit capital cost of the AlGaAs/GaAs arrays (including the receiver structure to which the cells are attached) was assumed to be \$10,000/m².

The total cost of the power conditioning subsystem was assumed to be \$70/kW for the large-scale equipment that would be used in central station power plants. The total cost of battery storage was taken to be \$40/kWh, which represents the total present value cost of this subsystem, including any needed replacements, over the assumed 30-year life of the plant. The figure shown in the chart therefore represents the cost of a storage capacity of 5 kWh for every kW of rated plant output.

Investment Cost Breakdown for Photovoltaic Central Station Power Plants

1975 DOLLARS PER RATED KILOWATT

COLLECTOR TYPE	FLAT PLATE	NS PARABOLIC TROUGH	CENTRAL RECEIVER
COLLECTOR APERTURE (10^6 m^2)	2.24	2.16	2.14
CELL TYPE	Si	Si	AlGaAs/GaAs
CAPITAL COSTS			
COLLECTOR STRUCTURE	341	1382	1284
ARRAYS	302	15	357
DC WIRING	27	35	53
TOWER	-	-	59
LAND	12	12	9
STRUCTURES/FACILITIES	11	11	11
POWER CONDITIONING	70	70	70
ELECTRIC STORAGE	200	200	200
ELECTRIC PLANT EQUIP	16	16	16
MISC PLANT EQUIP	6	6	6
ALLOWANCE FOR COOLING	-	-	10
TOTAL BASIC PLANT	985	1747	2075
SPARES/CONTINGENCIES	79	140	166
INDIRECT COSTS	231	307	343
INTEREST DURING CONSTR	165	281	331
PLANT INVESTMENT COST	1460	2475	2915

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LEVELIZED BUSBAR ENERGY COST: PHOTOVOLTAIC CENTRAL STATION POWER PLANTS WITH FLAT-PLATE COLLECTORS

As mentioned in the text accompanying the preceding chart, simulation computations were made of the performance of photovoltaic power plants incorporating three different types of collector/concentrator and operating at five different sites. For each location and collector/concentrator type, simulation runs were made for a range of values of the total collector area (keeping the rated plant capacity fixed at 100 MW). In order to keep the total amount of computation within reasonable limits, the assumed amount of electric storage capacity was not, in general, varied but was kept fixed at $5(10^5)$ kWh. This value was selected because the earlier study (Ref. 1) had shown that 5 hours of storage was sufficient to permit a photovoltaic plant to serve intermediate loads (plant capacity factor PCF ~ 0.4). For one of the locations (Sterling), however, an additional set of runs was made, for each collector/concentrator configuration, with the storage capacity set at 0.

For each of these simulation runs, reliability analyses were also carried out and determinations were made of the amount of conventional backup capacity that would be required in order to maintain overall utility system reliability. The utility system model used in each case was one that was designed to be representative of the region in which the photovoltaic plant was presumed to be located. All of these reliability analyses were carried out for approximately the same degree of solar penetration, 5% (i. e., solar capacity equal to $\sim 5\%$ of maximum utility system demand).

The results of the simulation computations and reliability analyses were then used as inputs to the levelized fixed charge economic analysis, along with figures for the investment cost of the plant. The resulting figures for levelized busbar energy cost (in terms of 1975 dollars) for the flat-plate systems having 5 kWh/kW of storage capacity are displayed graphically in Chart 17. As indicated

there, the fixed charge rate was assumed to be 15% and the levelized operating and maintenance cost to be 3 mills/kWh. Also shown in the graph are horizontal lines representing the levelized busbar energy cost for electricity from a conventional intermediate load coal-fired plant (costing \$550/kW rated) for the three different coal price/escalation scenarios summarized in the lower left corner of the chart. There FL_0 represents the price of coal (expressed in 1975 dollars per million Btu) in the first year of commercial operation (1990, in this study) and g is the post-1990 coal price escalation rate. These three price/escalation scenarios (low, medium, high) are believed to fairly well cover the range of possibilities that could be experienced.

The results of the simulation computations do not actually depend separately on the baseline ($T = 70^\circ\text{C}$) array efficiency or the total collector area but rather on their product. One can therefore interpret the results of any given computational run as representing any of a wide range of different combinations of values for efficiency and collector area that have the same product. The collector-area values shown in these graphs are those that result when the assumption is made that at 70°C the silicon cell efficiency is 12% and that of AlGaAs/GaAs cells (under high-concentration illumination) is 22%; the corresponding figures at room temperature (20°C) are 15% and 24.5%, respectively. The array packing factor was assumed to be 0.9.

The minima in the curves representing the dependence of $\overline{BBEC}$ on collector/concentrator aperture area are a result of the fact that all points on each curve represent plants with the same "name-plate" rating, i. e., the capacity of the power conditioning system is the same (100 MW output) for each plant. When the collector area is small, the power conditioning system is seldom driven to its limiting capacity and the overall plant capacity

factor is small and the busbar energy cost is correspondingly high. As the collector aperture is increased, the limiting power conditioning capacity is reached more frequently. The excess array output energy in these instances is dispatched to storage for use when array output falls. The effect is to extend the period of the plant operation at high output levels and thus to increase

the plant capacity factor and decrease the busbar energy cost. If the storage system is fully charged, however, any excess energy (above the power conditioning handling capability) must be wasted. As collector aperture becomes large, the amount of wasted energy increases rapidly and the overall busbar cost of energy also rises.

Levelized Busbar Energy Cost

PHOTOVOLTAIC CENTRAL STATION POWER PLANTS WITH FLAT PLATE COLLECTORS

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}

FIXED CHARGE RATE = 0.15

LEVELIZED O&M COST = 3 mills/kWh

ARRAY PRICE = \$100/kW_{pk}

ARRAY EFFICIENCY (20°C) = 0.135

FUEL PRICE CASES

	FL_0 (\$/10 ⁶ Btu)	g
A	0.75	0.05
B	1.25	0.06
C	1.75	0.07

LEVELIZED BUSBAR ENERGY COST: PHOTOVOLTAIC CENTRAL STATION POWER PLANTS AT INYOKERN

The dependence of photovoltaic power plant economics on collector/concentrator type is illustrated in Chart 18. The curves in this chart represent further results of the detailed mission evaluation calculations that were discussed in connection with the preceding chart. Shown are levelized busbar energy cost figures, as a function of collector area, for three different plant configurations at Inyokern, in the Mojave Desert region of California. Each of the plants represented in the chart incorporated 5 kWh/kW of electric storage capacity. As in the preceding chart, horizontal lines have been drawn on the graphs to indicate the busbar cost of energy from a coal-fired power plant for the three fuel price/escalation scenarios.

These results suggest strongly that photovoltaic power plants using concentrators are unlikely to be competitive economically with the coal-fired alternative

source under the operating conditions represented in the analysis. (The high capital cost of concentrator systems and the reduced collection efficiency resulting from various optical loss mechanisms are the main reasons for the relatively high busbar energy cost in these cases.) In such systems, however, a large amount of heat energy is also collected and must be disposed of (via convection from the cooling fins in the parabolic trough case, via the cooling water in the central receiver case). If this thermal energy could be put to some economically advantageous use, the competitive position of concentrating systems might change dramatically. As was indicated earlier, a preliminary investigation of this possibility, in the central receiver case, was carried out. The results are discussed later in this report (Charts 26-30).

Levelized Busbar Energy Cost

PHOTOVOLTAIC CENTRAL STATION POWER PLANTS AT INYOKERN

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}

FIXED CHARGE RATE = 0.15

LEVELIZED O&M COST = 3 mills/kWh

FLAT PLATE ARRAY PRICE = \$100/kW_{pk}

FUEL PRICE CASES

	FL ₀	(\$/10 ⁶ Btu) g
A	0.75	0.05
B	1.25	0.06
C	1.75	0.07

LEVELIZED BUSBAR ENERGY COST: PHOTOVOLTAIC CENTRAL SYSTEM POWER PLANTS AT STERLING, VIRGINIA

The curves in Chart 19 represent the levelized busbar energy costs for the same three photovoltaic plant configurations as were represented in the previous chart, but operating at Sterling, Va., (near Washington, D.C.) rather than at Inyokern. A comparison of the solid curves in Chart 19 (corresponding to energy costs for plants with 5 hours of storage) with those in Chart 18 indicates the relative penalty paid when a solar plant is operated on the northern fringe of the U.S. sunbelt rather than in the southwestern desert.

The principal reason for presenting this chart, however, is to illustrate the differences in the cost of energy from photovoltaic systems with and without storage. The dashed curves in the chart correspond to systems with zero storage capacity (except, perhaps, for the minimal amount which may be needed to smooth out transients in output that would be produced by the motion of broken cloud cover). It is

evident from the curves that the energy cost is lower when no storage is provided. Although the plants with storage have considerably greater plant capacity factors and require less conventional backup (or, in other words, provide greater capacity displacement), these advantages are outweighed by the effect of the capital cost of the storage system. This result is in disagreement with one of the general conclusions reached in the earlier Photovoltaic Mission Analysis study (Ref. 1). The difference is a direct result of differences in the assumed cost of battery storage in the post-1985 period. The number used in the earlier study was \$20/kWh (present value of the cost of storage, including battery replacements if needed, for the 30-year life of the photovoltaic plant), while that used in the present study is \$40/kWh. The higher figure is based on more recent information and projections and is believed to be more consistent with extensions of present battery technology.

Chart 19

Levelized Busbar Energy Cost

PHOTOVOLTAIC CENTRAL STATION POWER PLANTS AT STERLING, VIRGINIA

ELECTRIC STORAGE
 — 5 kWh/kW
 - - - 0

FIXED CHARGE RATE = 0.15

LEVELIZED O&M COST = 3 mills/kWh

FLAT PLATE ARRAY PRICE = \$100/kW_{pk}

FUEL PRICE CASES

	FL_0 (\$/10 ⁶ Btu)	g
A	0.75	0.05
B	1.25	0.06
C	1.75	0.07

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ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC CENTRAL STATION PLANT

The preceding four charts displayed representative examples of the results of detailed technical and economic analyses of three specific types of photovoltaic power plants in five specific locations. These results have been used as starting points in the formulation of a much more generalized and readily applicable procedure for the approximate economic evaluation of photovoltaic central station power plants. This procedure leads to a set of graphs, in which the maximum allowable area-related cost of a photovoltaic plant (in $\$/m^2$) is plotted against average collected insolation (which depends on plant location and overall collector efficiency), with array efficiency as a parameter. Such costs are considered to be "allowable" if they are low enough to permit the photovoltaic plant to compete economically with a conventional coal-fired intermediate load plant.

Graphs of this type have been prepared both for photovoltaic power plants incorporating 5 hours of storage capacity and for plants with no storage. Chart 20 contains one such graph for the 5-hour storage case; related generalized representations of the same case are presented in Charts 21 and 22. Corresponding curves for the no-storage case are shown in Charts 23-25.

The generalized analysis of plants with storage was designed to fit plants whose array area is adjusted to provide a plant capacity factor of 0.4, corresponding to intermediate load operation. The first step in the creation of the summary graphs in this case was to determine the total investment cost (expressed in 1975 dollars per rated kW of output) at which the photovoltaic plant could compete economically with an intermediate load (PCF = 0.4) coal plant costing \$550/kW, when fuel prices and price escalation rates followed one of the three standard scenarios considered in Charts 17-19. Appropriate allowances for spares, contingencies, interest during construction, and indirect costs were subtracted from the total investment cost, leaving a figure that represented the total allowable capital cost of all of the plant subsystems. This allowable capital cost total was then

separated into area-related (collector, array, DC wiring, land, and land preparation) costs and costs that are independent of array area and determined only by the rated plant capacity (100 MW) and the plant capacity factor (0.4). The latter category includes structures (other than collector structures), facilities, power conditioning equipment, the storage subsystem, the remaining electric and miscellaneous plant equipment, and any required conventional backup capacity.

The next step was to develop a generalized relationship defining the required amount of collector area (in order to make PCF = 0.4) as a function of array efficiency and of the average amount of insolation collected per unit collector area. The construction of the generalized expression for the array area (in m^2 per rated kW of plant output) required the use of an approximate value for the efficiency of the remainder of the plant (including the effect of losses incurred in cycling some of the array output into and out of storage) that was derived from the detailed evaluations discussed in Charts 16-19. The expression for the total allowable area-related cost of the plant (in $\$/kW_{rated}$) was then combined with that for the collector area in (m^2/kW_{rated}) to yield the desired summary equation, an expression for the allowable area-related cost (now in terms of $\$/m^2$) as a function of array efficiency and of average collected insolation.

Chart 20 presents, in graphical form, one example of such a generalized summary relationship, for the case where fuel prices and escalation rates correspond to Case B (moderate). The four vertical lines superimposed on the graph correspond to values for average collected insolation, derived from the detailed system simulations, for flat plate collectors and for either N-S parabolic trough or central receiver concentrators (the values for these two cases were virtually identical) at Inyokern, California, and Sterling, Virginia.

As an example of the utility of this chart, consider the case of a plant with flat-plate collectors located

at Inyokern. The average collected isolation in this case is indicated by the heavy unbroken vertical line on the graph. When land, wiring, and structure costs (from Chart 16) are subtracted from total area-related costs obtained from Chart 20, values for allowable array cost are obtained. For example:

Nominal array efficiency	0.14	0.18	0.22
Allowable area-related cost (\$/m ²)	28.70	36.80	45.10
Less support structure (\$/m ²)	15.20	15.20	15.20
Less land, wiring (\$/m ²)	<u>1.70</u>	<u>1.70</u>	<u>1.70</u>
Allowable array cost (\$/m ²)	11.80	19.90	28.20
(\$/kW _{pk})	84.	111.	128.

Allowable Area-Related Cost for Photovoltaic Central Station Plant

ELECTRIC STORAGE CAPACITY: 5 kWh/kW_{rated}

ALTERNATIVE: COAL-FIRED INTERMEDIATE
LOAD PLANT

FIXED CHARGE RATE: 0.15

AFTER-TAX DISCOUNT RATE: 0.08

FUEL PRICE CASE B

$FL_0 = \$1.25/10^6 \text{ Btu}$

POST-1990 FUEL ESCALATION
RATE = 0.06

INYOKERN

— FLAT PLATE

— TROUGH, CENTRAL
RECEIVER

STERLING

- - - FLAT PLATE

- - - TROUGH, CENTRAL RECEIVER

MINIMUM ALLOWABLE ARRAY EFFICIENCY: PHOTOVOLTAIC CENTRAL STATION
POWER PLANT WITH FLAT PLATE SOLAR ARRAYS
(5 HOURS STORAGE)

The generalized analysis used in the construction of the graph in Chart 20 can also be used to develop graphs that more directly illustrate the relationship between array efficiency and allowable array price for a given type of collector/concentrator at any desired location. In the flat plate case, for example, if the costs of support structure ($15.20/\text{m}^2$) and of DC wiring, land, and land preparation ($\sim \$1.70/\text{m}^2$) are subtracted from the allowable area-related cost, the remainder represents the allowable array cost (price). Then, if appropriate values for the average collected insolation are substituted into the equation, the result is an equation relating allowable array price (in $\$/\text{m}^2$) directly to array efficiency. In order to express these allowable array prices in the customary units of $\$/\text{kW}_{\text{pk}}$, it is only necessary to divide by the array efficiency.

Presented in Chart 21 are curves representing this relationship between allowable array price ($\$/\text{kW}_{\text{pk}}$) and array efficiency for flat plate systems at two locations and for all three of the standard fuel price/escalation scenarios. This method of graphical

display was suggested in part by somewhat similar displays in a report on a study by E. A. DeMeo (Ref. 5) of the use of CdS arrays in photovoltaic power plants. The principal messages of this chart are (a) that there is a minimum allowable array efficiency associated with each location and fuel-price scenario and (b) that increasing the efficiency yields a major benefit in the form of increases in the allowable array price. The chart indicates, for example, that if fuel prices and escalation rates follow the Case B scenario, the arrays for a flat-plate photovoltaic power plant at Inyokern would have to have an efficiency of greater than 8% in order for the plant to be economically competitive, even if the array price were zero. However, if an array efficiency of 16% were achieved, then an array price of about $\$100/\text{kW}_{\text{pk}}$ would be competitive. If fuel prices follow the Case C scenario, the minimum efficiency is relaxed appreciably, to about 6%, and an efficiency of only 7.5% is required when the array price is $\$100/\text{kW}_{\text{pk}}$. Furthermore, increasing the efficiency to 14% leads to a doubling of the allowable array price to $\$200/\text{kW}_{\text{pk}}$. (It should be noted that these numerical results are, of course, sensitive to changes in the assumed values for the costs of support structure and of land.)

Minimum Allowable Array Efficiency

PHOTOVOLTAIC CENTRAL STATION POWER PLANT WITH FLAT-PLATE SOLAR ARRAYS

MAXIMUM ALLOWABLE ARRAY PRICE FOR PHOTOVOLTAIC CENTRAL STATION POWER PLANT IN CENTRAL RECEIVER CONFIGURATION

One theme that pervades all of these analyses is the strong sensitivity of photovoltaic plant economics to array efficiency. Although the ultimate efficiency of single structure photovoltaic cells appears to be limited to no more than about 25%, a number of multiple-structure concepts have been suggested that might have appreciably higher overall efficiencies. One suggestion is the use of spectrally selective optics to direct different portions of the solar spectrum to separate photovoltaic devices with high response in the selected wavelength regions. Such complicated structures would clearly be more expensive to produce than the more conventional cells, and it is of interest to ask how much of an increase in array price can be tolerated (particularly in high-concentration systems) in return for very high array efficiency.

The generalized analytical approach discussed earlier has been used to provide some insight into this question, in the special case of concentrators in the central receiver configuration. For this purpose, the previously obtained equations for allowable area-related cost were corrected slightly to take into account the small differences in balance-of-plant cost (mainly the cost of water cooling) and in backup capacity requirements, which were neglected in the earlier analysis in the interest of generality.

To obtain the corresponding equation for array cost alone, it was only necessary to deduct the costs associated with the other area-related elements: collectors (heliostats), land, DC wiring, and, in this case, the central tower. The total of these costs is, for a plant with PCF = 0.4, approximately \$66/m², on the basis of the assumptions used in the more detailed analysis. If this figure is subtracted from the allowable area-related cost, the remainder represents the array cost in dollars per m² of collector area and can be expressed as C_{ar}/X , where C_{ar} is the array cost in dollars per m² of array and X is the geometric concentration ratio.

The relationship between C_{ar}/X and average collected insolation, for various values of the array efficiency, is shown in Chart 22, for the Case C fuel price scenario. The vertical dashed lines represent the average collected insolation for central receiver collectors at Inyokern and Sterling. This figure indicates, for example, that if array efficiencies as high as 36% could be reached, the allowable value for C_{ar}/X for a plant at Inyokern would be \$25/m². If the geometric concentration ratio were 600, then one could afford to pay \$15,000/m² for the arrays themselves.

Maximum Allowable Array Price for Photovoltaic Central Station Power Plant in Central Receiver Configuration

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW

FUEL PRICE CASE C

$FL_0 = \$1.75/10^6 \text{ Btu}$

POST-1990 FUEL ESCALATION
RATE = 0.07

ALLOWABLE AREA-RELATED COST OF PHOTOVOLTAIC CENTRAL STATION PLANT (NO STORAGE)

A generalized analytical procedure similar to that used for plants with storage has been formulated for evaluating photovoltaic power plants without storage. In the absence of the smoothing effect of storage on plant output, it is relatively meaningless to assign such plants a "rated" output or to express plant performance in terms of a plant capacity factor. In these cases, therefore, the annual average plant output (total annual production, in kWh, divided by 8760) was used as the measure of plant performance. Elements of the capital cost of the plant were expressed in terms of dollars per average kW rather than dollars per rated kW.

As in the case of plants with storage, the first step in the analysis procedure was to determine the maximum total investment cost (including the capital cost of conventional backup) that would permit a photovoltaic plant without storage to compete economically with an alternative conventional plant with equivalent performance (i. e., with the same average power output). It was assumed that the photovoltaic plants under consideration were essentially the same in design as plants with storage except for (a) the absence of the storage system and (b) the incorporation of a power conditioning system with significantly higher rated capacity (to handle the peak midday output of the array). The conventional alternative was assumed to be the same as before, namely, a coal-fired intermediate load (PCF ≈ 0.4) plant costing about \$550/kW rated. In terms of average power output, this cost would then be $\sim \$1375/\text{kW}_{\text{av}}$.

The remainder of the generalized analysis was carried out in the same manner as that used for plants with storage, except that the required array area, adjusted to provide the same average output as the designated conventional alternative, was initially expressed in terms of m^2 per average kW. An equation relating array area (in $\text{m}^2/\text{kW}_{\text{av}}$), array efficiency, and average collected insolation was used along with the expression for allowable area-related cost (in $\$/\text{kW}_{\text{av}}$) to develop expressions relating the allowable area-related cost (now in $\$/\text{m}^2$) to array efficiency and average collected insolation.

Chart 23 displays the result for fuel price Case B. The chart conveys the same general message as Chart 19, namely, that no-storage systems have an economic advantage where storage costs are no smaller than the \$40/kWh figure that was used in this study. For example, Chart 23 shows that the allowable area-related cost for a flat-plate plant at Inyokern, for an array efficiency of 0.14, is $\sim \$42/\text{m}^2$ (as compared to $\$28/\text{m}^2$ in Chart 20 for the corresponding system with storage). If the total cost of support structure, DC wiring, and land is taken to be $\sim \$17/\text{m}^2$ (as before), the array price can be $\sim \$25/\text{m}^2$ or $\sim \$180/\text{kW}_{\text{pk}}$. For a no-storage central receiver plant at Inyokern, however, even for an array efficiency of 0.22, the allowable area-related cost is still only about $\$53/\text{m}^2$, less than the projected cost of the heliostats alone.

Allowable Area-Related Cost for Photovoltaic Central Station Plant - No Electric Storage

Chart 23

ALTERNATIVE: COAL-FIRED INTERMEDIATE
LOAD PLANT

FIXED CHARGE RATE: 0.15

AFTER-TAX DISCOUNT RATE: 0.08

FUEL PRICE CASE B

$FL_0 = \$1.25/10^6 \text{ Btu}$

POST-1990 FUEL ESCALATION
RATE = 0.06

IN YOKERN

—— FLAT PLATE
—— TROUGH, CENTRAL RECEIVER
STERLING
—— FLAT PLATE
—— TROUGH, CENTRAL RECEIVER

MINIMUM ALLOWABLE ARRAY EFFICIENCY: PHOTOVOLTAIC POWER PLANT
WITH FLAT PLATE ARRAYS (NO STORAGE)

The relationship between allowable array price and nominal array efficiency for a flat plate photovoltaic power plant without storage is illustrated in Chart 24. These curves are analogous to those for the 5-hour storage case that were presented in Chart 21 and were constructed in the same way. The estimated values of all area-related costs other than that for the array itself were subtracted from the total allowable area-related cost (as illustrated in Chart 23). As in the previous calculation, these other costs amounted, in the flat plate case, to $\$16.90/\text{m}^2$ ($\$15.20/\text{m}^2$ for support structure, and $\$1.70/\text{m}^2$ for DC wiring, land, and land preparation). The remaining expression then represents the dependence of the cost of the array, in $\$/\text{m}^2$, on array efficiency and on average collected insolation. As before, the expression was then divided by array efficiency in

order to provide an equation for array cost in $\$/\text{kW}_{\text{pk}}$ rather than $\$/\text{m}^2$.

The results for plants at Inyokern and Sterling and for fuel price Cases A, B, and C are shown in Chart 24. These curves show, for example, that if fuel prices follow the Case B (moderate) scenario, the minimum array efficiency for an economically competitive flat plate photovoltaic power plant at Inyokern is $\sim 5.6\%$, even if the array price is zero. However, if the array efficiency increases to only 8% , then an array price of $\$100/\text{kW}_{\text{pk}}$ is competitive, and a 14% efficiency implies economic viability at $\$300/\text{kW}_{\text{pk}}$. These minimum efficiency values are somewhat lower than those obtained in the case of plants with storage (Chart 21), again reflecting the unfavorable economic effect of storage when the storage cost is $\$40/\text{kWh}$ or more. (As was noted in connection with Chart 21, the numerical results in this case also are sensitive to changes in the assumed support structure and land costs.)

Minimum Allowable Array Efficiency

PHOTOVOLTAIC POWER PLANT WITH FLAT PLATE ARRAYS

ALLOWABLE ARRAY PRICE: PHOTOVOLTAIC POWER PLANT IN
CENTRAL RECEIVER CONFIGURATION (NO STORAGE)

As was true for plants with storage, it is instructive in the no-storage case to determine how large an array price can be tolerated in return for very high array efficiency. The approach used was essentially identical to that taken earlier except that total system costs were expressed in dollars per average kW rather than in dollars per rated kW. As in the earlier calculation, the generalized expressions for allowable area-related costs were adjusted slightly to take into account the small difference in balance-of-plant costs between the generalized figure used earlier and the value that is specific to central receiver systems. The costs of the other area-related elements (land, heliostats, DC wiring, towers) - a total of \$66/m², as in Chart 22 - were then subtracted. The result was a set of equations (one for each of the three standard fuel price scenarios) representing the dependence on array efficiency and average collected

insolation of the ratio C_{ar}/X , where C_{ar} is, as before, the allowable array price (in dollars per m² of array) and X is the geometric concentration ratio.

The relationship for the Case C fuel price scenario is displayed graphically in Chart 25. The dashed lines on the plot represent collected insolation values that are appropriate for central receiver concentrator systems at Inyokern and Sterling. For such a system at Inyokern, for example, in this Case C fuel scenario the value of C_{ar}/X for an array efficiency of 0.36 is about \$58/m²; thus if $X = 600$, the allowable array price is \$34,800/m². When these values are compared to the corresponding ones for a system with storage ($C_{ar}/X = \$25/\text{m}^2$) as determined from Chart 22, the economic disadvantage of the use of storage (at \$40/kWh or more) is again apparent.

Chart 25

Maximum Allowable Array Price for Photovoltaic Central Station Power Plant in Central Receiver Configuration - No Storage

FUEL PRICE CASE C
 $FL_0 = \$1.75/10^6 \text{ Btu}$
 POST-1990 FUEL ESCALATION
 RATE = 0.07

PHOTOVOLTAIC CENTRAL RECEIVER SYSTEMS OPTIONS

The results of the analyses discussed in connection with the preceding charts suggest that photovoltaic power plants employing concentrating collectors are unlikely to be competitive with coal-fired plants unless profitable use can be made of the large amounts of thermal energy that are also collected. It was therefore decided to make a preliminary investigation of the design characteristics and economics of photovoltaic plants in which the thermal energy is either sold as heat or used to generate electricity in a low-temperature "bottoming-cycle" turbine.

Since the value of thermal energy for either of the above uses increases with temperature, the most promising photovoltaic systems for this sort of combined operation are those using high-concentration collectors. The investigation therefore centered on systems using collectors in the central receiver configuration, as described in the text accompanying Chart 16. It was assumed that the exterior surface of the receiver is covered by AlGaAs/GaAs solar cells that are cooled by a flow of water in an annular channel on the inner side of the receiver surface. In the analyses that were carried out, the maximum

permissible temperature of any portion of the array was taken to be 200°C , based on manufacturer information indicating that higher array temperatures could reduce cell life.

The three different modes of operation that were compared in this preliminary study are listed in Chart 26. They are: (a) generate photovoltaic electric power (only) for sale (the case represented in the preceding charts in this report), (b) provide both photovoltaic electricity and thermal energy for sale, and (c) provide photovoltaic power and, by the addition of a low temperature turbine, use the thermal energy in the array coolant to generate additional electricity. In the first case, the system would be designed for maximum net photovoltaic power (power generated minus power consumed in pumping the coolant). In the second case, the design would again be optimized for maximum net photovoltaic power, but with the additional condition that the outlet water temperature would be high enough for the intended application of the thermal energy. In the third case, one would design for maximum net electric output, including the output of the bottoming cycle turbine.

Photovoltaic Central Receiver Systems

OPTIONS

- GENERATE PHOTOVOLTAIC POWER ONLY

DESIGN FOR MAXIMUM NET ELECTRICAL POWER (power generated - coolant pumping power), DUMP THERMAL ENERGY VIA DRY COOLING TOWER

- GENERATE PHOTOVOLTAIC POWER, SELL THERMAL ENERGY (PHOTOVOLTAIC/THERMAL)

DESIGN FOR MAXIMUM NET ELECTRICAL POWER, SELECT COOLANT CHANNEL GEOMETRY AND/OR VARY MASS FLOW FOR GIVEN CHANNEL GEOMETRY TO PROVIDE REQUIRED COOLANT MAXIMUM TEMPERATURES (65°C - 180°C feasible)

- GENERATE PHOTOVOLTAIC POWER, USE THERMAL ENERGY IN A BOTTOMING CYCLE (PHOTOVOLTAIC/THERMAL ELECTRIC)

DESIGN FOR MAXIMUM NET POWER (photovoltaic power + thermal electric power - coolant pumping power)

PHOTOVOLTAIC CENTRAL RECEIVER POWER PLANT: ARRAY COOLING REQUIREMENTS

The first step in the relative assessment of the three modes of generation shown in Chart 26 was to investigate the cooling system requirements. The configuration studied was one in which GaAs solar arrays were mounted on the exterior of a cylindrical central receiver mounted on top of a tower. It was assumed that the individual cells were coated on the rear with a layer of tin (to form the rear ohmic contact) and were attached by a thin layer of adhesive to the aluminum surface of the receiver. Array cooling was provided by a flow of water (inlet temperature, 20°C) in a narrow annular channel on the inner side of the receiver surface. The maximum temperature of any portion of the photovoltaic array was again limited to 200°C .

The results of the analysis, for the case where the insolation intensity at the array is 1 MW/m^2 , are displayed in Chart 27. There the net array efficiency (array output minus pumping power per unit of input power) is plotted as a function of water flow rate, per unit array area, for several different channel widths. Also shown is a plot of the outlet water temperature as a function of the same variables. These curves indicate that:

- a. With respect to net photovoltaic array output, there is an optimum flow rate for a given channel width. As the flow rate is decreased from the optimum, the average cell temperature increases, reducing cell efficiency, whereas increasing the flow rate beyond the optimum causes an increase in the pumping power that more than compensates for the improved cell efficiency caused by the decrease in cell temperature.
- b. As the channel width increases, the optimum flow rate also increases. The flow rate is proportional to the product of channel width and flow velocity; as the channel width is increased at a given flow rate, therefore, the flow velocity must decrease. The result is to reduce the pump power at a given flow rate or to allow higher flow rates for the same pump power. However, these higher flow rates do not greatly increase maximum net power because the heat transfer coefficient is also reduced by an increase in the channel width, leading to higher cell temperatures and lower cell efficiency at a given flow rate.
- c. At low flow rates, higher net power is achieved by reducing the channel width, whereas at high flow rates, higher net power is achieved by increasing the width. At low flow rates, net power is limited by high solar cell temperatures and corresponding low cell efficiencies. Reducing the channel width increases the heat transfer coefficient and reduces the cell temperature at a given flow rate. At high flow rates, net power is limited by the pump power; increasing the channel width reduces the pump power and provides higher net power.

The cooling system parameters for operation in either the Photovoltaic/Thermal or Photovoltaic/Thermal-Electric modes (Chart 26) are clearly those associated with the extreme left-hand side of Chart 27, where the water temperature is high. Optimum performance in either mode requires a trade-off of the reduced photovoltaic array efficiency against the improved thermal performance.

Photovoltaic Central Receiver Power Plant

ARRAY COOLING REQUIREMENTS

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PHOTOVOLTAIC CENTRAL RECEIVER POWER PLANT CHARACTERISTICS

The figures in Chart 28 display some of the principal characteristics of photovoltaic central receiver plants designed for the three different modes of operation that were discussed in the text accompanying Chart 26. These graphs present the results of calculations for the maximum-insolation case where the GaAs arrays are illuminated by sunlight with an intensity of 1 MW/m^2 .

The Photovoltaic-Only system represented by the graph on the left is designed to provide maximum photovoltaic power (power generated minus coolant pumping power), and the heat absorbed by the coolant is dumped to the atmosphere. Each point on the curve corresponds to a different width for the annular cooling channel (and therefore to a different system design) and represents system performance for optimum choices of operating parameters, particularly coolant flow rate. As the graph indicates, maximum system efficiency (the ratio of net electrical power to insolation on the array) occurs at an average array temperature of about 70°C and a maximum (outlet) coolant temperature in the neighborhood of 41°C . (This maximum point also corresponds to a channel width of 5 cm and a coolant flow rate of 120 gallons per minute per square meter of array.) As the average array temperature decreases, the channel width and coolant flow rate for maximum efficiency both increase, and eventually the increase in coolant pump power exceeds the increase in array electrical output.

The heat energy available in the coolant of a GaAs array is typically three to six times greater than the photovoltaic electrical energy and could potentially be sold to generate revenue. The middle figure of Chart 28 shows that the temperature of this heat energy may be varied significantly for a given system, without greatly changing electrical efficiency, by varying the coolant flow rate. For example, with a 1 cm coolant channel, dropping the flow rate from 50 to 25 gallons per minute per square meter of array would increase maximum water temperature from 70°C to 150°C with virtually no change in efficiency. Heat energy at these temperatures could be used for space heating and cooling or in various

industrial processes. A photovoltaic central receiver may therefore be operated to provide thermal energy at customer-specified temperatures (up to about 175°C) without significantly affecting electrical power generation.

Coolant heat energy may also be used to generate additional electricity by use of a turbine "bottoming cycle." The right-hand figure on Chart 28 shows system efficiency for a combined Photovoltaic/Thermal-Electric system as a function of average array temperature, where the turbine inlet temperature is assumed to be 14°C below the coolant maximum temperature. In this case an overall efficiency of $\sim 24\%$ can be achieved (photovoltaic plus thermal electric power generated minus coolant pumping power divided by insolation on the array). Such an efficiency occurs at an average array temperature of approximately 130°C , maximum water temperature of 167°C , coolant channel width of 0.6 cm, and a flow rate of 16.5 gallons per minute per square meter. Again, each point on the photovoltaic or combined photovoltaic and thermal electric curves corresponds to an optimum system design with specified values of channel width and flow rate. Points corresponding to larger channel widths also correspond to higher average array temperature in this graph. Thus, as one moves to the left in the figure, toward lower average array temperatures, the channel width decreases and the heat transfer coefficient rises. As a result, the temperature difference between cooling water and array decreases rapidly enough so that the water temperature can actually increase slightly even though the array temperature drops. Eventually, however, the increase in coolant pump power exceeds both the increase in photovoltaic power resulting from the lower average array temperature and the increase in thermal electric power resulting from the higher water temperature. The optimum design conditions for this combined Photovoltaic/Thermal-Electric system are in striking contrast to those for the Photovoltaic-Only system. These differences are summarized in the following table:

	<u>Photovoltaic/ Thermal- Electric</u>	<u>Photovoltaic Only</u>
Max. Array Temp., °C	200 (Assumed Limit)	81
Avg Array Temp., °C	130	70
Max. Water Temp., °C	167	41
Channel Width, cm	0.6	5.0
Flow Rate, gpm/m ²	16.5	120

Photovoltaic Central Receiver Power Plant Characteristics

Water cooled GaAs solar cells
 Maximum array temperature: 200°C
 Insolation on array: 1 MW/m²
 Water inlet temperature: 20°C

PHOTOVOLTAIC ONLY

PHOTOVOLTAIC / THERMAL

PHOTOVOLTAIC / THERMAL-ELECTRIC

PHOTOVOLTAIC CENTRAL RECEIVER POWER PLANT: PHOTOVOLTAIC/ THERMAL-ELECTRIC OPERATIONAL STRATEGIES

The graphs in the preceding two charts all represent system performance characteristics when the insolation reaching the array is 1 MW/m^2 . In order to get an idea of the manner in which plant performance will vary with season, time of day, or weather conditions, it is necessary to investigate the changes that occur when insolation is less than the maximum anticipated value. In the Photovoltaic-Only and Photovoltaic/Thermal options, the operational changes needed when insolation decreases are fairly straightforward, as are the effects on system output. In the Photovoltaic/Thermal-Electric case, the situation is more complex. At least three operational strategies can be defined:

- a. Maintain constant flow rate (16.5 gpm/m^2) and pump power and allow both the average array and maximum water temperatures to decrease.
- b. Maintain constant maximum water temperature (167°C) by reducing the flow rate and pump power to compensate for reduced insolation. Turbine inlet pressure is also reduced to maintain constant volume flow rate in the secondary loop of the heat exchanger.
- c. Maintain constant maximum array temperature (200°C) by reducing the flow rate and pump power to compensate for reduced

insolation. The required reduction in turbine inlet pressure is significantly greater in this case than in (b) above.

The results of preliminary calculations of these three strategies are shown in Chart 29. Of the three approaches, operation at constant coolant maximum temperature (center graph) appears to be the most desirable and results in essentially constant efficiency down to an array insolation of 0.4 MW/m^2 . This occurs primarily because photovoltaic efficiency improves slightly at lower insolation (lower average array temperature), while the thermal-electric efficiency remains essentially constant (constant turbine inlet temperature and only moderate reduction in inlet pressure). In the constant flow rate case (left-hand chart), the rapid drop in system efficiency is due primarily to the decrease in thermal-electric output resulting from reductions in maximum coolant temperature. This decrease far outweighs the improvement in photovoltaic efficiency that occurs because of reductions in average array temperature. When the system is operated at constant maximum array temperature (right-hand graph), the reduction in turbine efficiency as a result of reduced pressure more than compensates for the slight increase in turbine inlet temperature. This net reduction in turbine efficiency, in turn, more than compensates for the slight increase in array efficiency caused by the drop in average array temperature with decreasing insolation.

Photovoltaic Central Receiver Power Plant

PHOTOVOLTAIC/THERMAL ELECTRIC OPERATIONAL STRATEGIES

[Design point: 1 MW/m^2 of insolation on array]

INTERMEDIATE LOAD PHOTOVOLTAIC POWER PLANTS: COST COMPARISON

The results of the analyses discussed in connection with Charts 26-29 and the results of the computer simulations used in constructing Charts 16-19 have been used as the basis for a rough economic comparison of photovoltaic power plants in the central receiver configuration, operating in the three modes discussed. Also considered were plants using flat-plate collectors, for two array prices, \$100/kW_{pk} and \$500/kW_{pk}. To facilitate direct comparison, each of the plants was assumed to have a rated capacity of 100 MW, to be located at Inyokern, Calif., and to go on line in 1990. In each case, the design parameters were adjusted to yield the same plant capacity factor, 0.4, for operation at Inyokern, with 5 hours of electrical storage capacity included. In the Photovoltaic/Thermal-Electric case, since no allowance was made for thermal storage, the assumed mode of operation was one in which the turbine system continually generates all the electric energy it can produce and dispatches it into the grid. Photovoltaic output is used to bring the total plant output up to 100 MW, with the excess stored for later use. (This may not be the appropriate storage configuration for this system; simulation computations would be needed in order to determine the optimum combination of electrical and thermal storage.)

The first step in carrying out the comparison was to determine the total collector aperture area, for each type of plant and each mode of operation, that would result in the prescribed overall performance (PCF = 0.4). It was then a straightforward process to estimate the total plant cost in each case. The system

cost assumptions discussed in connection with Chart 16, supplemented by cost estimates of such additional elements as the low-pressure turbine for the Photovoltaic/Thermal-Electric system, were used in arriving at the total investment cost for each system, including the cost of conventional backup capacity. Levelized figures for the busbar cost of the output electric energy were then developed by the methodology described earlier (Chart 14). In the Photovoltaic/Thermal case, separate estimates were made of the revenue that would be generated if either 50% or 100% of the available thermal energy were sold (e.g., for district heating) at a net price of \$2/10⁶ Btu (after subtracting the costs of transmission and distribution). The levelized value of this thermal energy revenue was then deducted from the calculated busbar cost of electric energy to yield the net busbar charge for electric energy that is shown, along with the results of the other calculations, in Chart 30.

Although preliminary and approximate, the results shown in Chart 30 indicate that the profitable utilization of the thermal energy, in either of these two ways, would result in reductions in the net cost of electricity that appear to be sufficient to bring these energy costs into or near the competitive range. More definitive conclusions, however, would require much more refined analyses. It would be particularly useful to investigate the cost and performance of the bottoming-cycle turbine, the cost of storage and distribution of thermal energy, the appropriate mixes of electric and thermal storage, and the existence and nature of potential markets for the thermal energy.

Intermediate Load Photovoltaic Power Plants

COST COMPARISON

	PHOTOVOLTAIC FLAT PLATE		CENTRAL RECEIVER SYSTEMS			
			PHOTOVOLTAIC ALONE	PHOTOVOLTAIC THERMAL ELECTRIC	PHOTOVOLTAIC PLUS THERMAL 50% *	100% *
COLLECTOR AREA (m ²)	1.49(10 ⁶)	1.49(10 ⁶)	1.20(10 ⁶)	0.81(10 ⁶)	1.26(10 ⁶)	1.26(10 ⁶)
CONCENTRATION RATIO	1	1	600	600	600	600
CELL MATERIAL	Si	Si	GaAs	GaAs	GaAs	GaAs
STORAGE CAPACITY (kWh/kW _{rated})	5	5	5	5	5	5
1990 CAPITAL COSTS (\$/kW _{rated})						
COLLECTOR	226	226	720	486	756	756
ARRAY	201†	1006††	200	135	210	210
STORAGE	200	200	200	200	200	200
POWER CONDITIONING	70	70	70	70	70	70
BALANCE OF PLANT	56	56	111	109	114	114
TOTAL BASIC PLANT	753	1558	1301	1000	1350	1350
TOTAL PLANT (including spares, contingencies, interest during construction)	1149	2221	1883	1490	1948	1948
CAPITAL COST OF BACKUP CAPACITY	60	60	60	60	60	60
BUSBAR ENERGY COSTS (mills/kWh)						
ELECTRIC	55	101	86	69	66	43
THERMAL	--	--	--	--	23**	46**
PLANT CAPACITY FACTOR = 0.4						
GaAs ARRAY PRICE: \$10,000/m ²						
ALL COSTS IN 1975 DOLLARS						

* Fraction of heat sold at a net price (after distribution/storage cost) of \$2/10⁶ Btu

** Value of thermal energy assumed to escalate at 5% after 1990

† Array price = \$100/kW_{pk}

†† Array price = \$500/kW_{pk}

BREAK-EVEN ARRAY PRICE: ON-SITE RESIDENTIAL PHOTOVOLTAIC SYSTEM IN PHOENIX

The principal emphasis of the Task 2 efforts was on the central station power plant missions and, to a lesser extent, on total energy applications. However, some consideration was also given to residential on-site applications for photovoltaic electricity, in which photovoltaic arrays mounted on the roofs of individual single-family residences are used to serve the electric energy demands of the residence. No new detailed performance analyses (computer simulations) were carried out for the current study, but performance results obtained in the earlier Aerospace Corporation photovoltaic mission analysis project (Ref. 1) were used as inputs to a revised and extended economic analysis.

In the earlier study, the economic analysis consisted essentially of determinations of the total incremental present-value cost of providing electric service to a large number of single-family homes either (a) by means of on-site photovoltaic systems, backed up by the utility grid, or (b) directly from the grid. In either case, the capital cost of the required additional conventional generation capacity was included in the accounting. Based on a comparison of these costs, a determination was then made of the break-even array price, the price at which the total cost of the photovoltaic option is equal to that of the conventional alternative. This procedure had the advantage that it avoided all questions about who owned and operated the photovoltaic system or, indeed, about who would pay for any of the elements of the total cost of service. It had the disadvantage that it did not include in the accounting the effect of the cost of money on the annual cost of service or, more importantly, the effect of differences in the cost of the money used to defray different parts of the cost of service.

In the current study, this economic methodology was revised to take into account such differences. Each element (e. g., investment or O&M) of the total present-value cost of service was expressed in terms of an equivalent levelized stream of annual

costs, calculated in a manner analogous to that discussed in Chart 24 and in Ref. 2. The sum of these streams is then the total levelized annual cost of service, the constant annual amount that would pay all of the costs of meeting the postulated residential demand for 30 years, the presumed life of the photovoltaic systems. The calculation of the levelized annual value of each cost element is based on the cost of money to the payer responsible for that cost element and will depend, for example, on who is the owner of the physical property involved. The break-even array price of photovoltaic arrays is then determined as that array price at which the levelized annual cost of photovoltaic service (including conventional backup) is equal to the levelized annual cost of conventional service. Two different patterns of ownership were considered: (a) the photovoltaic system is owned and maintained by the homeowner, while backup energy is provided by the utility grid, (b) all generating equipment (including the photovoltaic systems) is owned and operated by the utility. The effective cost of money to the utility, the levelized fixed charge rate, was assumed to be 15% (corresponding to an after-tax discount rate of ~8%), while the homeowner's cost of money was assumed to be given by the capital recovery factor, 9.73%, corresponding to a mortgage interest rate of 9%.

In Chart 31 are displayed the results of applying this revised methodology to a set of examples that were examined in the earlier study. The curves illustrate the dependence of break-even array price on nominal system efficiency for the two different patterns of ownership and indicate that a substantial economic advantage is realized when the photovoltaic system is owned by the homeowner. The range of break-even array prices, for the three fuel price scenarios, is shifted from ~\$100-300/kW_{pk} (for utility ownership) to \$250-600/kW_{pk} (for homeowner ownership). This is principally due to the fact that a utility must pay dividends on equity capital and income taxes on the revenues generated in order to pay the dividends.

Breakeven Array Price

ON-SITE RESIDENTIAL PHOTOVOLTAIC SYSTEM IN PHOENIX

- ELECTRIC STORAGE: 8.2 hr AT AVERAGE POWER

		FL_0 (\$ / 10^6 Btu)	g
FUEL	CASE A	0.75	0.05
PRICE	CASE B	1.25	0.06
SCENARIOS	CASE C	1.75	0.07

- AEROSPACE SUBSYSTEM COST ESTIMATES
- BATTERIES AT \$40/kWh; POWER CONDITIONING AT \$100/kW

PHOTOVOLTAIC TOTAL ENERGY MISSION ANALYSIS

At best, only about 20% of the solar radiation that falls on a photovoltaic array is converted directly to electricity. Much of the remainder is absorbed as thermal energy that, in general, must be removed in order to keep array temperatures low enough to maintain photovoltaic conversion efficiency. If this thermal energy could be put to some productive use, it seems likely that its economic value would enhance the overall economic attractiveness of the use of photovoltaic arrays. An example of a system in which the thermal energy might be used to considerable economic advantage has, in fact, been discussed earlier in this report (Charts 26-30).

In Charts 32-39, a description is given of the initial phases of an investigation of a major class of applications in which the economic value of the thermal energy collected by a photovoltaic array is exploited: photovoltaic total energy systems (PTES). In these systems both photovoltaic electricity and the solar thermal energy collected by the array are used to meet all or part of the total thermal and electric load at a single load point or at a group of related load points. Since it is expected that this investigation will be continued in a follow-on project, some discussion of plans for later stages of the study are also included in this report.

The general methodology that has been selected for analyzing PTES missions is basically the same as that used in analyses of other solar energy missions, with some increased complexity to accommodate the addition of thermal supply and demand considerations. This procedure is illustrated in flow-diagram form in Chart 32. The first step, and the one to which much of the early effort has been applied, is to establish a data base, containing information about candidate types of applications (physical characteristics, geographic distribution, electric and thermal loads, estimated market size, etc.). In this phase of the effort, as many potential applications as possible are identified for preliminary scrutiny. The next step

is to develop and apply initial screening criteria to identify those candidates that are (a) technically feasible, (b) likely to be cost-effective in the post-1986 period, and (c) represent markets large enough to be significant in relation to the total energy consumption in the U.S. These criteria must, of course, include an assessment of the degree to which application requirements (especially the magnitude and timing of electrical and thermal demands) match the capabilities of PTES.

By the close of the report period, substantial progress had been made in the data search, some results of which are presented in Charts 33 and 34. When the data base is more nearly complete, it will be used in implementing the screening process to identify preferred applications for further analysis. The next step in the process, and the one on which by far the greater part of the future effort will be spent, will be the detailed analysis of the leading candidates that survive the initial screening. Computer simulation procedures will be used to evaluate the performance of the PTES systems in the application, as a function of system parameters, and the results will serve as inputs, along with system cost estimates, to an economic analysis that will determine the economic viability of the use of PTES in the application. Conversely, these economic analyses will also determine subsystem cost/performance goals that must be met if economic viability is to be achieved. During the current study period, in parallel with the work on data collection and initial screening, some effort was devoted to development of an initial "first-cut" simulation methodology and to preliminary computations of PTES performance in a single-family residential application. These efforts are described in Charts 35-39.

Photovoltaic Total Energy Mission Analysis

- RATIONALE: UTILIZATION OF WASTE HEAT MAY MAKE PHOTOVOLTAIC POWER COMPETITIVE AT HIGHER ARRAY COST

- APPROACH:

PHOTOVOLTAIC TOTAL ENERGY SYSTEMS: INDUSTRIAL PROCESS HEAT APPLICATIONS

The collection of the data base for the total energy mission analysis was begun with a brief review of those industrial applications for which information about thermal energy requirements was available from a variety of sources, including ERDA-sponsored surveys. Chart 33 summarizes the results of that review, for major industry groups, by tabulating the quantities of process heat energy consumed in 1970 at temperatures between about 50°C and 180°C. The higher temperature limit was set arbitrarily for the purpose of this initial review only and was based on the assumption that gallium arsenide arrays should not be operated at temperatures above 200°C. It is intended, in subsequent studies, to develop optimum temperature limits, which will be based on trade-offs involving the efficiency of energy conversion and system economics. However, as indicated on this chart, the temperature limits used were found to encompass about 66% of the industrial process steam and hot water requirements of the United States, and about 44% of the total process heat requirements. The latter category includes high temperature heat requirements (other than steam or hot water) of the metallurgical industry which cannot be met by photovoltaic total energy systems.

The largest industrial consumers of process heat are shown on this chart (except for the primary metals

group for the reason mentioned above). Because of the large variety of chemical processes, considerable effort will be required to screen out those processes in the Chemical and Allied Products section that have potential for photovoltaic total energy application and then to develop the thermal and electric load profiles that will be needed in order to perform more detailed analysis. It is expected that the Textile, Plastics, Rubber, etc., section will present similar problems.

The thermal-to-electric ratios shown on this chart represent only one of the screening criteria to be used in selecting applications for detailed analysis. Other criteria will include the match between insolation and load demand profiles, potential market size, geographic distribution, and so forth. Since hourly load profiles are generally not available in the literature, it is expected that the data base for this criterion will require considerable effort to develop and that direct contact with the industries concerned will be required. Except for batch processes, however, such profiles may be relatively easy to synthesize; in most continuous industrial processes, thermal energy requirements as well as electric power needs are relatively constant during operational periods.

Photovoltaic Total Energy Systems

INDUSTRIAL PROCESS HEAT APPLICATIONS

- ANNUAL TOTAL PROCESS HEAT REQUIREMENT $\sim 15 \times 10^{15}$ Btu (1970)
- ANNUAL TOTAL PROCESS STEAM AND HOT WATER REQUIREMENT $\sim 10 \times 10^{15}$ Btu (1970) - 20×10^{15} IN YEAR 2000

INDUSTRY GROUP	PROCESS HEAT AT $< 180^{\circ}\text{C}$, ANNUAL	THERMAL/ELECTRIC RATIO	COMMENTS
CHEMICAL & ALLIED PRODUCTS	600×10^{12} Btu	4	REQUIRES REVIEW OF HUNDREDS OF PROCESSES, MANY EXPECTED TO BE SUITABLE FOR PTES
PETROLEUM PRODUCTS	770×10^{12}	NA	HAVE OWN FUEL SOURCE FOR STEAM & POWER GENERATION, POOR PROSPECT
FOOD & KINDRED PRODUCTS	900×10^{12}	3	RELATIVELY POOR ENERGY RATIO FOR PTES
PAPER & ALLIED PRODUCTS	300×10^{12}	9	PTES APPEARS TO BE GOOD MATCH
TEXTILE, PLASTICS, RUBBER, etc.	4100×10^{12}	NA	INDIVIDUAL PRODUCT REVIEW MAY DISCLOSE MANY PTES APPLICATIONS
6.65×10^{15} Btu 44% OF TOTAL PROCESS HEAT REQUIREMENT			

- APPLICATION SCREENING PROBLEMS
 - FREQUENTLY ONLY ELECTRICAL OR THERMAL DEMAND AVAILABLE - NOT BOTH
 - LOAD PROFILES USUALLY NOT AVAILABLE FROM LITERATURE

CUMULATIVE DISTRIBUTION OF INDUSTRIAL PROCESS HEAT REQUIREMENTS

Whereas the previous chart showed industrial process heat requirements apportioned by industry group, Chart 34 depicts the cumulative distribution of process heat energy as a function of demand temperature level. The chart indicates clearly that the total market for industrial process heat that could be served by photovoltaic total energy systems increases very rapidly as the allowable array coolant temperature is raised from ambient to about 180°C. It also indicates that subsequent gains in fossil fuel displacement potential with increasing temperature are at a lower rate. It is important to stress that this chart only shows potential gain. The probability of achieving this gain has not yet been determined and will depend upon the outcome of detailed analyses designed to yield information on the cost of electrical and thermal energy from such systems and on the trades between such costs and operating array temperature.

Of particular interest on this chart is the regime between 125°C and 200°C, where about 60% of the process steam requirements of the U.S. are to be found. About 20% of these requirements are added to the potential photovoltaic total energy systems market for each of the steps from 125°C to 150°C, 150°C to 180°C, and 180°C to 200°C. This added potential would appear to provide strong incentive for the development of photovoltaic arrays with good efficiencies at such higher temperature levels, at least for industrial applications, as well as for the development of economical concentrator systems. As explained previously, the 180°C temperature limit for photovoltaic total energy systems indicated here is arbitrary and may be adjusted as a result of the more detailed analysis that is planned for the follow-on project.

Cumulative Distribution of Industrial Process Heat Requirements

RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY APPLICATION

It was decided at the outset of the investigation of PTES applications to conduct a preliminary examination of a selected application in parallel with the study procedure that was illustrated in Chart 32. The intended functions of this preliminary investigation were (a) to provide a focus (and test example) for the development of computer simulation procedures that will be needed for the analysis of PTES performance in the applications passed by the screening procedure and (b) to expose previously unrecognized technical and economic issues that must be considered in the screening procedure and in the detailed evaluation of the applications that survive the screening.

A photovoltaic total energy system to serve the electrical and thermal demands of a single-family residence was selected as the subject for this examination. This application was chosen largely because it appeared sufficiently promising to survive any likely screening procedure. The potential market clearly is enormous, and the match between the thermal/electrical demand and the thermal/electrical output of a PTES is fairly good and could be improved by judicious load management.

Chart 35 and the four following charts provide a summary description of the simulation and economic analysis procedures developed to investigate such systems and of some preliminary results for a single-family residence in Phoenix. It was assumed that this residence uses electricity for air conditioning and basic electrical loads (lights, appliances,

dryer, range) and thermal energy for domestic hot water and space heating. It was also assumed that backup thermal energy can be provided electrically by conventional generating systems and that all backup electrical energy is provided by the utility grid.

A schematic of the photovoltaic total energy system considered in the analysis is shown in Chart 35. The photovoltaic array consists of a water-cooled panel, which converts solar insolation to DC electricity and thermal energy, and a separate air-cooled panel, which provides only DC electricity. The electricity generated is either converted to AC and delivered directly to the electrical load, used to charge a storage battery, or dumped if the battery is fully charged. Thermal energy carried by the water is, in order of priority, used for space heating through a water-to-air heat exchange, used for domestic hot water heating through a water-to-water heat exchange, stored in a hot water tank, or dumped to the atmosphere if the water in the tank is already at a specified maximum temperature. When insolation is not capable of maintaining the temperature of the water in the thermal storage tank at or above a prescribed level, electrical resistance heating of the water is provided by backup power. Photovoltaic total energy system performance and costs are compared to the conventional alternative, which is assumed to be an all-electric home powered by the local utility. In computing the cost of service, it is assumed that the photovoltaic system is owned by the homeowner and financed under his mortgage.

Residential Photovoltaic Total Energy Application

Chart 35

RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY SYSTEMS SIMULATION

The residential PTES simulation approach is illustrated in Chart 36. The thermal simulation is conducted first. Hourly ambient temperature data are combined with space heating requirements, expressed as a function of ambient temperature, to develop the space heating thermal load profile. The space heating load combined with the hourly domestic hot water demand is defined as the total thermal load. With this load and the insolation data as inputs, an hour-by-hour simulation of the operation of the thermal portion of the photovoltaic total energy system is conducted for various input values of thermal collector area and thermal storage. The results of the simulation are used in an economic analysis to define the collector area and thermal storage level that result in satisfaction of the thermal demand at minimum annual cost, including the cost of backup energy. This optimum collector area is then also the area of the water-cooled portion of the photovoltaic array.

Analysis of the electrical portion of the system is conducted in a similar manner. Hour-by-hour temperature information is merged with air conditioning requirements to develop the air conditioning demand. The total residential electrical demand is the sum of the basic residential electrical load and the air conditioning demand. The electrical load and insolation data are used in an hour-by-hour simulation of the operation of the electrical portion of the system for various input values of storage capacity and photovoltaic array area. The array consists of a water-cooled, fixed temperature (i. e., fixed efficiency) photovoltaic/thermal panel, with area defined by the thermal simulation, and an air-cooled panel (with

varying efficiency). The results of the simulation are used in an economic analysis to define the combination of electrical storage and air-cooled panel area that minimizes the annual cost of satisfying the electrical demand. The results of the separate thermal and electrical simulations are then combined and used in a determination of the total annual cost of meeting the combined demand.

In view of the preliminary and exploratory nature of this residential PTES analysis, the procedures chosen for use in the economic evaluations have been simplified versions of the methods described in other sections of this report. The main simplifications have been in the computation of the costs associated with backup power from the utility grid and in the treatment of the cost of conventional power (as an alternative). In both of these cases, the cost of utility power has been expressed as a single parameter, a levelized cost for delivered electricity, expressed in mills/kWh (1975 dollars). (It will be recalled that backup thermal energy is provided in the form of electricity through a resistive heating element in the thermal storage tank.) Thus the complexities associated with margin analysis and the determination of precise backup capacity requirements and with calculations of the costs (fuel and O&M) of generating backup energy have been ignored. The difference between what a utility might charge for backup energy (coupling a requirement for maintaining standby energy-delivery capability with relatively small energy sales) and what it might charge for regular service is only dealt with in parametric fashion.

Residential Photovoltaic Total Energy Systems

SIMULATION/ANALYSIS APPROACH

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LEVELIZED ANNUAL COST OF THERMAL ENERGY

The results of the thermal portion of the analysis for a single-family home located in Phoenix are shown in Chart 37. The vertical axis represents the total levelized annual cost of meeting the full thermal demand of the residence; it therefore includes the cost of backup energy. The levelized annual cost of meeting this demand with utility power is represented by the horizontal line at \$520/year, corresponding to the cost of the estimated annual thermal demand (10,370 kWh) at an assumed unit cost to the homeowner of \$0.05/kWh. The various curves in Chart 37 illustrate the dependence of the total levelized annual cost of service on the area of the photovoltaic/thermal panel, for several thermal storage capacities and for various choices of the relevant economic parameters.

The most striking features of the curves in Chart 37 are the pronounced minima that are obtained in every case. These occur because, at small values of panel area, the incremental cost of increasing the panel area is smaller than the cost of backup energy. As the panel area becomes large, however, the incremental useful thermal energy provided becomes smaller (i.e., more is wasted) and eventually it becomes less expensive to purchase backup energy than to add panel area. The baseline case, represented by curve (1), corresponds to a case where 50 kWh of thermal storage is provided, the capital recovery factor is 0.09 (corresponding to a mortgage interest rate of slightly more than 8%), the panel cost is \$50/m², and backup energy can be obtained at a unit price of \$0.05/kWh. For this case, the optimum photovoltaic/thermal panel area is about 30 m² and the annual cost of thermal service is \$440, about \$80 less than the cost of meeting the entire demand with utility power at \$0.05/kWh.

The other curves in the chart display the effects of several types of variations from the baseline case:

- a. The effect of thermal storage level [compare curves (2) and (3) with (1)]. Reducing thermal storage from 50 kWh to 25 kWh makes

virtually no change in levelized annual cost. However, with no storage, the nominal system is no longer competitive with conventional power, and the optimum panel area drops to about 10 m².

- b. The effect of different rates for backup and conventional power. A utility may charge customers with photovoltaic/thermal systems a higher rate for backup power (to cover the costs of decreased utilization of existing generation, transmission, and distribution systems or for new capacity required for solar backup) than is charged customers who use only conventional power. Curve (4) shows the levelized annual costs that result when the rate charged for backup power is increased to \$0.06/kWh (a 20% increase over the assumed nominal cost of \$0.05/kWh). As Chart 37 shows, such an increase does not lead to results that are very different from those of the nominal case. As expected, the increase in backup costs makes a panel area slightly larger than the nominal more desirable and raises the minimum levelized annual cost. In practice, the levelized cost per kWh of backup power would likely be a function of the amount of backup power required.
- c. The effect of a higher value for the capital recovery factor, CRF (the effective cost of borrowed money). Curve (5) on Chart 37 shows levelized annual cost as a function of panel area for a CRF value of 0.10, a figure that is close to what a homeowner would pay with present mortgage rates since it corresponds to a mortgage rate of just over 9%. Again very little change from the nominal case is seen.
- d. The effect of increased panel costs. Curve (6) shows thermal system levelized annual costs for a system where the panel is

assumed to cost \$100/m² (approximately the present installed cost for thermal panels). The curve indicates that such a system would be almost competitive with conventional power at \$0.05/kWh.

Chart 37 shows that photovoltaic/thermal panel areas in the vicinity of 30 m² are optimum for many of the cases considered in this analysis. For the baseline case, about 75% of the annual thermal demand could be provided by the solar thermal system with a 30 m² panel. A larger fraction of the thermal

demand can be provided by the photovoltaic/thermal system, at increased annual cost, by going to larger panel areas. For example, with a panel area of approximately 55 m², the annual costs of solar thermal and conventional energy become equal, and the solar thermal system would meet about 83% of the thermal demand. In general, analysis indicates that efforts to reduce the backup power to small values (e.g., "all solar" homes) may be uneconomic.

Levelized Annual Cost of Thermal Energy

RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY SYSTEM

NOTES

LOCATION: PHOENIX
ANNUAL THERMAL DEMAND:
10,370 kWh
PRICE OF CONVENTIONAL
ELECTRICITY = \$0.05/kWh

- (1) BASELINE CASE:
COLLECTOR PANEL COST = \$50/ m^2
STORAGE CAPACITY = 50 kWh
CRF = 0.09
BACKUP ENERGY COST = \$0.05/kWh
- (2) BASELINE CASE EXCEPT
STORAGE = 25 kWh
- (3) BASELINE CASE EXCEPT
STORAGE = 0 kWh
- (4) BASELINE CASE EXCEPT BACKUP
ENERGY COST = \$0.06/kWh
- (5) BASELINE CASE EXCEPT CRF = 0.10
- (6) BASELINE CASE EXCEPT PANEL
COST = \$100/ m^2

LEVELIZED ANNUAL COST OF ELECTRIC ENERGY

Chart 38 presents the results of the electrical portion of the analysis of the same Phoenix residence that was represented in Chart 37. The total levelized annual cost of meeting the estimated electrical demand (17,440 kWh) is plotted as a function of the air-cooled photovoltaic panel area, A_e , for three levels of electrical storage. The photovoltaic array price was assumed to be \$100/kW_{pk} and the photovoltaic/thermal panel area was set at 30 m². The annual cost of meeting this demand with utility power is represented by the horizontal line at \$872/year, corresponding to the cost of providing 17,440 kWh at an assumed unit cost of \$0.05/kWh.

Chart 38 shows that for a given set of assumptions, there is an optimum air-cooled photovoltaic panel area that corresponds to the minimum levelized annual cost of satisfying the electrical demand. At small panel areas, the incremental cost of adding panel area is less than the cost of backup power saved, while at large panel areas the converse is true. In general, the system with minimum levelized annual cost requires significant levels of backup power, and the amount of backup power required

decreases with increasing levels of storage. For example, with no storage, the minimum cost system (30 m² air-cooled photovoltaic panel, in addition to the 30 m² of photovoltaic/thermal panel) provides only 40% of the annual electrical demand, while with 50 kWh storage, the minimum cost system (80 m² air-cooled photovoltaic panel) provides over 87% of the annual demand.

Of the storage levels shown in Chart 38, 25 kWh provides the lowest cost of electrical service. This occurs at an air-cooled panel area of approximately 75 m², and this system would provide about 83% of the electrical demand, including the electrical contribution of the 30 m² photovoltaic/thermal panel. Additional analyses indicate that as the photovoltaic array cost increases, the optimum air-cooled photovoltaic panel area decreases. For example, for a \$300/kW_{pk} array cost, the optimum air-cooled photovoltaic panel area is 20-40 m², which would provide 50-70% of the electrical demand. This result suggests an approach where initially small, expensive, photovoltaic panels are installed and then, as the cost of panels is reduced, more panel area is added, and a larger fraction of the electrical demand is provided by the PTES.

Levelized Annual Cost of Electric Energy

RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY SYSTEM

CHARACTERISTICS OF EXAMPLE OF RESIDENTIAL PTES IN 1900-2000 PERIOD

The PTES that provides electrical and thermal service at minimum total annual cost can be defined by combining the optimum thermal and electrical systems from Charts 37 and 38. The characteristics of such a combined system are summarized in Chart 39.

This chart shows that the residential PTES providing service at minimum total annual cost requires about 5500 kWh of conventional backup power, which is about 20% of the combined thermal and electrical demand. If the cost of conventional power were higher than assumed (\$0.05 kWh), minimum cost system would have larger panel area and require less backup energy, while the opposite would occur if the cost of conventional power were lower than assumed. In addition, although relatively optimistic assumptions were made with regard to the installed future costs of photovoltaic total energy systems (\$50/m² for the installed cost of the solar thermal panel and \$100/kW_{pk} photovoltaic arrays), the resulting first cost of such systems is not small (almost \$7300 in 1975 dollars), and the levelized annual savings over conventional power at \$0.05/kWh are not large (\$340 savings per year or 20% of the annual cost of conventional power).

Since the analysis of residential photovoltaic total energy systems that has been summarized in Charts 35-39 represents, at best, a first-cut look at this class of PTES applications, no final conclusions can be drawn from the results. With this caveat, however, one can infer from the analysis that:

- a. Minimum annual cost systems usually require significant levels of backup power. It may be uneconomic to provide 100% of the residential thermal and/or electrical demand with photovoltaic total energy systems.
- b. Except for systems having very small panel areas, systems with thermal and electrical storage have lower annual costs than systems without storage.
- c. It may be desirable initially to install small photovoltaic arrays and add array area as the cost of such arrays is reduced.

Characteristics of Example of Residential PTES in 1990-2000 Period

SINGLE-FAMILY PHOENIX RESIDENCE

TOTAL DEMAND (Thermal Plus Electrical) = 27,810 kWh

	SIZE	COST (\$)
<u>SOLAR THERMAL SYSTEM</u>		
PHOTOVOLTAIC/THERMAL PANEL	30 m ²	1500
THERMAL STORAGE	50 kWh	533
BALANCE OF PLANT		1000
CAPITAL COST		<u>\$3033</u>
FRACTION OF THERMAL DEMAND PROVIDED, 75%		
BACKUP ELECTRICAL POWER REQUIRED, 2592 kWh		
ANNUAL COST (CRF = 0.09, backup power at \$0.05/kWh, O&M = 1.5% of capital cost)		440
<u>SOLAR ELECTRIC SYSTEM</u>		
PHOTOVOLTAIC PANEL (air-cooled)	75 m ²	1418
PHOTOVOLTAIC/THERMAL PANEL	30 m ²	
ARRAY STRUCTURE	75 m ²	750
ELECTRICAL STORAGE	25 kWh	1000
POWER CONDITIONING	8 kW	800
WIRING/MISCELLANEOUS	pk	285
CAPITAL COST		<u>\$4253</u>
FRACTION OF ELECTRICAL DEMAND PROVIDED, 83%		
BACKUP ELECTRICAL POWER REQUIRED, 2964 kWh		
ANNUAL COST (CRF = 0.09, backup power at \$0.05/kWh, O&M = 6 mills/kWh)		610
TOTAL INCREMENTAL CAPITAL COST FOR PHOTOVOLTAIC TOTAL ENERGY SYSTEM		7286
TOTAL ANNUAL COST TO HOMEOWNER WITH PHOTOVOLTAIC TOTAL ENERGY SYSTEM		1050
TOTAL ANNUAL COST TO HOMEOWNER WITH CONVENTIONAL POWER (\$0.05/kWh)		1392
TOTAL ANNUAL SAVINGS TO HOMEOWNER WITH PHOTOVOLTAIC TOTAL ENERGY SYSTEM		342

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IV. TASKS 3-6. SUPPLEMENTARY STUDIES

This section contains a summary account of accomplishments in the remaining four tasks of the project. A fuller discussion of the work on these tasks is given in Volume IV, Supplementary Studies.

SUPPLEMENTARY STUDIES

Chart 40 contains a listing of the specific studies that were carried out under the four rather generally defined subordinate tasks of this project. The technical support to the Photovoltaic Program Planning Group, under Task 3, included a number of rather diverse activities: special ad hoc analyses, participation in Group deliberations, assistance in documenting Group recommendations and drafting plans, etc. These activities involved the joint efforts of individuals from a number of different organizations and have been reported in the written reports and presentations of the Program Planning Group, itself. They are not further discussed in this report.

Under Task 4, an investigation was made of the possible adverse impact that greatly increased production of silicon, CdS/Cu₂S, and GaAs solar arrays might have on the environment and on the health and safety of production workers and of the general population.

Under Task 5, a special Utility System Financial Planning Model, whose development was supported

by internal Aerospace Corporation funds, was adapted for use with photovoltaic central station power plants. The model was then used in a preliminary investigation of the impact of several different financial incentives on the economics of photovoltaic power plants.

Under Task 6, a preliminary study was made of the non-internalized societal costs (i.e., costs to society that are not reflected in the price of electricity) of coal-fired electric power generation. All elements of the generation process, from coal mine to dispersal of power plant effluents, were considered. It had originally been intended that this investigation cover other methods of power generation as well but, by mutual agreement between the ERDA Photovoltaic Program Office and The Aerospace Corporation, the effort was curtailed at about the mid-point of the project in order to shift project resources to provide greater support to the work on Task 2.

Supplementary Studies

TASK 3. REVIEW AND UPDATING OF ERDA TECHNOLOGY IMPLEMENTATION PLAN

- TECHNICAL SUPPORT TO PHOTOVOLTAIC PROGRAM PLANNING GROUP

TASK 4. CRITICAL EXTERNAL ISSUES

- EVALUATION OF ENVIRONMENTAL AND OCCUPATIONAL HAZARDS OF PHOTOVOLTAIC ARRAY PRODUCTION

TASK 5. THE IMPACT OF INCENTIVES

- EVALUATION OF THE EFFECT OF SELECTED FINANCIAL INCENTIVES ON THE ECONOMICS OF PHOTOVOLTAIC POWER PLANT OPERATION

TASK 6. THE SOCIETAL COSTS OF CONVENTIONAL POWER GENERATION

- EVALUATION OF THE NON-INTERNALIZED COSTS TO SOCIETY OF COAL-FIRED ELECTRIC POWER GENERATION

ENVIRONMENTAL AND OCCUPATIONAL HAZARDS OF PHOTOVOLTAIC ARRAY PRODUCTION

Little attention has yet been paid to the hazards to society that are associated with the manufacture and deployment of photovoltaic solar arrays, largely because the present production volume is minuscule in terms of the overall American economy. The current silicon array industry is dwarfed by the other elements of the silicon semiconductor industry, the cadmium sulfide array industry is in its infancy, and gallium arsenide array production is still in the research and development phase. If photovoltaic solar energy conversion is to play a significant role in the U.S. energy economy of the future, however, the rate of production of photovoltaic arrays (most likely one of the three types mentioned) will have to increase to a level tens or hundreds of thousands of times larger than the current production level for silicon arrays. In that event, any hazards associated with the production or deployment of arrays could have important national impact. For this reason, it was decided to conduct a preliminary investigation of these hazards as part of this project.

Chart 41 presents the objectives of the investigation, outlines its structure, and summarizes the conclusions reached. The study considered only three photovoltaic materials: silicon, cadmium sulfide (actually CdS/Cu₂S), and gallium arsenide (actually AlGaAs/GaAs). In assessing the relative hazards associated with these cell types, it was assumed that much larger quantities of Si or CdS/Cu₂S cells would be required than of AlGaAs/GaAs. The reason for this assumption is that it was judged that the first two cell types might well be used in flat-plate arrays, while the relatively high cost and scarcity of gallium would require that AlGaAs/GaAs cells be used with high-concentration solar collectors.

The investigation began with a survey of materials that are likely to be involved in manufacturing any of the three types of arrays. A large number of toxic or otherwise hazardous materials were identified, and many relatively dangerous process steps were recognized. In virtually every case, however, it was found that these materials have been and are being handled safely in the projected (or even much larger) quantities in currently operating chemical industries. It was tentatively concluded that, while precautions would be required, the current state-of-the-art in the chemical industry would probably permit all array manufacturing processes to be carried out without adversely impacting the environment or the health and safety of production workers or the general public to a significant extent.

It was also tentatively concluded that the large-scale deployment of silicon arrays would not pose a significant hazard. The situation is somewhat different with the other two types of cells. If the use of CdS/Cu₂S arrays in rooftop systems were to become widespread, a significant hazard would be posed to neighbors and, especially, fire fighters in the event of a building fire. Most cadmium compounds are quite toxic and combustion of the arrays could lead to the dispersal of such compounds, in dangerous concentrations, over fairly large areas. A similar problem would be posed by the widespread use of thin-film gallium arsenide cells in rooftop systems because of the toxicity of such arsenic compounds as As₂O₃. However, if gallium arsenide arrays are used only in high concentration systems as was assumed in this study, the potential danger to society is much smaller.

Environmental and Occupational Hazards of Photovoltaic Array Production

OBJECTIVE: TO EVALUATE THE HAZARDS TO THE ENVIRONMENT, TO PRODUCTION WORKERS, AND TO THE GENERAL POPULATION OF THE LARGE SCALE PRODUCTION OF Si, GaAs AND CdS/Cu₂S ARRAYS

TOPICS INVESTIGATED:

- HAZARDS AND ASSOCIATED PRECAUTIONARY MEASURES
 - RAW MATERIALS
 - STORAGE, HANDLING, TRANSPORT
 - SPILLS, LEAKS
 - FIRE, EXPLOSION
 - FINISHED PRODUCTS
 - GENERAL HAZARDS
 - FIRE, EXPLOSION
 - PROCESSES
- TOXICOLOGICAL AND PHYSIOLOGICAL RESPONSE DATA
 - RAW MATERIALS
 - FINISHED PRODUCTS

CONCLUSIONS:

- CHEMICAL INDUSTRY EXPERIENCE SHOULD PERMIT EVEN A GREATLY EXPANDED SOLAR CELL INDUSTRY TO CONDUCT ALL PROCESSING STEPS IN AN ENVIRONMENTALLY SOUND AND OCCUPATIONALLY SAFE MANNER
- WIDESPREAD DEPLOYMENT OF PHOTOVOLTAIC ARRAYS SHOULD NOT INTRODUCE SIGNIFICANT HAZARDS EXCEPT FOR THAT ASSOCIATED WITH ACCIDENTAL COMBUSTION OF CdS/Cu₂S ARRAYS

UTILITY SYSTEM FINANCIAL PLANNING MODEL

Even after it has been demonstrated that photovoltaic power plants can be competitive with alternative methods in terms of the life-cycle cost of energy production, it is unlikely that the first few conventional plants will be constructed under the impetus of conventional market forces alone. Some of the basic characteristics of these first plants — high technology, high risk (because the technology will be new), and high capital cost — can be expected to discourage investment. As a result, some form of governmental financial incentive may be necessary in order to stimulate their timely construction. For this reason a preliminary examination of alternative incentive strategies was included as part of the current project. This study is the subject of Charts 42 and 43.

The evaluation of the impact of incentives requires the use of a more complex economic analysis procedure than the levelized fixed charge approach that has been used, with adequate precision, in the other parts of this project. Fortunately, an analytical tool that was well suited to the incentives study had just been developed by The Aerospace Corporation, using internal corporate funds. This tool, the Utility System Financial Planning Model, is illustrated in block diagram form in Chart 42.

The Utility System Financial Planning Model treats cash flows, taxes, depreciation, working capital allocations, and allowed revenues in a manner that is consistent with the way in which power plant economics are viewed by such regulatory agencies as the Federal Power Commission. The central element of the model is the determination of the revenue stream that will be just sufficient to cover all costs and

provide an adequate return on the equity funds employed. This revenue determination is based on separate calculations of (a) total plant investment costs, (b) the rate base, the utility's net investment at a given time as determined in accordance with regulatory practice, (c) the allowable rate of return on rate base, (d) currently payable and deferred income taxes, and (e) all other expenses, including plant operation and maintenance costs, depreciation, interest on debt, and taxes. The total construction cost of the plant (including spares, contingencies, indirect costs), evaluated as of a selected base year, is one of the principal inputs, and the first step in the program is the escalation of these base year construction costs to current dollars and the computation of the allowance for funds used during construction (AFUDC), a quantity that includes interest during construction. The model also includes a provision for including the cost of periodic replacement of major plant subsystems that have a service life shorter than that of the plant itself (typically 30 years).

Among the outputs of the model are calculated values of a number of quantities that are useful in comparing the results of using the model with the corresponding results that would be obtained by using the levelized fixed charge approach. These outputs include: the total construction cost (including AFUDC) as of the first year of commercial operation; the levelized busbar energy cost; the annualized fixed charge rate; the capital recovery factor; the effective after-tax discount rate; the cumulative dividend payment rates for both preferred and common stock; the effective tax rate; and the interest coverage (the ratio of earnings, including AFUDC, to interest on debt plus amortization of debt expense).

Utility Financial Planning Model

Chart 42

IMPACT OF FINANCIAL INCENTIVES ON PHOTOVOLTAIC POWER PLANT ECONOMICS (SOME PRELIMINARY RESULTS)

The model described in the preceding chart was used in a preliminary evaluation of the impact of six selected incentive strategies on the economics of photovoltaic power plant operation. Each strategy was treated as a perturbation of a baseline case in which a 100 MW photovoltaic power plant (basic plant cost: \$1743/kW, in 1990 dollars) is assumed to go on line in 1990 and to operate at a plant capacity factor of 0.407. The debt/equity proportions for the baseline case were assumed to be: long-term debt, 55%; preferred stock, 18%; common stock, 27%. The interest rate was taken to be 9%, and the dividend rates for preferred and common stock were 9% and 15%, respectively. The baseline income tax rates used were: federal, 48%; state, 9%. An investment tax credit of 10% was assumed, applicable to 50% of taxes currently payable.

The following six incentive strategies were chosen for investigation:

1. Permitting a utility to treat interest during construction as a current expense (rather than as an addition to the investment cost) for rate making and tax purposes
2. Increasing the investment tax credit to 20%, applicable to 80% of taxes currently payable
3. Reducing federal and state income tax rates to 40% and 7.5%, respectively
4. Offering federal loan guarantees that permit realization of a 75/25 debt/equity financing ratio, an 8% interest rate, and preferred and common stock dividend rates of 8% and 14%
5. Operating under government ownership, leading to 100% debt financing, with an 8% interest rate and no income or other taxes
6. Utilizing incentives 1, 2, and 4 together

The effect on photovoltaic plant economics of applying each of these strategies is displayed in Chart 43. The values, for the baseline case, of the nine listed output quantities are shown in the column at the far right of the chart. The construction cost and energy cost values are expressed in 1975 dollars and 1975 mills/kWh, respectively. The numbers in the body of the table represent the percentage changes, from the baseline case values, in each of the listed output quantities, as a result of the various incentive strategies.

Of the six incentives that were considered, only those that increased the debt/equity ratio resulted in significant decreases in busbar energy cost. This result implies that federal loan guarantees might be the most effective way of improving the competitive position of photovoltaic power plants. It must be recognized, however, that investor-owned utilities may not be in a position to utilize such financing, because (a) existing bond covenants may place a maximum ceiling on bonded indebtedness, (b) stockholder approval may be required, or (c) a federally-guaranteed loan may restrict future financing.

The other incentives considered primarily impact the overall utility system's cash flow and earnings without significantly changing the busbar cost of energy. If photovoltaic plants were already economically competitive, however, such incentives might be the strategies of choice in persuading a utility to choose a photovoltaic plant in preference to an alternative that would otherwise be economically equivalent.

Impact of Financial Incentives on Photovoltaic Power Plant Economics (Some Preliminary Results)

	INCENTIVE STRATEGY	PERCENT INCREASE (decrease) FROM BASE CASE						BASE CASE TOTALS
		(1) IDC* TREATED AS OPER EXPENSE	(2) 20% INVEST TAX CREDIT	(3) 40% FEDERAL 7.5% STATE INCOME TAX	(4) 75/25 DEBT/EQUITY 8/8/14 INTEREST AND DIVIDEND RATES	(5) 100% DEBT 8% INTEREST NO TAXES	(6) INCENTIVES (1), (2), AND (4) TOGETHER	
TOTAL CONSTRUCTION COST		(7.2)	0	0	(2.7)	(5.7)	(11.5)	1027
LEVELIZED BUSBAR ENERGY COST		(6.0)	0	(4.5)	(25.0)	(42.4)	(31.8)	48
ANNUALIZED FIXED CHARGE RATE		(0.6)	0	(5.1)	(25.5)	(42.7)	(25.5)	15.7
CAPITAL RECOVERY FACTOR		0	0	0	(13.8)	(22.4)	(12.9)	11.6
AFTER-TAX DISCOUNT RATE		0	0	0	(16.2)	(26.1)	(15.3)	11.1
CUMULATIVE DIVIDEND PAYOUT RATE								
PREFERRED STOCK		(5.5)	1.4	11.0	(23.3)	--	(27.4)	7.3%
COMMON STOCK		(14.3)	10.2	4.1	(11.2)	--	(41.7)	9.8%
EFFECTIVE TAX RATE		4.5	(11.9)	(18.3)	(21.7)	--	(49.9)	47.1%
INTEREST COVERAGE		(9.1)	3.3	(3.0)	(51.5)	(69.7)	(48.5)	3.2

* Interest During Construction

SOCIETAL COSTS OF COAL-FIRED ELECTRIC POWER GENERATION SYSTEM

Any assessment of the full non-internalized social costs (i. e. , costs to society that are not included in the price of electricity) of coal-fired power generation must take into account the entire production cycle, including fuel production (mining), fuel transportation, and power generation. In Chart 44 are listed the principal sources of societal damage that are associated with each of these three elements of the coal-fired power generation system. Also shown are the main types of damage that occur. Some of the listed damages (e. g. , to property values and to health) can, in principle, be quantified in economic terms, (although there is considerable disagreement about the computed magnitudes). Other damages (e. g. , to mental health or to climate) are so uncertain, at least at present, that no economic quantification is possible.

In the present preliminary study, the extensive and varied literature on these different types of societal damage was reviewed with the objective of identifying the types of damage that contribute significantly to the total. A critical assessment was then made

of the available data about these significant damage elements and their total economic impact (in mills/kWh) was computed on the basis of the data that were judged to be most reliable. In these computations, it was assumed that the generation plants involved were in compliance with current federal law with respect to emissions. The resulting numbers, of course, are subject to appreciable uncertainty, largely because of their dependence (a) on long chains of assumptions linking original cause to resulting damage cost and (b) on the particular set of social priorities that are reflected in the unit cost assigned to each type of ultimate damage.

In this analysis, no attempt has been made to include the societal benefits (societal economies) that are associated with coal-fired power production. The purpose of this task is to provide a quantitative basis for comparison of the societal diseconomies that are associated with conventional coal-fired power plants and give necessary inputs to determine the appropriate size of federal incentives or subsidies that may be justifiable for photovoltaic power plants.

Societal Costs of Electric Power Production

COAL-FIRED GENERATION

Chart 44

FUEL PRODUCTION		FUEL TRANSPORTATION		POWER GENERATION	
DAMAGE SOURCE	SOCIETAL DAMAGE TO:	DAMAGE SOURCE	SOCIETAL DAMAGE TO:	DAMAGE SOURCE	SOCIETAL DAMAGE TO:
COAL DUST	PROPERTY VALUES	ACCIDENT	PEOPLE: INJURIES AND DEATHS	EMISSION OF: SO _x (sulfates)	PHYSICAL HEALTH
MINE WASTES	ROAD AND HIGHWAYS	OVERLOADING OF ROAD BEDS	INCREASED ROADBED MAINTENANCE	NO _x	MATERIALS
COAL DEBRIS	AGRICULTURE: ENVIRONMENT		PROPERTY DAMAGE	PARTICULATES	AESTHETICS
LAND DISTURBANCE	ANIMAL LIFE			METALLIC TRACE ELEMENTS	MENTAL HEALTH
UNDERGROUND DISTURBANCE	HUMAN LIFE			CO	CLIMATE
EXPOSURE TO POTENTIAL ACCIDENTS	HEALTH OF MINERS			POLYCYCLIC HC	DOMESTIC ANIMALS
	MINE-SITE COMMUNITIES				WILDLIFE, VEGETATION
	LAND (subsidence)				
	WATER SYSTEMS				

ESTIMATES OF PHYSICAL HEALTH DAMAGE AND ASSOCIATED SOCIAL COSTS
ATTRIBUTABLE TO INCREASE IN AVERAGE SUSPENDED SULFATES

Although the single most harmful aspect of the coal-fired electric power generation cycle appears to be SO_x emission, the principal damage is not produced directly by SO_x , but rather by the suspended particulate sulfates that result when SO_x is oxidized in the atmosphere. This conclusion is based, in part, on epidemiological studies that have indicated an association between ambient sulfate levels and various adverse effects on human health. The CHES (Community Health and Environmental Surveillance System) study (Ref. 6) also indicated that health effects seem to be more closely associated with suspended atmospheric sulfate than with exposure to other pollutants. The main types of measurable health damage that are believed to result from increased atmospheric sulfate concentrations are those listed in Chart 45.

Any attempt to compute the total amount of health damage resulting from suspended particulate sulfates, however, is complicated by the fact that there is no general agreement about the relationship between the dose (the quantity of sulfate inhaled or ingested) received by an individual or population and the response in the form of measurable damage to health. In most observational situations, there is uncertainty about the dose received by the exposed population. In addition, different studies have used quite different measures of response. In many cases also, other factors that influence the result have been present and it has not been possible to correct for

their effect. It has been shown, for example, that the dose-response relationship varies significantly with the characteristics (age, race, smoking habits, etc.) of the population involved. Finally, the basic mechanisms of biological reaction with suspended sulfate particles are not yet fully understood. It is believed that the broncho-constricting potency of particulate sulfates is related both to the physical properties of the particles (e.g., size) as well as to such chemical properties as the pH. The biological reactivity of the sulfate particles also appears to depend on ambient humidity, temperature, and the synergistic effects of the presence of other pollutants.

As a result of these uncertainties, the National Academy of Sciences (Ref. 7) has supported the use of relatively simple dose-response relationships that should be approximately correct for a "typical" population. (See Table 12 in Volume IV of this report.) These relations were used in the computation of the damage figures shown in Chart 45. The second column lists the baseline statistics for the indicated types of health damage in a northeastern U.S. urban population of 10 million people exposed to an average atmospheric sulfate concentration of $16 \mu\text{g}/\text{m}^3$. The third column gives the annual amount of additional damage that would be expected if the concentration were increased by $1 \mu\text{g}/\text{m}^3$. These incremental damage figures were translated into the cost figures in the fourth column on the basis of unit cost figures that were also suggested by the National Academy of Sciences (Ref. 7).

Estimates of Physical Health Damage and Associated Social Costs Attributable to Increase in Average Suspended Sulfates

NORTHEASTERN U.S. METROPOLITAN AREA OF 10 MILLION POPULATION

BASELINE STATISTICS*	TOTAL NUMBER OF CASES*	ADDITIONAL EXPECTED CASES AT AVERAGE CONCENTRATION** INCREASE OF $+1\mu\text{g}/\text{m}^3$	ADDITIONAL SOCIAL HEALTH COSTS AT AVERAGE CONCENTRATION** INCREASE OF $+1\mu\text{g}/\text{m}^3$ (million \$)
MORTALITY RATE (deaths per year)	102.6×10^3	20	0.60
AGGRAVATED HEART-LUNG DISEASE SYMPTOMS (person-days of sickness per year)	21.2×10^6	350×10^3	7.04
ASTHMATIC ATTACKS (cases per year)	2.18×10^6	70×10^3	0.70
LOWER RESPIRATORY DISEASE IN CHILDREN (cases per year)	110×10^3	8.5×10^3	0.64
CHRONIC RESPIRATORY DISEASE (cases per year)	318×10^3	35×10^3	8.83
TOTAL SOCIAL HEALTH COSTS			17.80

*Data from the Statistical Abstracts of the U. S., 1970

**Assumes average annual concentration of $16\mu\text{g}/\text{m}^3$

YEARLY HEALTH DAMAGE RESULTING FROM SO_x EMISSIONS FROM 1000 MW_e URBAN AND RURAL COAL-FIRED POWER PLANTS

In Chart 46 are the results of a calculation of the total annual societal cost associated with health damage resulting from SC_x emissions from two typical 1000 MW coal-fired power plants. One of the plants is assumed to be an urban one, located 60 km from a population center like New York City; the other is rural, located 500 km from a region like the northeast corridor of the U.S. Both plants are assumed to be meeting the emission standards set by the New Source Standards of the Clean Air Act, which limits hourly emission of SO_x to 12,000 pounds. This assumption is equivalent to the adoption of either of two possible scenarios: (a) the plant burns coal with a 0.75% sulfur content and does not use flue gas desulfurization, or (b) the plant burns coal with 3% sulfur but uses desulfurization equipment capable of reducing SO_x concentration in the flue gas by 75%.

In order to estimate the total amount of health damage resulting from operation of these two plants, it is necessary first to determine the size of the population at risk and the increase in the ambient concentration of sulfate particles as a result of plant operation. The calculation of these two parameters involves

assumptions about (a) the dispersion behavior that governs the distribution of the emitted SO_x downwind from the plant, (b) the rates at which SO_x is oxidized to sulfate in rural and urban air, and (c) deposition rates (wet and dry) for both SO_x and sulfate particles. The resulting numbers are shown in the upper portion of Chart 46. A much larger population is put at risk by the rural plant because the dispersed plume covers a much larger populated area before blowing out to sea, but the ambient sulfate concentration is much smaller. The figures for SO_2 concentration shown in Chart 46 have no direct bearing on health damage but are important in computations of damage to materials.

The figures for annual health damage and the associated costs, in the bottom portion of Chart 46, are based on the results presented in the preceding chart (Chart 45), corrected to account for differences in the size of the exposed population and in the ambient sulfate concentration. (It was assumed that the health damage increases linearly with sulfate concentration over the narrow range involved in these calculations.) The translation of total cost into a cost per kWh was based on the assumption that the 1000 MW power plant in question operated with an annual capacity factor of 0.8.

Yearly Health Damage Resulting From SO_x Emissions From 1000 MWe Urban and Rural Coal Fired Power Plants

	URBAN PLANT		RURAL PLANT	
POPULATION AT RISK	11.5 MILLION		50 MILLION	
INCREASE IN AVERAGE ANNUAL CONCENTRATION OF SULFATE	0.75 $\mu\text{g}/\text{m}^3$		0.0585 $\mu\text{g}/\text{m}^3$	
INCREASE IN AVERAGE ANNUAL CONCENTRATION OF SO ₂	3.024 $\mu\text{g}/\text{m}^3$		0.141 $\mu\text{g}/\text{m}^3$	
	HEALTH DAMAGE PER YEAR	DAMAGE COST (\$10 ⁶)	HEALTH DAMAGE PER YEAR	DAMAGE COST (\$10 ⁶)
EXCESS PREMATURE DEATHS	17	0.51	6	0.18
AGGRAVATION OF HEART-LUNG DISEASE SYMPTOMS (person- days)	300,000	6.08	100,000	2.06
ASTHMATIC ATTACKS (cases)	60,000	0.63	21,000	0.21
LOWER RESPIRATORY DISEASE IN CHILDREN (cases)	7,300	0.56	2,500	0.19
CHRONIC RESPIRATORY DISEASE (cases)	30,000	7.65	10,000	2.58
TOTAL DAMAGE		15.43		5.22
HEALTH DAMAGE COST PER POUND OF SULFUR EMITTED		\$0.37/lb		\$0.12/lb
HEALTH DAMAGE COST PER kWh		2.2 mills/kWh		0.75 mills/kWh

EXPECTED SOCIETAL COSTS FOR COAL-FIRED POWER PLANTS

Calculations similar in basic philosophy to those illustrated in the preceding two charts were carried out for the other significant types of societal damage produced by coal-fired power generation. The results of these computations are summarized in Chart 47, and are expressed in mills per kWh of electric energy produced.

In calculating the costs associated with the power generation portion of the cycle, three different approaches were taken. The figures in the first column, the "national average" case, are based on data generated by the Environmental Protection Agency on the total costs to society of various types of air pollution. From the EPA figures for the total national costs resulting yearly from various types of pollution and for the total annual emissions of the pollutants, values were obtained for the social cost per pound of pollutant, for each pollutant type. The next step was to determine the amount of each pollutant emitted, on a per kWh basis, by coal-fired plants that meet the New Source Performance Standards of the Clean Air Act. The product, for each pollutant type, of the social cost (in dollars per pound) and the emission rate (in pounds per kWh) then represents a (rough) national average figure for the social cost (in dollars per kWh) resulting from emission of the pollutant in question by coal-fired power plants meeting current federal standards.

The figures in the second and third columns of the chart, representing typical rural and urban plants, are based on the models that have been described in connection with Chart 46. The same sort of computational procedure was employed, involving estimates of pollutant emission, the population and materials at risk, dispersion behavior, exposure behavior, damage behavior (e.g., dose-response relations), and unit costs for the various types of damage. The costs associated with each type of pollutant include costs resulting from property damage as well as from damage to health. (It is for this reason that the SO_x cost figures in Chart 47 exceed those in Chart 46.)

The societal costs resulting from the coal production and coal transportation elements of the cycle are, of course, the same in all three columns of Chart 47. The coal production costs have been separated into two categories: (a) health and welfare costs, primarily resulting from black lung disease of miners, deaths and injuries in mine accidents, general health degradation among miners, and the costs of rehabilitating mine-site communities as mines shut down, and (b) costs associated with damage to the environment, as a result of lowered property values, diminished recreational values (surface mines), land subsidence (underground mines), acid mine drainage, costs of disposal of mine wastes, and costs of land reclamation (surface mines). The societal costs of the coal transportation part of the cycle are almost entirely due to deaths and injuries in rail accidents.

It should be emphasized that the total societal costs shown in Chart 47 represent merely the "out-of-pocket" costs resulting from damage to health and property. They do not include, for example, the incremental amount a person would be willing to pay to avoid illness, injury, or death, and they do not include costs associated with damage that cannot be quantified in economic terms. Furthermore, it should be recognized that the costs are unevenly distributed over the population; the burden is mainly borne by the three groups identified in the chart. Finally, as has been mentioned above, the quoted cost figures are based on the assumption that there is (or will be) essentially total compliance with existing federal laws with respect to air pollution and to elimination of health and safety hazards. It is estimated that before these laws were in force the total societal costs of coal-fired power production were from 2 to 3 times greater than the totals shown in Chart 47.

Expected Societal Costs for Coal-Fired Power Generation Cycle

POWER GENERATION FUEL CYCLE ELEMENT	SOCIETAL COSTS (mills/kWh)		
	NATIONAL AVERAGE	TYPICAL RURAL PLANT	TYPICAL URBAN PLANT
FUEL PRODUCTION			
HEALTH AND WELFARE	0.55	0.55	0.55
ENVIRONMENT	0.96	0.96	0.96
SUBTOTAL	1.51	1.51	1.51
FUEL TRANSPORTATION	0.13	0.13	0.13
POWER GENERATION			
SO ₂ EMISSIONS	2.55	1.20	3.05
NO _x EMISSIONS	0.23	0.13	0.33
PARTICULATES	0.17	0.10	0.25
SUBTOTAL	2.95	1.63	3.63
TOTAL COSTS	4.59	3.27	5.27

- Societal damages are unevenly divided; especially affected are:
 - Personnel and families working in the power plant fuel cycle
 - Families who choose or are obliged to live in the pollution area
 - Children and the elderly and physically weak who do not have strong resistance against disease
- Before compliance with the Federal Coal Health and Safety Act and the New Source Performance Standards of the Clean Air Act, societal costs were 2 to 3 times the present and expected future costs

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V. RESULTS, CONCLUSIONS, AND RECOMMENDATIONS

This section contains two charts, one listing the principal quantitative results of the project and the conclusions that have been drawn from them, and the other presenting some recommendations to the ERDA Photovoltaic Program.

PRINCIPAL RESULTS/CONCLUSIONS

The more significant quantitative results of the project and some of the conclusions that can be drawn from these results are summarized in Chart 48.

Principal Results/Conclusions

- CUMULATIVE U. S. CIVILIAN PHOTOVOLTAIC MARKET IN 21 PROMISING GROUPS OF APPLICATIONS ESTIMATED TO BE 62 MW_{pk} THROUGH 1985, WITH PROJECTED 1985 SALES OF 13.3 MW_{pk}/year
 - AN ADDITIONAL 29 APPLICATIONS GROUPS APPEAR PROMISING, COULD INCREASE TOTAL 1985 SALES TO ~ 25 MW_{pk}/year, OR MORE
 - FOREIGN MARKETS AND U.S. MILITARY MARKETS WILL GENERATE SUBSTANTIAL ADDITIONAL SALES
- FLAT-PLATE PHOTOVOLTAIC POWER PLANTS FOUND COST-COMPETITIVE IN THE U.S. SUNBELT AT ARRAY PRICES IN THE \$100-200/kW_{pk} RANGE
- PHOTOVOLTAIC POWER PLANTS WITH CONCENTRATING COLLECTORS ALSO FOUND ECONOMICALLY ATTRACTIVE IF THERMAL ENERGY CAN BE PUT TO PROFITABLE USE
- PHOTOVOLTAIC POWER PLANTS WITHOUT ELECTRIC STORAGE FOUND MORE COST EFFECTIVE THAN PLANTS WITH STORAGE IF CAPITAL COST OF STORAGE (including replacements) IS ~ \$40/kWh OR GREATER
- BREAKEVEN ARRAY PRICES FOR ON-SITE RESIDENTIAL PHOTOVOLTAIC SYSTEMS ESTIMATED TO BE IN \$250-600/kW_{pk} RANGE IF SYSTEM IS OWNED BY HOMEOWNER, AND IN THE \$100-300/kW_{pk} RANGE IF SYSTEM IS OWNED BY UTILITY
- SUBSTANTIAL FRACTION OF U.S. INDUSTRIAL PROCESS HEAT APPLICATIONS FOUND TO REQUIRE TEMPERATURE LESS THAN 180°C AND THUS TO BE COMPATIBLE WITH GaAs ARRAYS
- RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY SYSTEM PROVIDING SERVICE AT MINIMUM COST FOUND TO REQUIRE SUBSTANTIAL (20% or more) CONVENTIONAL BACKUP
- ENVIRONMENTAL AND OCCUPATIONAL HAZARDS ASSOCIATED WITH ARRAY PRODUCTION AND DEPLOYMENT JUDGED AMENABLE TO CONTROL BY RELATIVELY STANDARD CHEMICAL INDUSTRY PROCEDURES, THE HAZARD OF ACCIDENTAL COMBUSTION OF CdS/Cu₂S ARRAYS A POSSIBLE EXCEPTION
- NON-INTERNALIZED SOCIETAL COST OF COAL-FIRED ELECTRIC POWER GENERATION ESTIMATED TO BE ~ 5 MILLS/kWh

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RECOMMENDATIONS

Chart 49 contains a listing of possible activities in the ERDA Photovoltaic Program that are recommended on the basis of information uncovered by the current study, of study results, or of recognition of gaps in the study coverage. The bases for the listed recommendations are, respectively:

- a. The near-term market survey carried out under Task 1 considered only non-military applications in the United States. The military and foreign markets are likely to be substantial and need to be evaluated quantitatively in order that their impact on the ERDA program can be assessed. In the case of the foreign markets it is expected that the requisite assessment will be included among the results of two ERDA-sponsored market studies initiated early in 1977 by InterTechnology Corporation and BDM Corporation. Another survey now being completed by BDM Corporation, under the direction of the U.S. Army Mobility Equipment Research and Development Command and supported by the Federal Energy Administration, may provide the needed information about U.S. military markets. If these current studies do not produce the desired information, more specific surveys of these two market areas would be in order.
- b. In the course of the survey of near-term markets, interviews with potential array-users revealed a general concern about the absence of accepted performance or service life standards for photovoltaic arrays or for such critical subsystems as the power conditioning assembly. The development of such standards, and of the associated testing procedures, would speed the acceptance of the technology by potential users.
- c. The current study provided additional support to the conclusion that array prices in the \$100-200/kW_{pk} range are needed in order to make flat-plate photovoltaic power plants competitive. It is therefore appropriate that the ERDA Photovoltaic Program continue to press for its 1986 goal of demonstrating the feasibility of producing arrays with prices in the \$100-300/kW_{pk} range.
- d. The investigation of major mid-term missions in the current study was concentrated mainly on central station power applications, although a small amount of attention was given to residential on-site (purely electrical) applications. Load-point applications for photovoltaic systems in the intermediate-to-large size range, i.e., greater than ~100 kW_{pk}, have not been studied adequately, and no really attractive applications in this class have yet been identified in The Aerospace Corporation mission analyses or in related studies by other contractors. An intensive effort to identify and evaluate such applications in the commercial, institutional, industrial, or agricultural sectors would be of value to the ERDA Photovoltaic Program.
- e. The investigation of the profitable use of the thermal energy collected in a high concentration photovoltaic power plant, though limited and approximate, indicated that this is an attractive concept. In order to draw more definitive conclusions, however, more refined analyses are clearly in order. It would be particularly useful to investigate the cost and performance of bottoming-cycle turbines, the appropriate mixes of thermal and electrical storage, and the existence and nature of potential markets for the thermal energy.
- f. Operation of high-concentration systems in which the thermal energy is put to profitable use puts a high premium on photovoltaic cells capable of operating at high temperatures without sacrificing service life. In addition,

the initial work on industrial PTES applications in the current study showed that a large fraction of industrial process heat is used at temperatures of up to 180°C. In either case, cells capable of long service life and relatively high efficiency at 200°C or more would be required.

- g. Because the industrial process heat applications mentioned above appear to represent an important potential PTES market, studies to identify the most promising applications and to define the appropriate system concepts would be desirable.
- h. The study of photovoltaic total energy systems in the current project constituted only a beginning. This study should be continued and extended to cover the full range of potentially attractive applications in the residential, commercial, institutional, industrial, and agricultural sectors. It should also consider such issues as the impact on the utility grid

of the requirement to provide backup for such photovoltaic total energy systems and the impact on the economics of the application of any demand charges or standby charges that might be imposed.

- i. The evaluation of the impact of incentives carried out in the current project was also limited in scope, considering only a restricted group of incentives and evaluating their impact only on the economics of photovoltaic central stations plants. The investigation should be extended to cover other incentive strategies — in particular, incentives developed to encourage the deployment of dispersed or on-site systems, under various patterns of ownership.
- j. The study of the societal costs of conventional power generation considered only coal-fired generation plants. Extension to other types of plants, especially nuclear fission reactors, including breeders, and perhaps such future possibilities as fusion reactors, would appear to be a useful activity.

Recommendations

- SURVEY MARKET FOR PHOTOVOLTAIC ARRAYS IN U.S. MILITARY AND FOREIGN APPLICATIONS (especially in less developed countries)
- DEVELOP STANDARDS FOR PERFORMANCE AND SERVICE LIFE OF ARRAYS AND OTHER CRITICAL SUBSYSTEMS
- MAINTAIN ERDA PHOTOVOLTAIC PROGRAM THRUST TOWARD ARRAY TECHNOLOGIES (e.g., thin film) WITH POTENTIAL TO REACH \$100-200/kW_{pk} PRICE
- INVESTIGATE NON-RESIDENTIAL (e.g., commercial, institutional, industrial, agricultural) ON-SITE APPLICATIONS, ESPECIALLY FOR USER-OWNED SYSTEMS
- MAKE MORE REFINED ANALYSIS OF THE PROFITABLE USE OF THERMAL ENERGY IN HIGH-CONCENTRATION PHOTOVOLTAIC POWER PLANTS; INCLUDE SUCH PLANTS AS PROGRAM OPTION
- ENCOURAGE DEVELOPMENT OF ARRAYS CAPABLE OF LONG SERVICE LIFE AT 200°C OR ABOVE
- IDENTIFY PREFERRED INDUSTRIAL PTES APPLICATIONS; CONDUCT CONCEPTUAL DESIGN STUDIES AND SYSTEM ANALYSES
- EXPLORE RESIDENTIAL/COMMERCIAL/INSTITUTIONAL/AGRICULTURAL PTES APPLICATIONS, IDENTIFY MOST PROMISING APPLICATIONS
- INVESTIGATE EFFECT OF EXPANDED RANGE OF INCENTIVES, WITH EMPHASIS ON INCENTIVES FOR DEPLOYMENT OF USER-OWNED SYSTEMS
- EVALUATE NON-INTERNALIZED COSTS OF NUCLEAR FISSION POWER (conventional or breeder) AND OF FUSION POWER

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