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Solar Thermal Power Systems
Point-Focusing
Thermal and Electric Applications Project

Perspectives on the Dispersed Application of Solar Thermal Energy Technology

Volume II: Working Papers on Technological, Economic and Solar Resources Issues

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Prepared for
U.S. Department of Energy
Through an agreement with
National Aeronautics and Space Administration
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ABSTRACT

This report presents an overview of the technological, economic, and institutional issues which affect the development and market acceptance of dispersed solar thermal power. System concepts and components currently under study are surveyed. Trends in national energy demand and supply are examined and the implications of these trends for dispersed power systems are evaluated. Financial factors which affect the user cost of solar power and market penetration are explored; more detailed quantitative analysis will be available in future documents. Regional variations of the solar resource are discussed and a research agenda is compiled for dispersed solar thermal systems.

FOREWORD

This report is organized into three volumes: Volume I - Executive Summary; Volume II - Working Papers on Technical, Economic and Solar Resources Issues, presented herein; and Volume III - Working Papers on Commercialization and Industrialization. These working papers provide an overview of the issues and problems of solar thermal technology development and application. Several of the papers are intended to inform the public and energy policy-makers about the general principles of solar thermal energy production and to define the economic, political and institutional problems that must be solved in order to exploit the solar thermal resource. Other technical papers address the analytical problems that must be solved in order to provide better information for decision-making regarding the development and use of solar thermal energy.

These working papers represent the status of work in progress. They initiate a research effort to improve the methods used to predict and evaluate the resources, costs, markets, and impacts associated with solar thermal energy. This information is important because the viability of solar power is contingent not only upon the development of new hardware, but also upon knowledge of the complex interactions between supply and demand for this new technology.

This report also indicates the need for social and scientific analyses of solar power issues in order to reduce the uncertainty that presently exists throughout the research, development, and demonstration processes. This report identifies the problems and issues confronting solar thermal energy today. This is the first step in the successful development of solar thermal technology.

ACKNOWLEDGMENTS

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SECTION I

INTRODUCTION

A. PURPOSE OF REPORT

Rapidly rising energy prices and diminishing availability of traditional fuels have stimulated a search for alternative energy sources. One of these alternatives may be dispersed solar thermal power, which can provide high temperature (160° C to 1400° C), environmentally clean heat in a wide variety of applications. However, there are a number of issues that must be resolved before solar thermal power becomes a fully developed alternative with commercial viability. Technological innovations and component cost reductions will enhance the competitive potential of solar thermal systems, but there are many other issues that affect the development and market acceptance of solar energy.

This report examines some of the issues that impact the competitive and commercial potential of solar thermal power, and suggests research programs and policies which may resolve these issues. It surveys the problems that succeeding reports will analyze in greater detail, with the ultimate objective of creating guidelines for technology development.

These working papers represent work in progress. Issues have been identified, and methods for analyzing them have been developed or proposed. Future reports in this series will address the economic and social costs and benefits of dispersed applications of solar thermal energy. The research plan calls for a three-part approach. These working papers represent the first phase of problem definition and conceptualization. The next two analytical phases are illustrated in Figure 1-1. The objective of the second phase is to improve the cost comparability of solar thermal applications; studies will focus on the technological and financial problems involved in making solar thermal energy a viable alternative. Cost comparisons of various solar thermal systems will be made in specific application settings. Cost comparability does not guarantee market acceptance. Therefore, the final phase of this research will explore the factors which affect market potential once solar energy is assumed to be a viable alternative. Then it will be possible to derive estimates of solar thermal energy's commercial potential and to evaluate the influence of policies and events on this potential. This information will be needed to set research, design and development priorities and to determine solar thermal development policies.

This document initiates a research effort directed toward resolving the problems facing solar thermal energy development. Each section focuses on a subset of issues, surveying the work that has been done to date, and outlining areas where additional research is necessary.

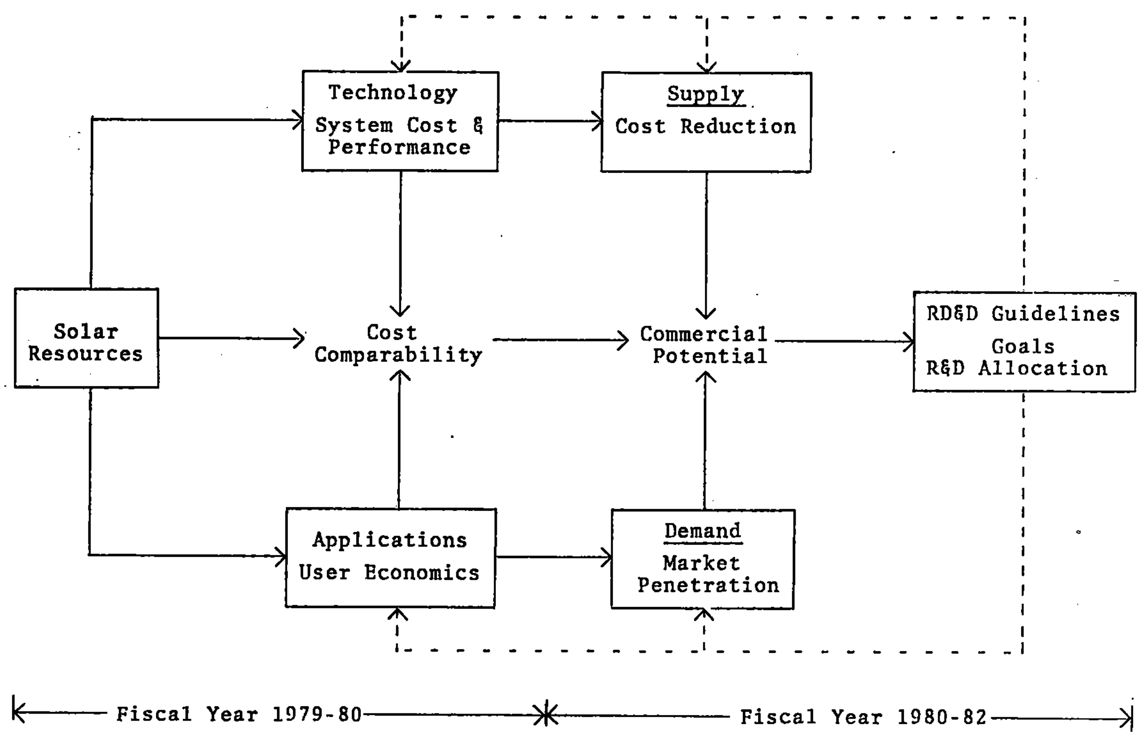


Figure 1-1. Overview of Solar Thermal Applications Research

B. OVERVIEW

Sections II and III of this volume overview the solar thermal technologies currently under study. Section II contains a general description of the various components and system concepts, and includes information on current cost and performance estimates. After identifying areas that have the greatest potential for cost reduction, Section III ends with a discussion of the cost reduction issues and problems facing solar thermal technologies.

To assess the potential usefulness of these solar technologies, it is necessary to evaluate energy needs and outputs during the period that solar power is being developed and tested. Section IV examines trends in national energy demand and supply; then evaluates the implications of these trends for the energy supply sector, environment, capital costs, and economy. The analysis then focuses on areas with the greatest promise for solar thermal users, and the advantages and disadvantages of dispersed power systems in each area. The final decision to invest in solar capacity depends on a large number of unresolved problems: cost of solar power and its alternatives, financial environment, institutional incentives, regulations, informational problems, market biases, and uncertainty. Each of these issues is discussed, and a final subsection outlines areas for further study.

Sections V and VI contain a detailed, quantitative analysis of financial and market penetration models. They indicate areas of concern that are currently under investigation, and which will be more fully developed in later documents.

A large number of financial factors, ownership arrangements, and tax incentives can alter the cost of solar power to users. Section V describes a methodology that is being developed to analyze these factors and their effects on investment decisions; this methodology is also compared with existing models to evaluate its usefulness. Since this methodology is still being developed, there are several areas where it can be improved or expanded; these areas are noted in the concluding subsection.

Previous studies have often assumed that once solar thermal power attains costs comparable to the alternatives, it will begin to infiltrate the energy market; the levels of such infiltration are estimated by market penetration models. Section VI, however, emphasizes that there are many other factors besides cost comparability that determine market share, and that penetration models can produce inaccurate results depending on the model used and the assumptions made. Existing models are surveyed, and their strengths and weaknesses are discussed; a final subsection contains recommendations and conclusions pertaining to market penetration forecasts.

Having explored the technological, economic, financial, and market demand factors that may affect solar thermal investment, Section VII focuses on another area of concern: regional variations in the solar resource itself. Insolation varies on a seasonal and daily basis; intensity differs by latitude, climate, presence of pollutants, and levels of urbanization. Data on locations best suited to solar thermal power is very sparse, and a better understanding of weather variations and their effects on solar output is needed. The final subsection of Section VII contains a set of proposals for data acquisition and research needed to make an assessment of solar resource availability.

Section VIII summarizes the conclusions presented in the previous sections, attempts to organize the results into a unified framework, and compiles a recommended research agenda for dispersed solar thermal systems.

SECTION II

PRINCIPLES OF SOLAR THERMAL ENERGY PRODUCTION

A. GENERAL THEORY

Solar thermal power systems convert solar flux or insolation to a useful energy form by the intermediate conversion of sunlight to thermal energy. The final energy products are typically electricity or heat, but may include mechanical and other forms of energy depending upon the needs of specific applications.

Unlike a conventional thermoelectric power plant, where power is generated from an internal heat source, solar thermal power systems utilize a remote heat source, the sun. Energy radiated from the sun is attenuated by distance and the atmosphere before it reaches the earth, achieving power density levels of about 1 kW/m^2 on a sunny day. The sun is an intermittent energy source, available only during the day and prone to blockages by clouds. Solar thermal power systems collect, concentrate and capture this sunlight to generate thermal energy. The thermal energy is then transported to another location where it is converted to electricity. In order to overcome the intermittent nature of the sun as an energy source, solar thermal power systems may store the collected energy or use fossil fuel (or other) energy sources for backup when solar energy is not available. These processes describe the four major subsystems of a solar thermal power system: the collector subsystem, the power conversion subsystem, the energy transport subsystem, and the energy storage subsystem.

Figure 2-1 shows the configuration of a general solar thermal power system and its major subsystems. The collector subsystem is usually composed of two components, the concentrator and the receiver. The concentrator redirects and focuses sunlight at the receiver. The receiver absorbs the sunlight and generates heat. The energy transport subsystem delivers thermal energy from the receiver to thermal storage for later use or to the power conversion subsystem for conversion to electricity. Energy storage may consist of two types of storage: thermal storage, which stores and releases heat; and electrical storage, which stores and releases electricity. Hybrid operation refers to the use of fossil fuels (or other energy sources) to backup solar power generation when insolation is not available. The combustion of fuel is used to supply an alternate thermal energy source for the power conversion subsystem.

There are three basic configurations of solar thermal power systems which involve combinations of two types of collectors and two types of power conversion. The two collectors are central receiver systems and distributed receiver systems. Central receivers consist of a field of sun-tracking mirrors (heliostats) concentrating sunlight to a tower-mounted receiver. Distributed receiver systems consist of a field of small collector modules, each with their own receiver, generating thermal energy at a multiplicity of sites within the field. The two types of power conversion are central conversion and distributed conversion. Central conversion systems involve one

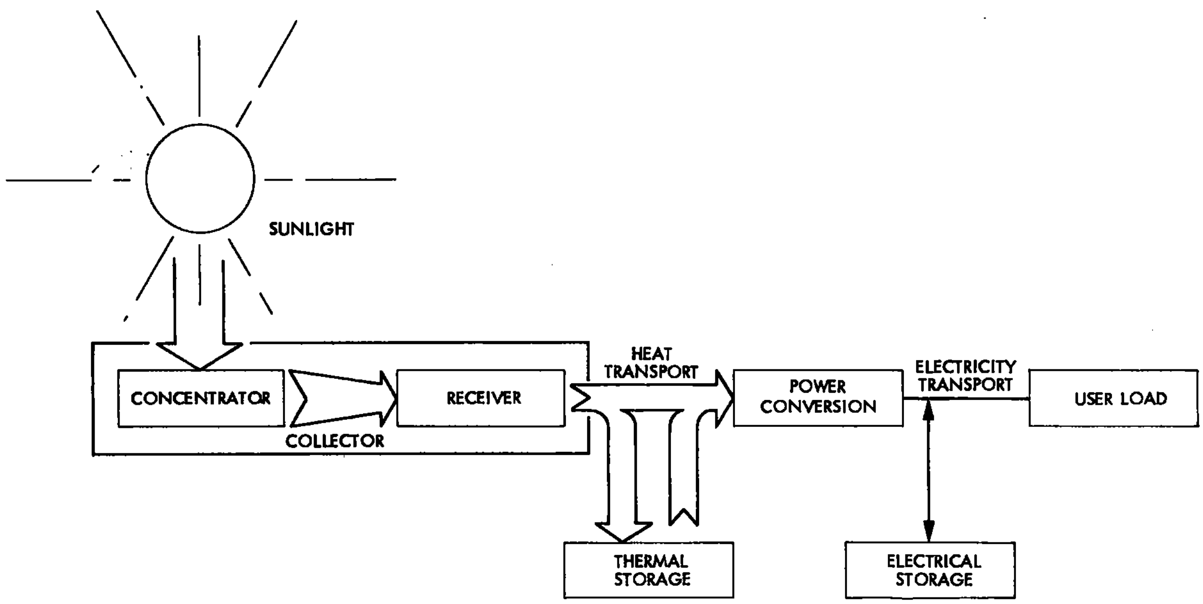


Figure 2-1. A Solar Thermal Power System and Major Subsystems

large power conversion facility within the solar thermal power system. Distributed conversion systems, which are associated only with distributed receivers, consist of many smaller modules. The three basic solar thermal power systems are central receiver with central conversion, distributed receiver with central conversion, and distributed receiver with distributed conversion.

B. SUBSYSTEM THEORY

1. Collectors

As stated previously, the collector subsystem is usually composed of a concentrator and a receiver. The concentrator redirects and focuses sunlight on the receiver using mirrors or lenses. The receiver operates as a special heat exchanger which absorbs the light, converts it to heat, and transfers the heat to the energy transport medium.

Since the collector subsystem of a solar thermal power system may comprise over 50% of the cost of the entire system, the quality and type of collector used has a major impact on the eventual performance of the solar thermal power system. Two important parameters of the collector are the aperture area and the concentration ratio. The aperture ultimately determines the size of the sunlight collecting area and power capacity of the solar thermal power system. The concentration ratio determines the concentrating abilities of the concentrator and the temperature of the heat produced at the receiver. Higher concentration ratios and correspondingly higher temperatures are desirable because increased thermodynamic efficiency is possible in the power conversion subsystem. Basically, there are three types of collectors: fixed, one-axis tracking, and two-axis tracking. Generally, the maximum temperature generated at the receiver and the overall system performance increase as more degrees of freedom are used in the collector. This situation arises because more degrees of freedom allow higher concentration ratios to be realized.

a. Fixed Collectors. Fixed collectors are usually implemented as flat plates mounted on site in a fixed orientation which optimizes annual solar energy collection. Little or no concentrating components are used in these devices. Basic construction consists of copper or aluminum absorber tubes covered with sheets of glass to trap solar energy by using the principles of selective absorptivity and emissivity. The advantages of fixed collectors are simplicity and accompanying low cost. However, because of low concentration ratios, maximum operating temperatures are usually restricted to less than 100° C.

Tubular collectors that utilize evacuated tubes with selectively coated internal absorber tubes to boost temperatures to over 150° C are an improvement over basic collectors. Figures 2-2 and 2-3 illustrate a collector produced by General Electric. Other improvements use non-directional concentrating elements such as reflective backings and compound parabolic (CPC) reflectors as shown in Figures 2-4 and 2-5. Such devices operate at temperatures up to 120° C. Further improvement is possible by combining an evacuated tube absorber with compound parabolic reflector that can operate

FIXED COLLECTOR EXAMPLES

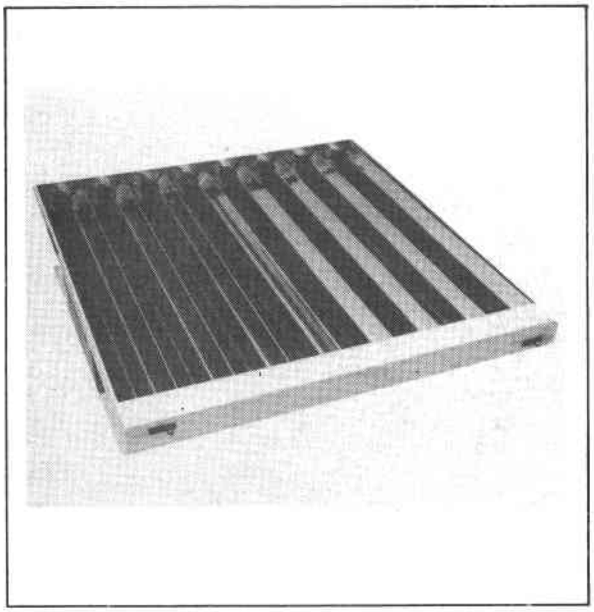


Figure 2-2.
Evacuated Tube Collector
(Source: General Electric)

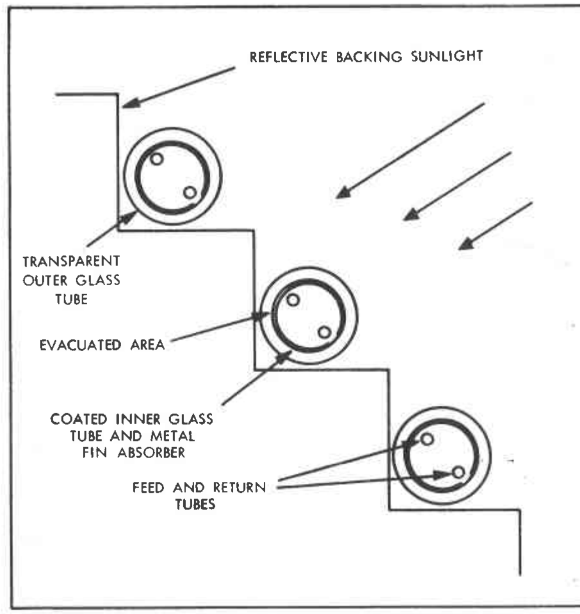


Figure 2-3.
Evacuated Tube Collector
Schematic Diagram

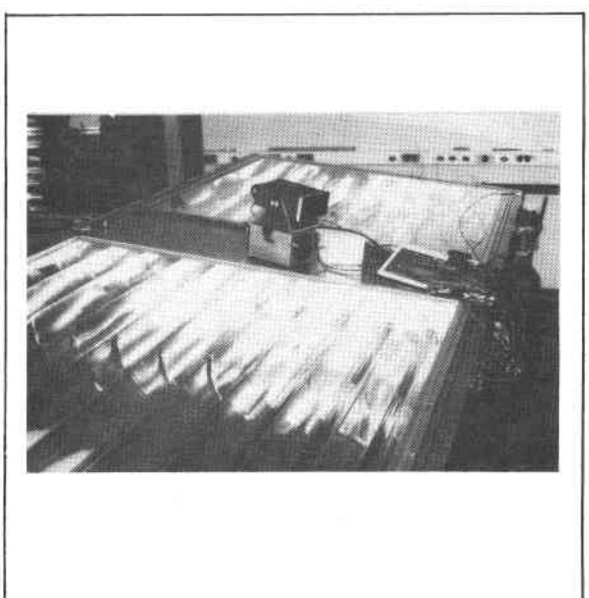


Figure 2-4.
Compound Parabolic Collector

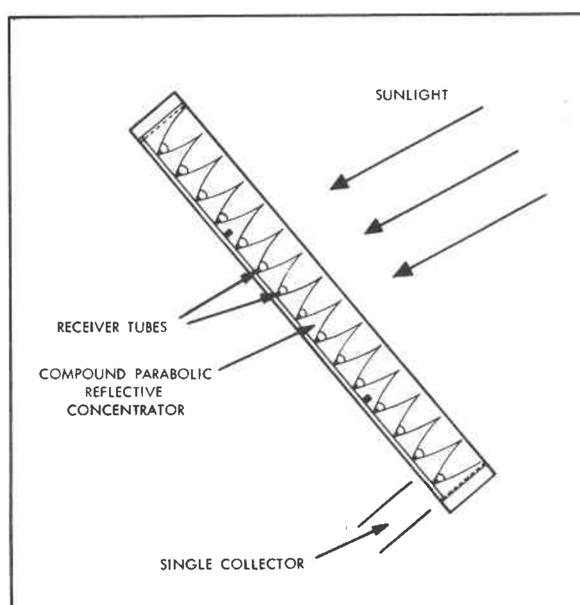


Figure 2-5.
Compound Parabolic Collector
Schematic Diagram

around 200° C. Another strategy to increase performance calls for repositioning the collector several times a year in order to optimize collection performance throughout the year.

Generally, fixed collectors have the advantages of simplicity and relatively lower cost per unit area, plus the ability to use diffuse and nondirect sunlight. The disadvantages of fixed collectors include low temperature generation and low efficiency. Furthermore, fixed collectors suffer from blocking and shading problems due to their fixed nature.

b. One-Axis Collectors. One-axis tracking collector systems achieve higher concentration ratios and higher receiver temperatures than fixed collectors. A typical collector consists of a linear receiver, usually an absorber tube, and a linear concentrating device parallel to the axis of rotation. The axis may either be aligned north-south to track the sun in an east-west direction or aligned east-west to follow the inclination of the sun throughout the day. The north-south alignment can be either horizontal or tilted at the latitude angle for a polar mount.

Several types of one-axis collectors are possible. One design is the parabolic trough collector, consisting of a single curvature parabolic reflector and a linear receiver at the focus. Figures 2-6 and 2-7 illustrate the concept. The size of a unit is restricted to about 2 meters in width and the reflector is a deep trough with great curvature (large rim angles) because the units must be rotated in one piece to follow the sun. A less efficient absorber-type receiver tube which restricts temperatures to less than 320° C must be used because of the reflector shape. A typical system consists of banks of collectors connected in a row using a single sun tracking mechanism to operate an entire row.

A second type of collector uses the linear Fresnel lens (not shown). An extruded, acrylic-plastic, linear Fresnel lens provides the concentrating element of the collector. The receiver element of the collector is a selectively-coated absorber tube at the focus. The whole unit is rotated to follow the sun. Temperatures from 100° C to 260° C are possible.

Another one-axis collector concept is the fixed concentrator, tracking receiver collector. The concentrator is mounted in a fixed position while the receiver is moved to track the focus of the sun, as shown in Figures 2-8 and 2-9. The concentrator usually consists of fixed, stepped mirrors.

A fourth type of collector is the linear heliostat, fixed receiver collector. In the operation of this collector, the receiver is fixed, and light is focused on it by an array of long narrow mirrors (linear heliostats) that follow the sun. Because the concentrator can assume any shape, flat or curved, and individual heliostats can be moved, size is no longer a restriction. Lower effective rim angles are possible, allowing a more efficient linear cavity-type receiver, producing temperatures up to 480° C, to be used. A typical system may consist of many distributed receiver units, as shown in Figures 2-10 and 2-11; or it may consist of one large central receiver with a field of linear heliostats, as shown in Figures 2-12 and 2-13.

Overall, one-axis tracking collectors provide the benefits of higher concentration and output temperatures as well as the advantages of simple tracking mechanisms and support structures which reduce costs. One-axis

ONE AXIS TRACKING COLLECTOR EXAMPLES

Parabolic Trough

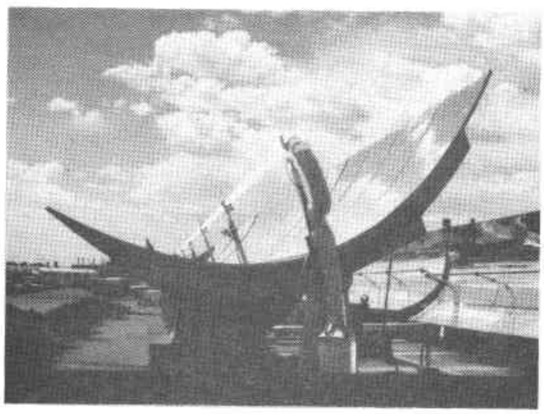


Figure 2-6.
Parabolic Trough Collector
(Source: Hexcell, Sandia-A)

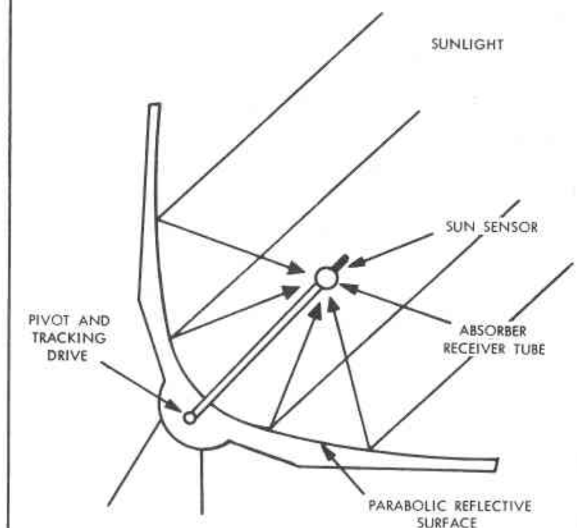


Figure 2-7.
Parabolic Trough Collector
Schematic Diagram

Fixed Concentrator, Tracking Receiver

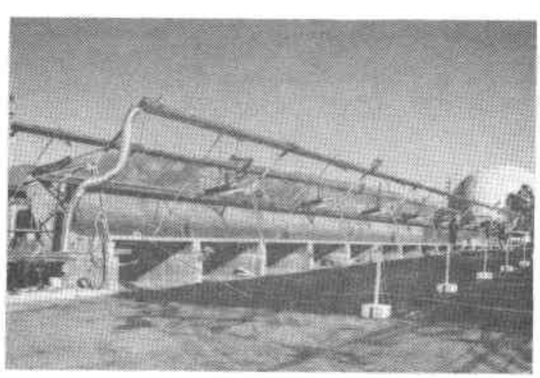


Figure 2-8.
Fixed Concentrator, Tracking
Receiver (Source: GA, Sandia-A)

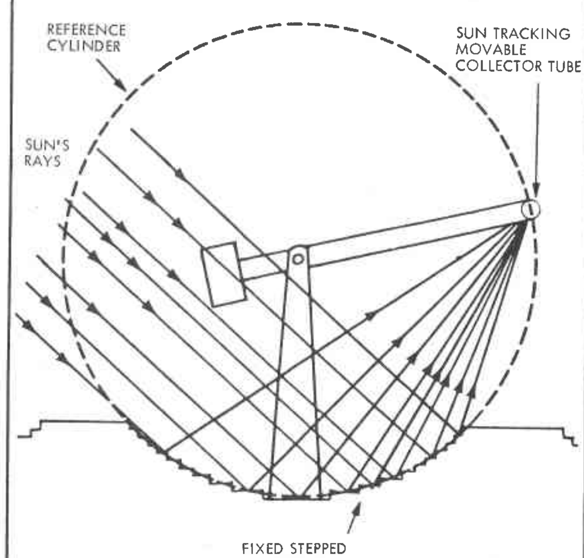


Figure 2-9.
Fixed Concentrator, Tracking
Receiver Schematic Diagram

ONE AXIS TRACKING COLLECTOR EXAMPLES

Linear Heliostat

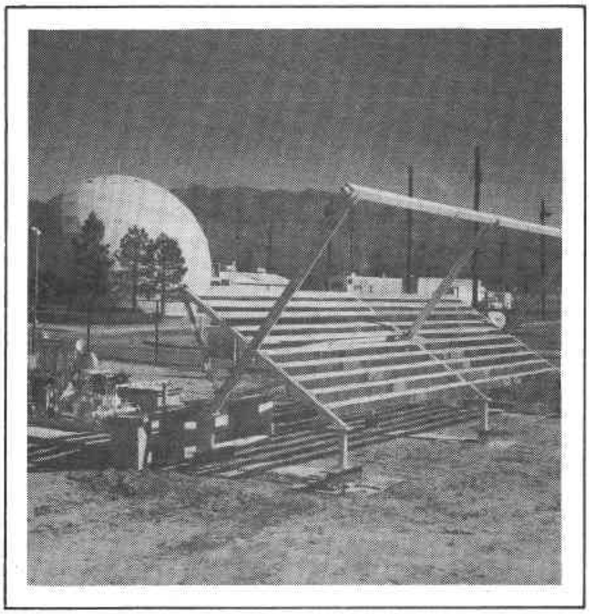


Figure 2-10.
Linear Heliostat, Distributed Receiver (Source: SLATS, Sandia-A)

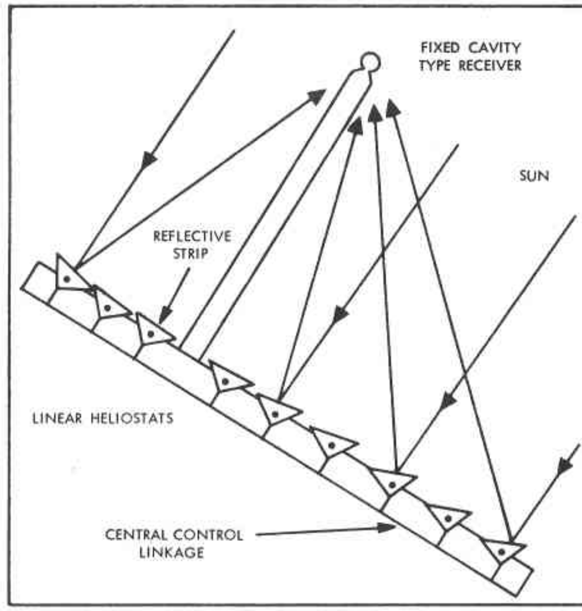


Figure 2-11.
Linear Heliostat, Distributed Receiver Schematic Diagram

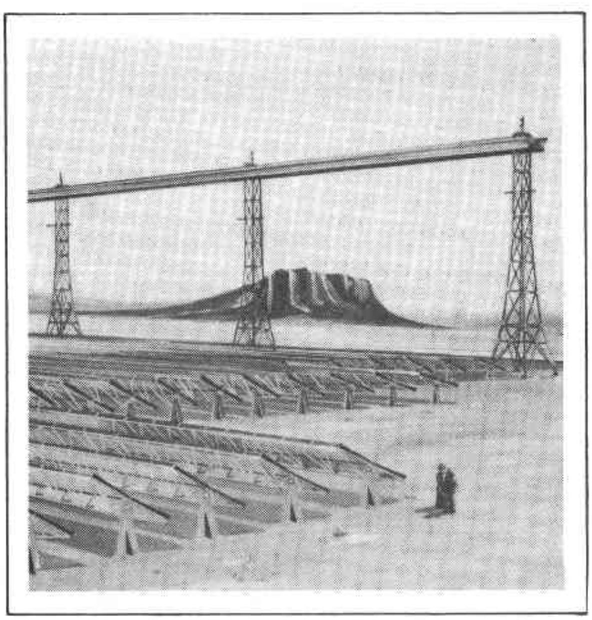


Figure 2-12.
Linear Heliostat, Central Receiver (Source: FMC Corporation)

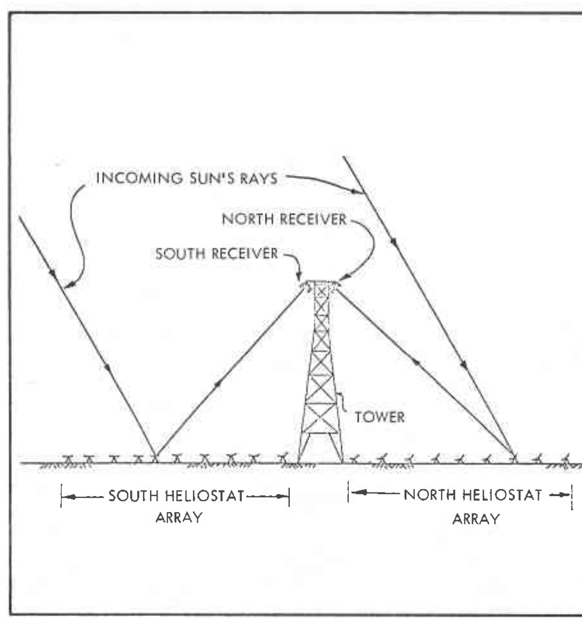


Figure 2-13.
Linear Heliostat, Central Receiver Schematic Diagram

collectors also reduce the blocking and shading problems found with fixed collectors, but they suffer from off-angle (cosine) losses. Further improvements in these areas are possible with two-axis tracking collectors.

c. Two-Axis Collectors. The two-axis tracking collector is associated with compound curvature reflecting surfaces, such as parabolic dishes, which concentrate energy on an aperture that approaches a point. Two-axis tracking collectors minimize blocking and eliminate cosine losses associated with one-axis and fixed collectors which point directly at the sun. This property maximizes the amount of solar energy captured per unit area of collector aperture. Two-axis collectors provide point-focusing capabilities and the potential for higher concentration ratios and higher temperatures. Two basic two-axis collector concepts are central receivers and distributed receivers. Central receivers consist of a field of two-axis tracking mirrors (heliostats) that redirect and focus insolation on a large tower-mounted receiver, as shown in Figures 2-14 and 2-15. Very large systems may be built and temperatures up to 600° C are possible. Advanced systems may achieve 800° C.

Distributed receiver collector systems consist of a field of individual two-axis collector modules. As shown in Figures 2-16 and 2-17, a module typically consists of a compound parabolic reflecting concentrator with a two-axis sun-tracking mechanism. A point focus is achieved and high efficiency cavity-type receivers are used. Temperatures of 800° C are frequently stated. Advanced systems may operate at 1000° C or higher. In addition to parabolic dishes, other possibilities include large Fresnel lenses, staggered multiple-facet concentrators, and large fixed dishes with two-axis tracking receivers.

Proceeding from the fixed orientation to the one-axis tracking and finally to the two-axis tracking system, collector performance improves while the temperature level also rises. Higher temperatures achieve higher thermal-to-mechanical energy conversion efficiencies. This trend of increasing performance with more sophisticated collection systems is accompanied by increasing costs per unit of collector area and the need for additional technology development.

2. Power Conversion

The power conversion subsystem provides for the conversion of thermal energy into a usable form of energy. In most applications, there is a need for electricity or heat at an appropriate temperature. This section will focus on the conversion alternatives for generating electricity.

Solar thermal electric power systems typically utilize a heat engine coupled to a generator to produce electricity. Heat engines accept heat at a high temperature, generate useful work, and reject heat at a lower temperature. The efficiency of a heat engine is bounded by the ideal Carnot cycle efficiency, which depends on the difference between the input temperature and the rejection temperature. In essence, the higher the attainable input temperature, the greater the potential for improved heat engine efficiency. Because the cost of most solar thermal power systems is critically dependent on the cost of the collectors, the required area of the collector will be dependent on the efficiency of the conversion subsystem.

TWO AXIS TRACKING COLLECTOR EXAMPLES

Central Receiver

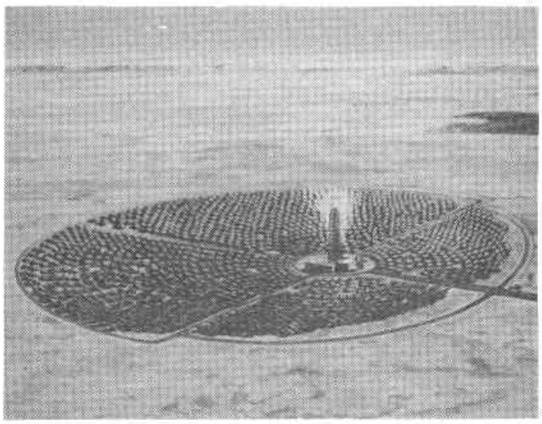


Figure 2-14.
Central Receiver

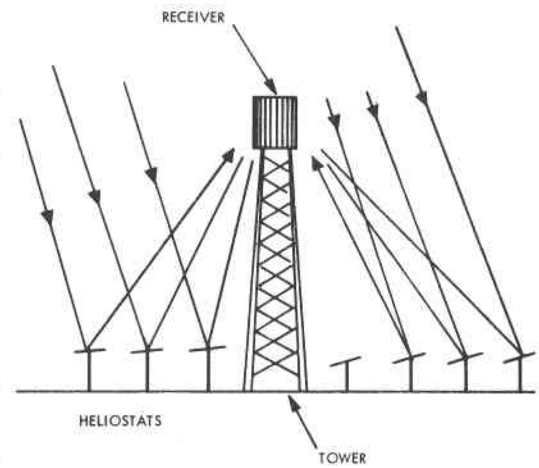


Figure 2-15.
Central Receiver Schematic Diagram

Distributed Receiver

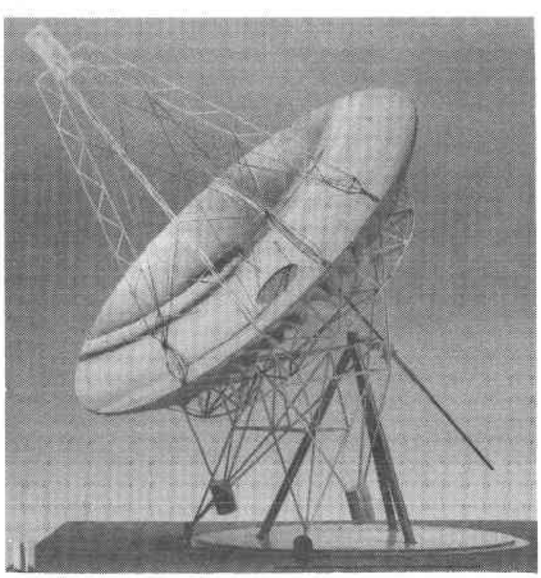


Figure 2-16.
Parabolic Dish

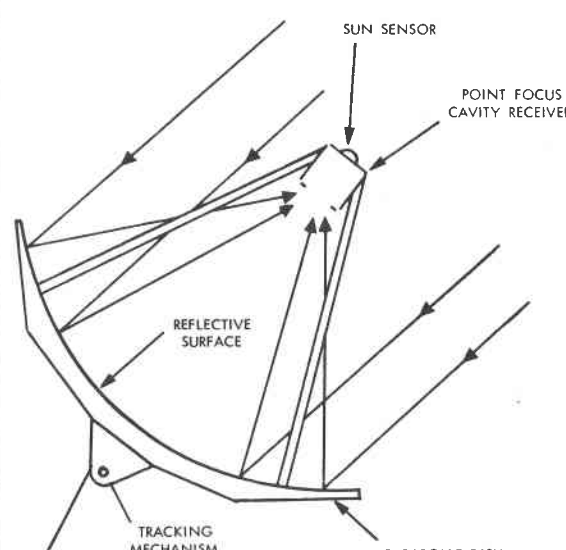


Figure 2-17.
Parabolic Dish Schematic Diagram

Practical conversion cycles operate at much lower efficiencies than the Carnot cycle, but they still exhibit the dependence of efficiency on input temperature. Three conversion cycles which are considered as suitable for solar thermal power systems are the Rankine, Brayton, and Stirling cycles.

a. Rankine Cycle. The Rankine cycle has been used for well over a century in applications ranging from steamboats to nuclear power plants. Water is the usual working fluid. Fluids other than water, such as liquid metals and organic fluids, have been used for Rankine cycles. Comments on such fluids will be given at the end of this section.

The principles of the Rankine cycle are thoroughly understood. A fluid is heated to a saturated or superheated vapor state in a boiler and is expanded through turbine blades, or pistons, to a low pressure. The vapor is then condensed back to a liquid state, and returned under pressure to the boiler, as shown in Figure 2-18. There are several refinements that help to achieve higher efficiencies in more sophisticated systems. Among these are reheat between expander stages and feedwater heating. Current engineering interest in Rankine cycle development is due to automotive and solar power applications.

Modern stationary steam power plants in the 300 MWe to 500 MWe size range achieve power conversion thermal efficiencies (net electric output to heat input) of up to 42%. This is accomplished with multi-stage turbines using steam at 540° C with single reheat and multiple feedwater heating. Current technology is limited to 600° C with one plant designed for 650°C. Considerable advanced technology will be required to achieve temperatures greater than 650°C. Higher temperatures require water of ever higher purity and feedwater treatment to forestall erosion and corrosion effects in expander stages. Commercial turbine/generator sets in the 30 kWe to 50 kWe size range have efficiencies typically less than one-third that of the large modern steam plants. This is due to a combination of economic and technical constraints, such as applications using waste steam at lower temperature and pressure, or simpler system configurations at lower capital cost for smaller systems.

Prior to the widespread introduction of modern turbines, the steam reciprocating engine was the prime mover for electric power generation. In the early 1900's, engines up to 5000 hp were in use with reported power conversion efficiencies up to 21%. Steam conditions typically were 200° C and 250 psig. Rotating speeds generally were low, typically 450 rpm, so that reliability and life characteristics were very good. The efficiency crossover point favoring steam turbines over engines generally is in the 500 kW to 1000 kW range. Little work has been expended on small-size steam turbines; most are single stage and have relatively low efficiency. Thus, in the smaller size, current development favors reciprocating expanders over steam turbines. Impetus for development work on reciprocating expanders was gained from interest in automotive applications.

The material presented thus far in this section pertains to water as the working fluid for Rankine cycles. Liquid metals and organic fluids for Rankine cycles are other possibilities for working fluids. Liquid metals are used generally at much higher temperatures than water, whereas organic fluids are more appropriate for low temperatures. Organic working fluids remain vaporized at conditions of temperature and pressure where steam will

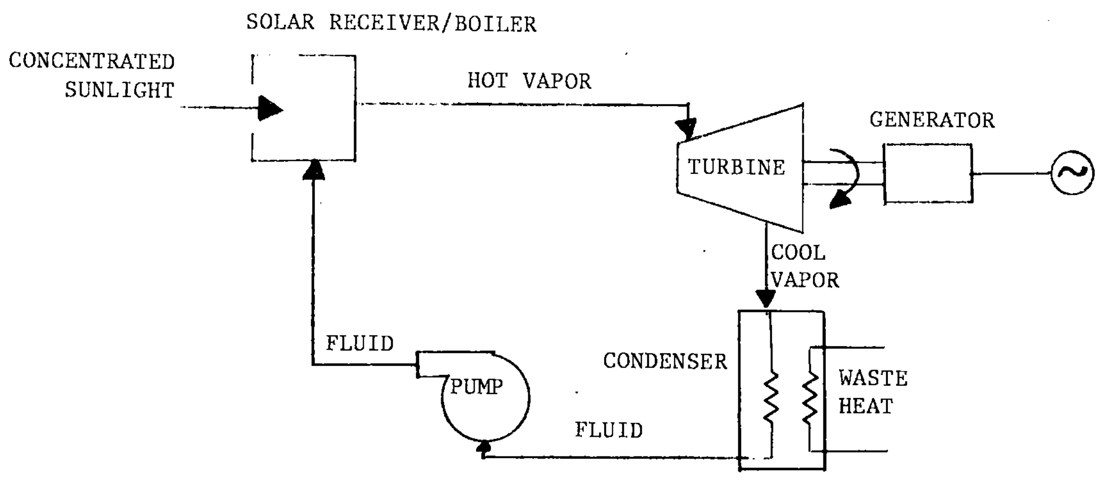


Figure 2-18. Simple Rankine Cycle

condense. (Erosion by droplets can be a significant problem in steam systems using high velocities.) An additional advantage of organic fluids and liquid metals is that high density (compared to water) permits the design of very compact turbines that are much smaller than steam turbines of comparable power output. The efficiency of organic Rankine cycles under current development generally is better than simple, single-stage steam cycles but poorer than multi-stage steam cycles. Most organic Rankine turbines are of single-stage design.

Overall, the Rankine cycle permits a great range of design options and the conversion efficiencies vary widely. Efficiency depends principally on several design features: the maximum temperature and condensing temperature of the cycle; the efficiency of the turbine or piston expansion process and the mechanical efficiency of the system; the working fluid; the size of the engine; and other features, such as the number of expansion stages, use of feedwater heating, etc. Efficiencies of large steam Rankine systems, as stated previously, can exceed 40% for large complex systems. Smaller reciprocating steam Rankine engines operate in the 20% to 30% efficiency range. Organic Rankine cycles operating at low (100° C to 300° C) temperatures yield efficiencies of 15% to 25%.

b. The Brayton Cycle. The Brayton cycle has been exploited successfully for many years in aircraft jet engines which, however, are not notably efficient in terms of shaft horsepower. In principle, the Brayton cycle can be utilized in reciprocating engines but much more attention has been focused on gas turbine development. Gas turbines commonly are used by utilities to generate electric power during peak demands. Such usage is limited because simple gas turbines are relatively inefficient and require clean fuels. They employ high rotational speeds, requiring considerable gear reduction, and require careful manufacture; however, they are low in initial cost and attractive for this utility peaking operation. Relatively little effort has been devoted to developing small engines (of interest for solar thermal power applications) in the size range below several hundred horsepower.

The Brayton cycle uses a gaseous working fluid throughout the cycle. A compressor compresses the gas which is then heated and allowed to expand through a turbine. The turbine itself is relatively inefficient because turbine exhaust gases leave at a fairly high temperature, wasting useful heat. The traditional method to increase Brayton cycle performance is recuperation, which involves a high temperature gas heat exchanger that uses waste exhaust heat from the turbine to preheat the gaseous working fluid leaving the compressor. In large, complex gas turbine systems utilizing multi-stage compressors and turbines, intercooling (between compressor stages) and reheat (between turbine stages) may be used effectively. However, such measures may not be cost effective in small solar thermal systems. An example of a small Brayton engine is shown in Figure 2-19.

The ideal efficiency of the simple Brayton cycle is dependent only on the system pressure ratio. In practice, the cycle efficiency depends on peak cycle temperature, ambient temperature, pressure ratio, and component efficiencies of the turbine and compressor. Materials considerations limit the current peak cycle temperature to a maximum of about 900° C - 1000° C. Higher temperatures require turbine blade cooling by water or gas. Ceramic or cermet turbine blade technology may extend this range considerably. In the

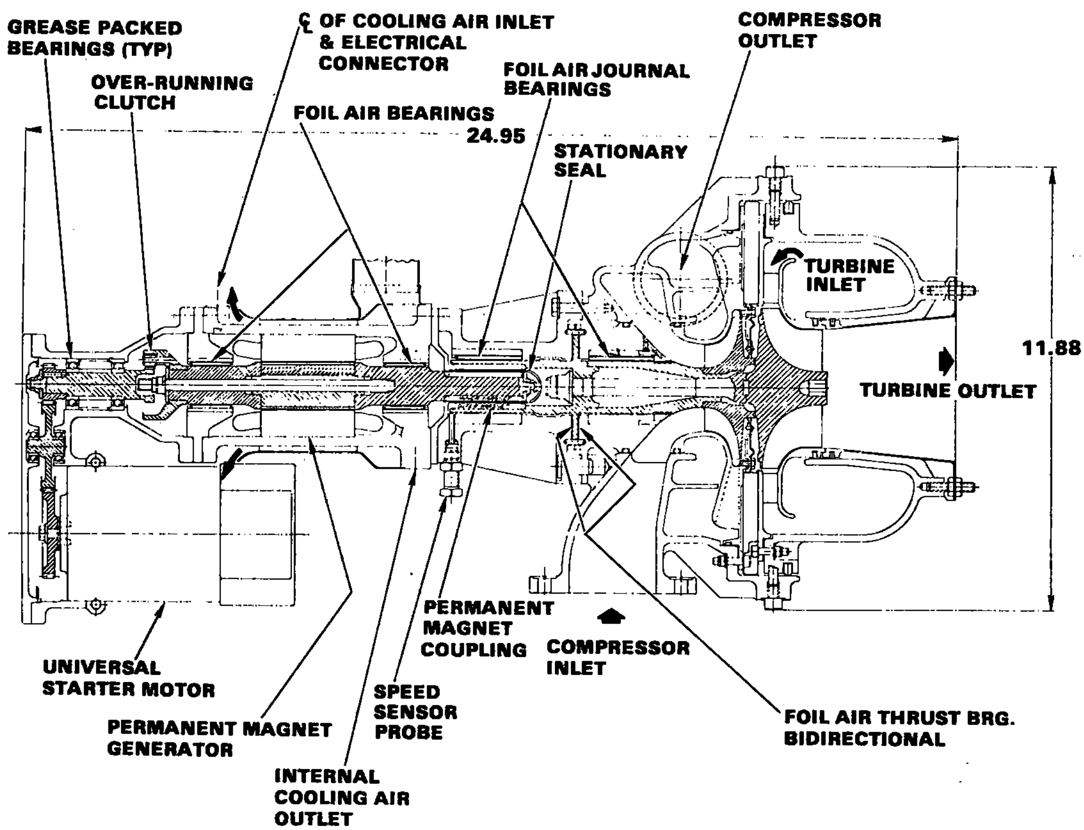


Figure 2-19. Brayton Engine/Alternator Rotating Assembly
(Source: Garrett AiResearch)

far term, cycle temperatures of the order of 1500° C may become possible. Recuperators, too, are temperature-limited by materials. Thermal cycling of high-temperature commercial recuperators poses a challenging problem from the standpoint of durability and replacement cost.

Three different types of Brayton cycles are applicable to solar thermal applications: open cycles, closed cycles and inverted cycles (or subatmospheric cycles). An open cycle system, shown in Figure 2-20, draws in air, at atmospheric pressure, through a compressor coupled to the turbine. The compressed air is preheated by the recupertor from the hot exhaust air. The preheated compressed air is then superheated by the solar receiver and allowed to expand through the turbine to produce work. The rotating turbine powers the generator and compressor. Hot turbine exhaust is passed through the recuperator to preheat incoming air, then exhausted to the atmosphere.

Small open cycle engines, approximately 20 kWe in size, currently achieve 25% to 30% efficiency and may be expected to reach 35% to 40% efficiency after much further R&D effort. Larger engines offer better mechanical component efficiencies as well as more sophisticated multi-stage, intercooling, and open cycle reheating techniques, resulting in higher efficiencies. Large open-cycle engines, approximately 10 MWe in size, may reach efficiencies of 40% to 45% after more R&D effort.

Closed cycle systems remove waste heat through an additional heat exchanger which creates a closed system, as shown in Figure 2-21. Closed cycles exhibit only slightly higher efficiencies than open cycles, approximately two or three percentage points. However, a variety of working fluids such as argon, krypton and xenon may be used, which offer better heat transfer characteristics than air, resulting in generally smaller and more compact machinery than open cycle engines of equivalent rating. Closed cycle systems do not require gas filtering, so that they have an advantage in dust/dirt laden environments, such as deserts. All considered, the trade-offs in performance and cost between open and closed cycles are not well-defined, and differences in part-load efficiencies and control may be decisive factors in a comparison.

The inverted cycle utilizes the compressor as a vacuum pump. As shown in Figure 2-22, air is drawn directly into the recuperator, heated in the solar receiver, then expanded through the turbine into a vacuum created by the compressor. One advantage of this cycle is that the solar receiver may operate at atmospheric pressure without metal or ceramic containment being required. This could effect considerable cost savings and enhance reliability. The efficiency of inverted cycles is similar to closed cycles, but the engine size is larger due to the lower pressure of the working fluid.

c. The Stirling Cycle. The Stirling cycle and the closely related Ericsson cycle have been known for a long time. The Stirling cycle was first used commercially more than 100 years ago; however, the rapid development and application of internal combustion engines and other cycles left the Stirling cycle in the backwater of research and development until recently.

The Stirling and Ericsson cycles are attractive because of their potentially high performance since they alone, of all current heat engine cycles, offer the potential of achieving Carnot efficiency. This is true

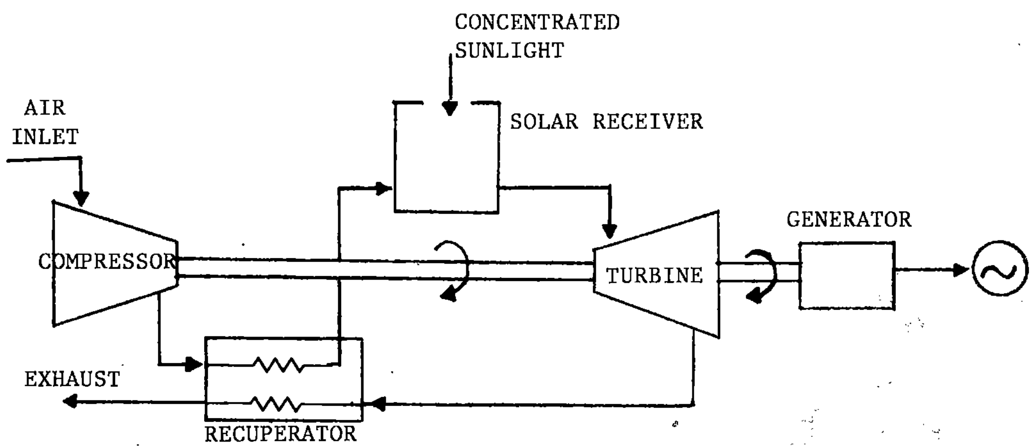


Figure 2-20. Open Brayton Cycle

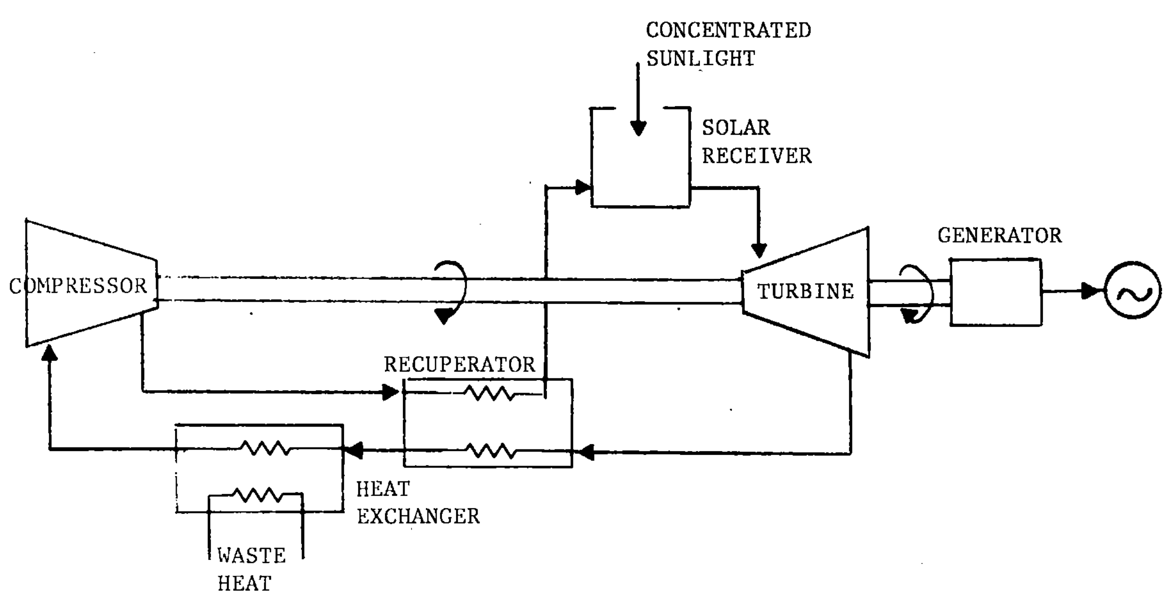


Figure 2-21. Closed Brayton Cycle

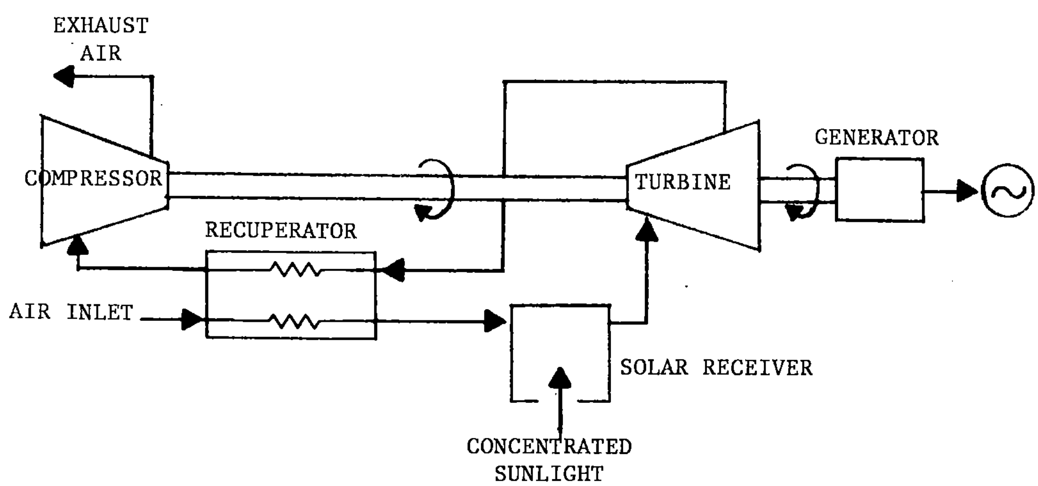


Figure 2-22. Inverted Brayton Cycle

because, in principle, the compression and expansion processes of the engine are isothermal; however, in real engines, perfect isothermal processes cannot be achieved. Besides high performance, other advantages of Stirling engines often stated are long lifetime, quiet and reliable operation, and low pollution levels when driven by fossil fuels. Stirling engines operate at low rpm and therefore do not require costly, high-reduction gear trains.

Stirling cycle devices are piston engines that cycle a closed volume of gas between a hot heat source and a cold heat sink. Figure 2-23 illustrates the operation of a Stirling cycle. The key to the performace of the Stirling cycle is the regenerator between the hot and cold volumes. Following Figure 2-23, (1) cold gas is passed through the regenerator to absorb heat from the previous cycle, (2) the now heated gas is allowed to absorb heat from the hot source and expand against a piston to perform work, (3) the hot gas is then returned through the regenerator to store heat in the regenerator for the next cycle, and (4) the gas which is now cooler, is compressed and made to release waste heat to the cold heat sink, thus completing the cycle. The difference between the Stirling and Ericsson cycles is that the Stirling cycle passes gas through the regenerator at constant volume while the Ericsson cycle accomplishes this at constant pressure.

There are two types of Stirling engines under development: the mechanical-drive Stirling engine which involves a rotating crankshaft power drive; and the free-piston Stirling engine, which drives a non-mechanically linked linear oscillating piston as shown in Figure 2-24. Mechanical-drive Stirling engines already have achieved thermal efficiency in excess of 40%. Advanced engines using as-yet-undeveloped technology are expected to achieve efficiencies in the 50% to 60% range. Free-piston Stirling engine development lags behind the mechanical-drive type by several years. Free-piston Stirling engines have achieved about 30% thermal efficiency, and 40% or more is expected in the near-term as a result of further research. Free-piston engines offer the option of direct generation of electricity using linear alternators, thus eliminating potential mechanical losses.

Stirling engines are closed-cycle machines; the current choice of working fluids is helium or hydrogen. Heat is applied externally using another heated fluid such as air or liquid metal. Thus, the engines are readily adaptable to a wide variety of heat sources, including solar, and many different fuels. Internal heat transfer and fluid dynamics in Stirling engines and in the regenerators and heaters are extremely complex. The achievement of higher heater temperatures (exceeding 800° C), and thus higher performance, is beset by several problems associated with advanced materials development.

Technology risk areas that require further development include the heater head (cost and durability) and seals for the pistons and piston rods to prevent working fluid contamination. In solar applications, additional work is needed to develop heat transport systems to the heater head and stable control systems. It is anticipated that Stirling engine mass-production trends will be similar to that of automotive engines, but mass-production techniques require further study. Costs are projected to parallel Diesel engines. The lifetime of Stirling engines is an open question. It is encouraging that laboratory engines have run in excess of 25,000 hours.

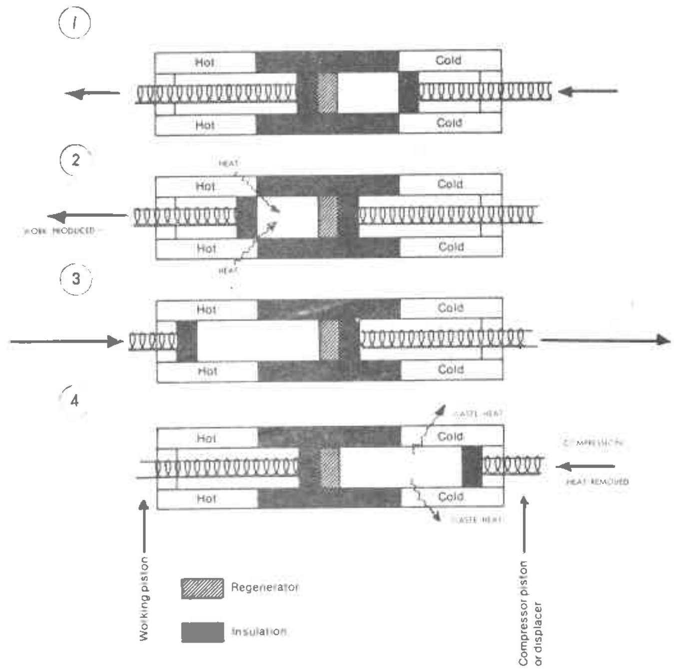


Figure 2-23. Stirling and Ericsson Cycles

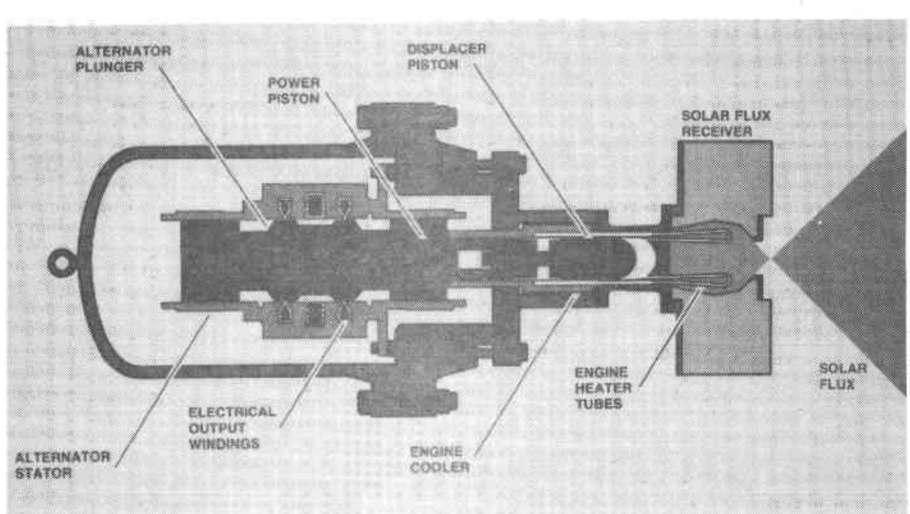


Figure 2-24. Free Piston Stirling Engine/ Alternator System

Stirling engines are being developed by several companies in the United States and abroad, but none are yet available commercially. Many small engines in the range of a few kW to 20 kW have been built and tested for research purposes. Several European companies are developing engines in the automotive size range. The Department of Energy currently is evaluating the use of larger Stirling engines for stationary production of power.

3. Energy Transport

The energy transport subsystem has the responsibility of delivering energy collected at the collector to the other solar thermal subsystems, power conversion and storage, as well as to the application or user. The type of energy transport subsystem used depends on the type of collector used, the type of power conversion subsystem and the configuration of the solar thermal power system. Ignoring the storage subsystem, there are basically three types of transport within a solar thermal power system: optical transport, connecting the concentrator and receiver; thermal transport, connecting the collector and power conversion subsystem; and electrical transport, connecting the power conversion subsystem to the application. Energy losses in any of these transport systems are determined somewhat by the configuration of the solar thermal power system.

Central receiver systems employ large optical transport systems collecting sunlight from the heliostats at about a 4% energy loss. Other configurations do not have this energy loss problem because of the much shorter optical paths of distributed receivers.

Thermal transport plays a major role in all configurations, especially in distributed receiver, central conversion systems which must collect thermal energy from the many collectors and deliver it over a relatively long distance to the central conversion facility. Pipelines are used to transport the medium used to carry the thermal energy. Rankine conversion systems may use steam pipelines, which over long distances require heavy insulation to keep heat losses down. Brayton conversion systems, which use hot gases, require large diameter pipes to maintain required flow; this makes long pipe runs particularly unattractive for Brayton systems. Stirling conversion systems only require a hot source; in this case, hot fluids may be used as transport mediums. Fluid transport may also be used for Brayton and Rankine systems but additional heat exchange equipment would be required at the power conversion subsystem. Other options include use of reversible thermochemical reactions to generate reaction products at the receiver, which may be cooled and transported at low temperatures to the conversion area where they are recombined to produce heat. Heat loss is reduced because of the low temperature employed.

Electrical transport connects the power conversion system to the application. Outside the power system and site a utility grid may be used, which is highly efficient. Within the site, only distributed receiver, distributed conversion systems require extensive electrical collection and transport. Underground cables are usually considered along with centralized power conditioning equipment for connection to the application.

4. Energy Storage

Insolation varies from hour to hour, day to day, week to week, and season to season. Hence, a major constraint on the evolution of solar thermal power systems is the need to provide continuous operation during periods of solar outage. Continuous power generation may be provided by either hybrid operation or storage. In a solar plant provided with thermal generating storage, during sunshine hours, heat will be transported from the receiver to the energy conversion and storage systems. During post-sunshine hours, stored heat will again be transported from storage to the energy conversion systems. A plant provided with electrical generating storage will essentially shut down its energy conversion system during post-sunshine hours and will supply electrical energy from its storage.

The capability of any particular storage technology with solar thermal power systems is dependent on the type of power conversion and energy transport medium. The important factors in energy storage subsystems are the cost per unit storage, the efficiency, and the temperature requirements of the thermal storage.

a. Thermal Storage. There are three basic approaches to storing thermal energy:

(1) Sensible heat. Storing heat within the mass of a liquid or solid which does not change its state during heating.

(2) Latent heat. Storing thermal energy by heating a solid or liquid which undergoes a phase change to liquid or gas respectively.

(3) Thermochemical. Storing thermal energy by using a reversible thermochemical reaction which undergoes endothermic reaction to store energy and yield reaction products which may be stored and used later in exothermic reaction to produce heat.

Sensible heat storage systems are presently under development, and are scheduled to be used in near term solar thermal power systems. Many storage schemes are possible. The most simple involves directly storing the hot energy transport medium in large tanks for use later. Two-tank storage schemes utilize an insulated hot tank and a separate cold tank for storage of the heat transport medium. Water, oil, or liquid metal systems are examples of two-tank schemes. A dual media storage system involves the transfer of heat to another storage medium which either has a higher specific heat, allowing a smaller storage container to be used, or a lower cost per unit volume, reducing storage costs. Such concepts include Hitec/rock storage, Caloria/rock storage, and magnesium oxide brick storage.

Latent heat storage systems offer higher energy density storage and may potentially be less costly. Furthermore, latent heat systems may also provide a more uniform heat source when discharging storage. Phase change materials (PCM) are used in latent heat storage systems. The candidate PCM in addition to having the proper transition temperature and high latent heat must also have satisfactory chemical and physical properties. It must also be stable, containable, cheap, and preferably non-poisonous. Several PCM salts are potential candidates which include flourides, chlorides, nitrates, bromides, and others. Mixtures of various salts provide wide variations in cost, melting temperature and latent heats.

The storage of thermal energy as the heat of reaction of a reversible chemical system has long been considered an attractive possibility. In these systems, a reversible chemical reaction consumes thermal energy (endothermic reaction) by transforming chemicals into a storable, higher potential energy state during periods of excess energy supply, such as during hours of sunlight. During periods of little or no insolation, the chemical energy storage releases stored heat by the recombination heat of reaction (exothermic reaction) of stored chemicals.

Reversible chemical reaction (RCR) storage systems can be categorized according to the temperature regime in which they operate, by the physical state of the reactants (gas, liquid, or solid), and by the volume change associated with the reaction. The reactions are easier to conduct if all reactants are gases at reaction temperature. The products are easier to store if they are liquids at ambient temperature. A compromise has to be sought between these contradictory requirements. The selection criteria for candidate thermochemical reactions include: energy storage capacity per unit mass or per unit volume, the reaction rates, availability of proper separation techniques of the reaction products, cost of chemicals, toxicity, corrosiveness, and inflammability of the involved chemicals. Some examples of potential condidates are the methanation reaction, the sulfur trioxide reaction, and ammonium hydrogen sulfate reaction.

b. Electrical Storage. Electrical storage systems refer to storage mechanisms which accept electrical energy and regenerate electrical energy. Such devices need not be associated directly with a solar thermal power plant, but may be connected to almost any point on an utility electrical grid. For these reasons electrical storage may also be called external storage. Three types of storage mechanisms are currently possibilities:

(1) Superconductors. Energy is stored in the magnetic field of a superconducting electromagnet.

(2) Mechanical. Energy is stored in the form of the kinetic or potential energy of some mass.

(3) Battery. Energy is stored in a reversible electrochemical reaction.

Energy may be stored in the magnetic field of a superconducting electromagnet. Currently, superconductors must be maintained at very low temperatures. Further problems exist in attaining high magnetic field without degrading the superconductivity of the magnets. For these reasons superconducting devices are unlikely to play a significant role in energy storage.

Mechanical storage systems involve the storage of energy by conversion of electricity to a mechanical motion which stores energy and is reversible. Several such devices are feasible storage mechanisms. Pumped hydro storage involves pumping water from a lower reservoir to a higher one, storing energy in the gravitational potential of the water. Electricity is regenerated by familiar hydroelectric techniques. Other mechanical storage devices include flywheels and compressed air systems.

Battery energy storage is a well known form of chemical energy storage in which direct current (dc) electricity is electrochemically converted to chemical energy during charging, and during discharge chemical energy is converted electrochemically into dc electricity. The advantages of battery energy storage are an absence of moving parts, rapid system response, compactness, and modularity.

Lead-acid batteries are the only devices currently mass produced for storing large amounts of electrical energy using electrochemical reactions. Systems as large as 5,000 kWh are currently used in diesel submarines. Batteries now on the market, which can be deeply discharged often enough to be attractive for onsite or utility storage applications, however, are too expensive for economic use by electric utilities. Extensive work is being done to determine whether it is possible to develop batteries suitable for use in utility systems. Work is being done on advanced lead-acid battery designs and on several types of advanced batteries which it is hoped will be less expensive than lead-acid batteries in the long-term.

There are three basic categories of advanced battery systems under examination:

(1) Aqueous or water-based systems which operate with electrodes surrounded by a liquid electrolyte, as do lead-acid systems.

(2) Nonaqueous high-temperature systems, which use a nonaqueous material to conduct ions needed to complete the electrochemical reaction.

(3) Redox (reduction/oxidation) devices which reduce aqueous solutions to store energy. (redox batteries are aqueous, but they are usually considered separately.)

The redox battery presents an attractive opportunity for electric storage since devices based on the design may be able to store energy in tanks of inexpensive chemicals; storage costs could be $10/kWh or less. The problem which has plagued the development of these systems for many years is the need for a semipermeable membrane with some rather remarkable properties.

In a standard redox battery the two storage tanks (called the catholyte reservoir and the anolyte reservoir) contain different chemicals. In one design, the tank connected to the positive terminal contains a solution of Fe^{+2} and Fe^{+3} ions, and the tank connected to the negative terminal contains a solution of Ti^{+3} and Ti^{+4} ions. When the battery is completely discharged, the one tank is filled with $FeCl_2$ and the other with $TiCl_4$. While the battery is being charged, negatively charged chlorine ions drift across the semipermeable membrane and combine with $FeCl_2$, producing $FeCl_3$ and giving up the extra negative charge to the positive terminal. On the other side of the membrane, chlorine ions are released when $TiCl_4$ forms $TiCl_3$, taking an electron from the negative electrode. The electric current from the positive to the negative electrode is matched by the flow of chlorine ions across the membrane. It is important that the membrane be able to pass chlorine ions with minimal resistance, but not allow either the iron or the titanium to pass. If iron or titanium leaks through the membrane, the performance of the device is gradually degraded. NASA-Lewis has been working on systems based on this design for a number of years, and it is hoped that a battery suitable for demonstration in utility applications will be available by 1985.

5. Hybrid Operation

A hybrid solar thermal power system offers a functional alternative to solar systems using storage subsystems. A hybrid plant implies a system which shares the power conversion subsystem between a solar heat source (receiver) and a fossil-fueled heat source (combustor). The fossil-firing capability provides an energy source back-up when solar insolation is weak or not available. A storage subsystem will also provide backup, but most present storage technologies are only in the initial development phase. Fossil fuel technology is well developed and reduces the risk and uncertainty associated in using storage technologies for backup in near-term solar systems. Hybrid operation offers clear advantages over present day storage subsystems in both cost and performance. This gap is expected to narrow as storage subsystem costs and performance improve and fossil fuels become more expensive.

There are two basic hybrid system configurations: series or parallel. A series system, shown in Figure 2-25a, uses the solar receiver to act as a preheater and the fossil-fueled combustor to bring the working fluid up to operating temperature. The positions of the solar receiver and combustor may be interchanged depending upon the system. A parallel configuration, shown in Figure 2-25b, divides the working fluid flow between the solar receiver and the combustor. Both receiver and combustor bring their working fluid streams up to operating temperature. The flow rate between combustor and receiver is variable depending upon solar insolation levels. Each method offers its own advantages and disadvantages.

C. MAJOR ECONOMIC/PERFORMANCE TRADE-OFFS

In the previous section, the subsystems of solar thermal power system were discussed and a variety of equipment was presented. An important issue in the development of solar thermal power systems is the selection of the best configuration of this equipment. The major criteria in the evaluation of a particular system configuration is the cost of delivered energy, expressed in mills per kWhr (1 mill = 0.1 cent). The capital cost of the installed system, often expressed in dollars per kilowatt ($/kWe) is also important. There are several trade-offs which may be made in the development of a solar thermal power system.

1. Collector Cost-System Efficiency

Preliminary studies have indicated that collectors may account for over 50% of the installed cost of a solar thermal power system. Therefore, the collector area and the cost of a particular collector can be important factors in determining the overall capital cost of a solar system.

Collector cost per unit area increases as more degrees of freedom are used in tracking and correspondingly higher concentration ratios and temperatures are achieved. This relationship is a result of increasing complexity of tracking mechanisms, required manufacturing process, and alignment requirements. The use of more expensive high-concentration collectors may be offset by the corresponding increase in system efficiency as a result of increased collector performance and the consequent increased thermodynamic conversion efficiency from the higher temperatures. Increased system

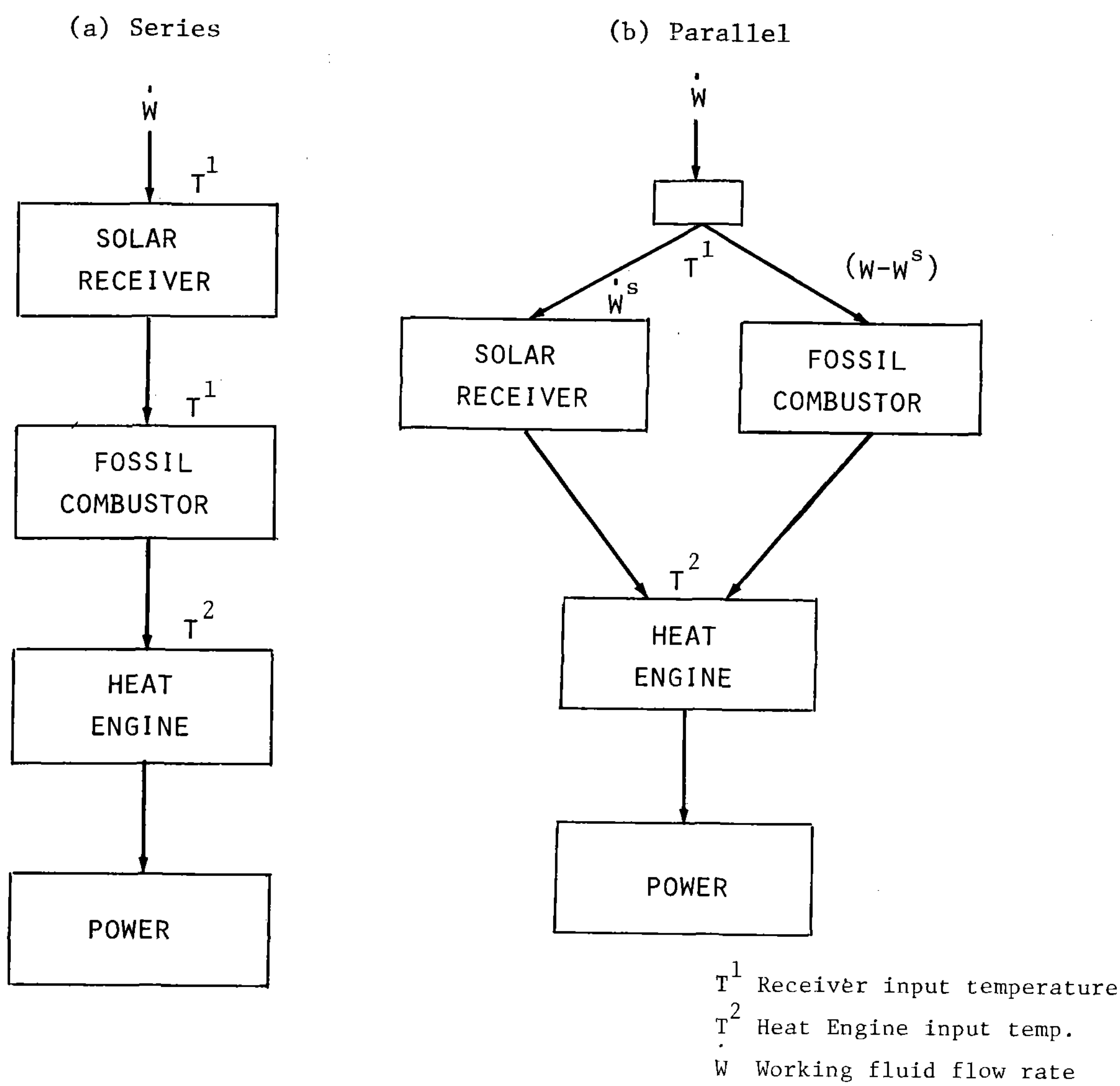


Figure 2-25. Hybrid Configurations

efficiency directly reduces the required collector area, as less solar insolation is needed to produce the same amount of useful energy, lowering overall system capital costs.

As can be seen, the above process becomes a trade-off between system efficiency and collector cost. The optimal choice of collector configuration is a function of its cost estimate and the attainable system efficiency. Current research indicates that high-concentration, higher-cost, two-axis collectors with high-efficiency heat engines are justified by present estimates of collector costs and potential conversion efficiencies.

2. Size Effects

A system or subsystem exhibiting economies of scale costs less per unit performance as the size of the system is increased. This effect is particularly important in solar thermal power systems, where different system configurations exhibit various economies of scale. The ultimate size of the power system now plays an important role in the selection of a configuration. The hypothetical situation in Figure 2-26 illustrates this effect. Power systems less than 10 MWe in size may favor a System 3 technology because it provides the lowest energy cost. Systems between 10 MWe and 100 MWe would favor System 2 technology. Greater than 100 MWe, System 1 technology is preferred.

Central receiver systems or those systems that require thermal transport to a central location for power conversion tend to exhibit greater economies of scale, as typified by a System 1 curve. This effect is primarily due to collector and power conversion economies of scale as well as increasing engine efficiencies with size. Modular type systems that use distributed power conversion exhibit curves similar to System 3. Modular systems consist of a set of complete power generating modules; a two-axis parabolic dish collector with a small heat engine nearby is an example. Since only the addition or removal of small modules are needed to change plant size, energy cost is relatively flat with respect to plant size. Subsystems also exhibit economies-of-scale effects that influence the selection of subsystems. For example, low-temperature thermal storage systems store energy much less expensively in large systems than in small storage tanks. This is because the ratio of surface area to volume increases with tank size, reducing overall heat loss. High temperature storage devices in many cases do not show economies of scale, because storage must often be located near the collector and power conversion systems to reduce heat loss on long runs of transport piping. Collectors, which usually consist of arrays of individual devices such as heliostats and dishes, exhibit optimal size effects. Initially, cost per collector area decreases with size, but increasing structural requirements drive the cost up again after a certain point.

A further complication in selecting power systems based on size, involves the anticipated system cost reduction because of the effect of mass production techniques. For example, consider a hypothetical market for solar thermal power systems of 1000 MWe per year. Initially one might take advantage of the economies of scale of a System 1 type power system and build ten, 100 MWe systems per year to meet the market requirement. Alternatively, one could build one hundred, 10 MWe power systems per year using System 3 technology and take advantage of mass-production techniques in order to, hopefully, reduce

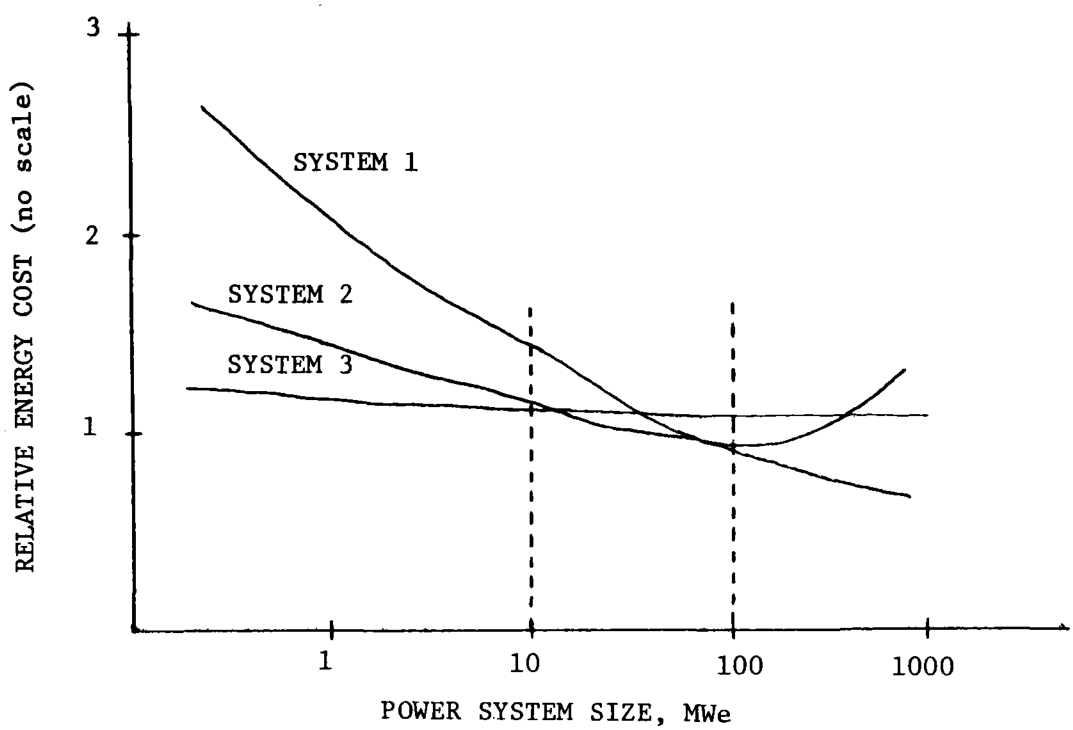


Figure 2-26. Effect of System Size on Energy Cost

svstem costs and provide a lower total energy cost for the entire market. Currently, the effects of mass production on solar thermal power system cost reduction are still uncertain.

3. System Capacity Factor

The load factor of a system is calculated as the ratio of the energy generated by a system and applied to a load, to the energy that a system could produce if it operated at capacity continuously. For example, a 10 MWe system that generated an average 4 MWe over a year would have a load factor of 0.4. In the case of utilities, power systems operated at high load factors are called baseline units and they satisfy the part of the electricity demand that is generally always present. Low-load-factor systems are called peaking units, which are used to supply electricity only when electrical demand exceeds baseline capacity during a peak demand period. An example of a demand which contributes to peaking loads is the high electricity demand for air conditioning during the summer.

With respect to solar thermal power systems, the term capacity factor is often used to rate a system. The capacity factor is similar to the load factor except that it is the ratio of all the energy that a system can generate during a year to the energy that it could generate if it was possible to operate continuously (at rated capacity). Without storage or hybrid operation backup, most solar systems cannot exceed a 0.3 capacity factor simply because the sun may shine only 8 hours a day on average. To increase the capacity factor of the power system, storage or backup is needed to produce energy when insolation is absent, as shown in Figure 2-27.

Ultimately, the configuration of a solar thermal power system will depend more on application requirements of load factor and reliability. Reliability is the probability of receiving power when it is needed. Peak demands during the night or frequent cloud blockages during peak demands will reduce the reliability of solar thermal power systems. If a solar system is used to supply power to a low-load-factor application with demands corresponding to the daily insolation levels, then little storage or hybrid capabilities may be required to meet the load demand. Applications with higher load factors (greater than 0.3) will need solar systems with storage or hybrid capability and higher capacity factors.

4. Capital Cost and Distributed Costs

The overall cost of energy generated by a power system may be thought of as coming from two sources: capital costs and distributed costs. Capital cost, as stated previously, is the installed cost of the system; money that is spent at the beginning of the life of the power system. Distributed costs reflect the money spent on the system during its entire lifetime. Examples of distributed costs are maintenance, insurance, operation and fuel costs. Together, both types of costs determine the cost of energy from the power system.

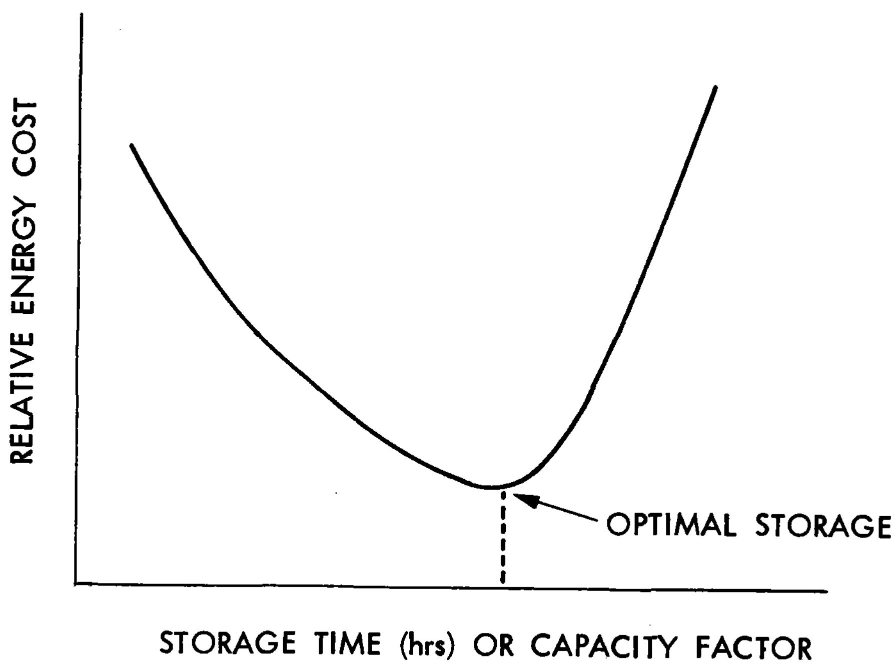


Figure 2-27. Effect of Storage Capacity on Energy Cost

As discussed more fully in Section V, the utility-owned Solar Electric System (USES) Model is one method of determining the cost of energy from a conceptual power system. It discounts the distributed costs, using the cost of capital of the system owner, to the present, and adds in the capital cost to calculate the total present cost of the system. The total present cost is then redistributed in equal annual amounts over the life of the system using a capital recovery factor based on the owner's cost of capital, to determine the annualized cost of the system. The estimated annual energy production of the system is then divided by the annualized cost to get the busbar energy cost (BBEC) of the system. The model then reflects the contribution of both capital and distributed costs on the overall energy cost of the system. A more advanced model (STEAM) is discussed in Section V.

Many trade-offs are present between the capital costs and distributed costs of a solar thermal power system. One of the trade-offs is between the cost of quality and reliability and the cost of maintenance and replacement parts. It may be that a higher cost, long-lived engine may contribute to a higher energy cost than a cheaper, short-lived engine replaced several times during the life of the power system. The capital cost of automatic or self-cleaning concentrators may not be justified against the long-term cleaning costs of other approaches.

These trade-offs are dependent on the power system owner's cost of capital. An owner with a high cost of capital would be willing to accept higher distributed costs in lieu of low capital costs. Owners with low costs of capital will favor higher capital costs in lieu of lower distributed costs. In this respect, the type of owner has much bearing on the particular solar thermal power system configuration.

SECTION III

GENERAL SYSTEM CONCEPTS

A. OVERVIEW OF SYSTEM CONCEPTS

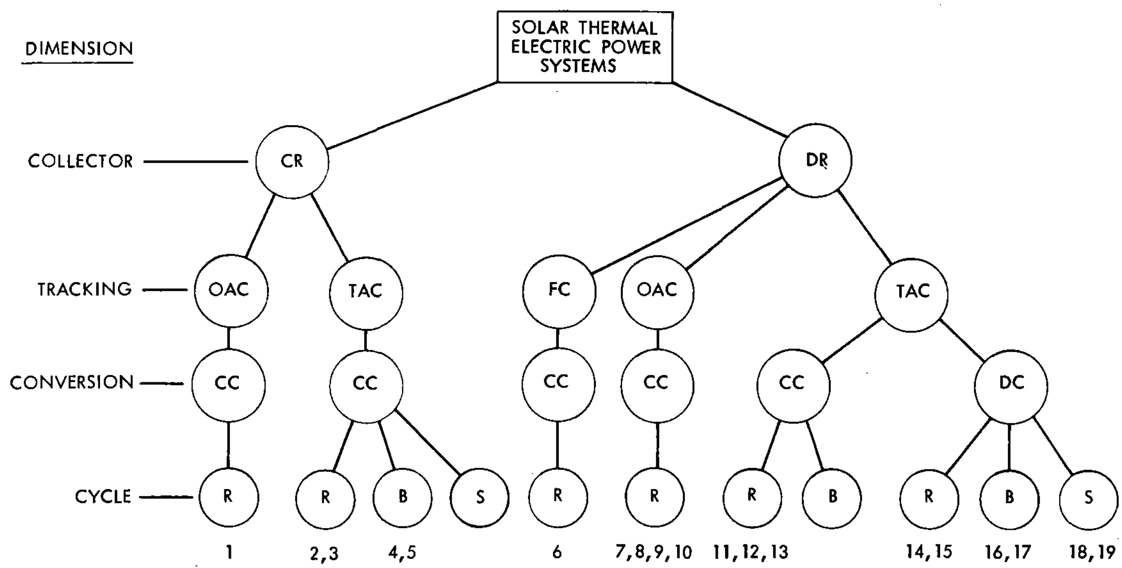
The purpose of Section II was to give the reader a feeling for the technology issues that impact the design of solar thermal power systems. As was probably apparent, there are several different technologies which may be chosen in the design of subsystems and in the final concept of a complete power system. The selection of a particular system concept for research and development (R&D) will depend on how well the concept meets the forecasted needs of its application.

It is the current dilemma of research and development that no power system concept appears significantly superior to warrant abandonment of other avenues of study. Furthermore, more than one concept may be necessary to meet a variety of energy needs. Consequently, several solar thermal power system concepts are undergoing simultaneous research and development. This section will provide an overview of these multiple avenues of experimentation, focusing only on the higher temperature solar thermal systems.

When examining solar thermal technology, it is convenient to breakdown the entire field along four dimensions associated with the type of collector and power conversion subsystems. These four dimensions represent the types of collector, tracking, conversion, and thermodynamic-cycle subsystems.

Two concepts are associated with the first dimension, the type of collector subsystem: the central and distributed receiver concepts (Section II-A). The second dimension, the type of tracking, includes fixed, one-axis or two-axis tracking systems. Central and distributed receiver concepts represent two distinct schools of thought in the solar thermal field regarding the cost trade-offs of energy conversion and transport. Tracking represents the different potentials for higher system efficiency as well as capital costs. The third dimension associated with the power conversion subsystem is again the central or distributed conversion concepts (Section II-A). The fourth dimension is the type of thermodynamic cycle employed: Rankine, Brayton or Stirling. Central and distributed conversion concepts are restricted by the type of collector; distributed conversion is practical only with a distributed receiver system. The type of cycle represents the potential for higher system efficiency and the need for high temperature collectors. Figure 3-1 graphically represents the breakdown of the field of solar thermal power systems along these dimensions.

If all combinations of the four dimensions were feasible, over 48 different solar thermal concepts would be possible, but basic technological incompatibilities reduce this field to the concepts shown in Figure 3-1. Central receiver systems preclude use of a fixed collector, simply because a central receiver infers that some focusing and concentration is employed which requires tracking. As stated above, distributed conversion only makes sense with a distributed receiver system; furthermore, fixed or one-axis tracking distributed receiver systems typically generate lower temperatures that make small distributed heat engine systems economically and technically



CR - CENTRAL RECEIVER
DR - DISTRIBUTED RECEIVER
OAC - ONE AXIS COLLECTOR
TAC - TWO AXIS COLLECTOR
FC - FIXED COLLECTOR

CC - CENTRAL CONVERSION
DC - DISTRIBUTED CONVERSION
R - RANKINE CYCLE
B - BRAYTON CYCLE
S - STIRLING CYCLE

1. FMC Corporation - central linear receiver concept
2. McDonnell Douglas - 10 MWe central receiver project, Barstow CA
3. McDonnell Douglas - 1 MWe central receiver, PFTEA EE1 concept
4. Boeing - central hot air receiver concept
5. Dynatherm - central hot air receiver concept
6. Argonne National Lab - compound parabolic collector
7. Acurex Aerotherm - parabolic trough collectors - Coolidge Arizona 150 kWe
8. Hexcell - parabolic trough - Gila Bend Arizona
9. General Atomics - fixed faceted mirror collector, tracking receiver
10. Suntek - SLATS TM linear focusing mirror array
11. General Electric - 1 MWe dist. receiver cent. conversion system, PFTEA EE1 concept
12. General Electric - solar total energy
13. E-Systems - fixed mirror distributed focus
14. JPL Thermal Power Systems, PFDR Project - 15 kWe dish Rankine study
15. Omnium G - dish Rankine system
16. JPL Thermal Power Systems PFDR Project - 15 kWe dish Brayton study
17. JPL Thermal Power Systems, PFTEA Project - EE2
18. JPL Thermal Power Systems, PFDR Project - 15 kWe dish Stirling study
19. Ford Aerospace and Communications - 1 MWe dist. receiver cent. conversion system, PFTEA EE1 concept

Figure 3-1. Breakdown of Solar Thermal Electric Power Systems impractical for conversion cycles other than Rankine. Presently, the small Stirling engines which have been developed are limited to use in distributed power conversion systems. However, the future does not preclude the development of large Stirling engines. Observing these above restrictions, only the 11 concepts shown in Figure 3-1 remain.

Many R&D projects and experiments currently are exploring these concepts. As shown by the list in Figure 3-1, several variations of one concept are possible. Selection of a superior concept is the subject of many studies, but as yet no concept has been proven superior. The final selection probably will have to await actual hardware demonstrations. However, studies have indicated that point-focusing (two-axis) central receivers and point-focusing (two-axis) distributed receivers appear to have a greater potential to achieve lower energy costs than the other concepts (Ref. 3-1).

B. MAJOR SYSTEM CONCEPTS

The purpose of this section is to present the concept of a complete solar thermal power system. Although specific systems and materials are mentioned, their use is meant only as an example. There are several other systems under current development not mentioned which use the same basic principles but different technologies.

1. Point-Focusing Central Receiver Systems

Central receiver systems are characterized as using a two-axis central receiver collector subsystem with a central power conversion subsystem. Two such concepts are under study. One is the 10 MWe power system at Barstow, California. Another is one of the three 1 MWe system concepts considered for use in the PFTEA Engineering Experiment No. 1 (EE1).

The McDonnell Douglas 1 MWe central receiver concept proposed for PFTEA EE1 is pictured in Figure 3-2. The complete system is made up of the collector, the power conversion, the energy transport and the energy storage subsystems as stated previously. A schematic of a central receiver system is shown in Figure 3-3.

The collector consists of a concentrator and a receiver. The concentrator is comprised of a field of two-axis tracking heliostats which direct insolation to a tower-mounted receiver. The heliostat field is located north of the receiver tower as shown in Figure 3-2, but may surround the tower in larger systems. This concept requires about 10 acres of land per MWe. The heliostat shown in Figure 3-4 is based on the design being developed by McDonnell Douglas for the DOE Central Power Program, 10 MWe central receiver pilot plant. Each heliostat is mounted on a pedestal with azimuth and elevation drives. The reflecting surface consists of rectangular glass mirrors mounted on either side of the pedestal with approximately 50 square meters of reflecting area for each heliostat. Other reflecting surfaces, such as plastics, are also possibilities.

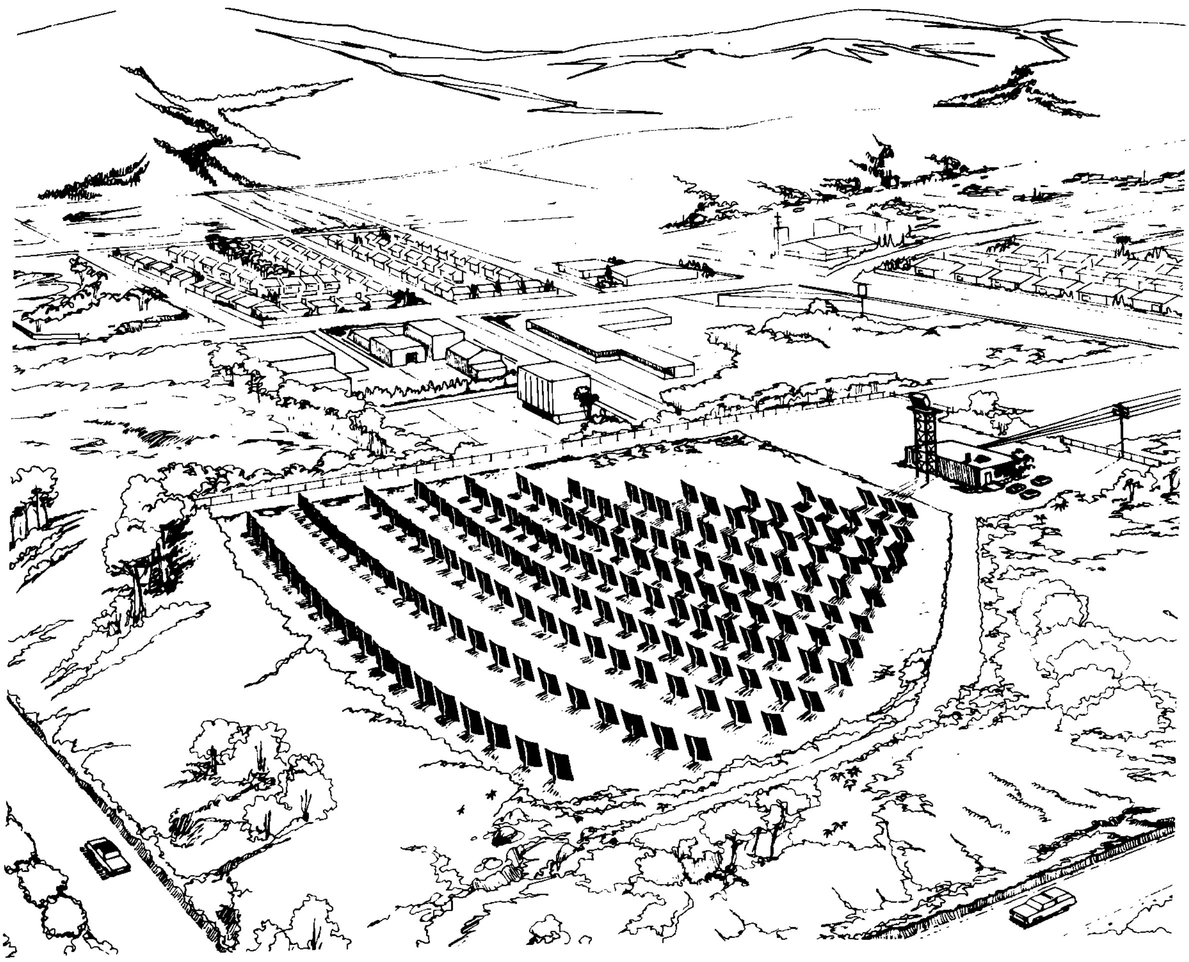


Figure 3-2. Central Receiver System Concept for EE No. 1

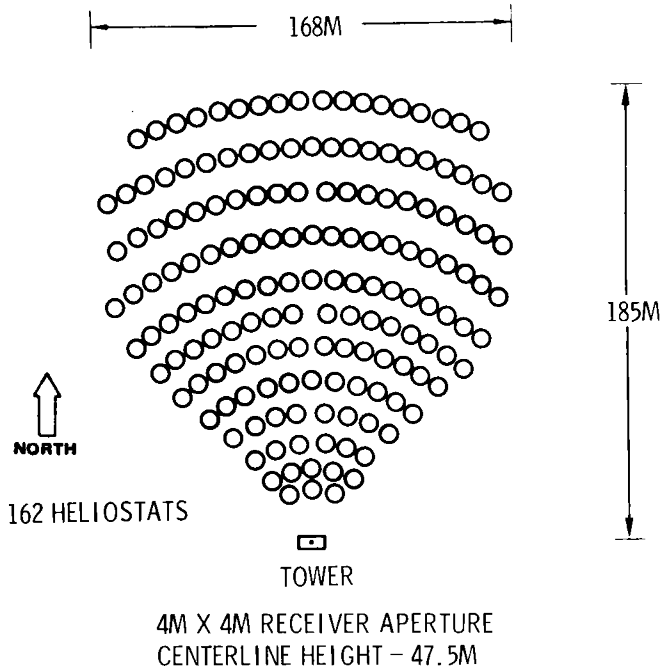


Figure 3-3. Schematic Diagram of Central Receiver System

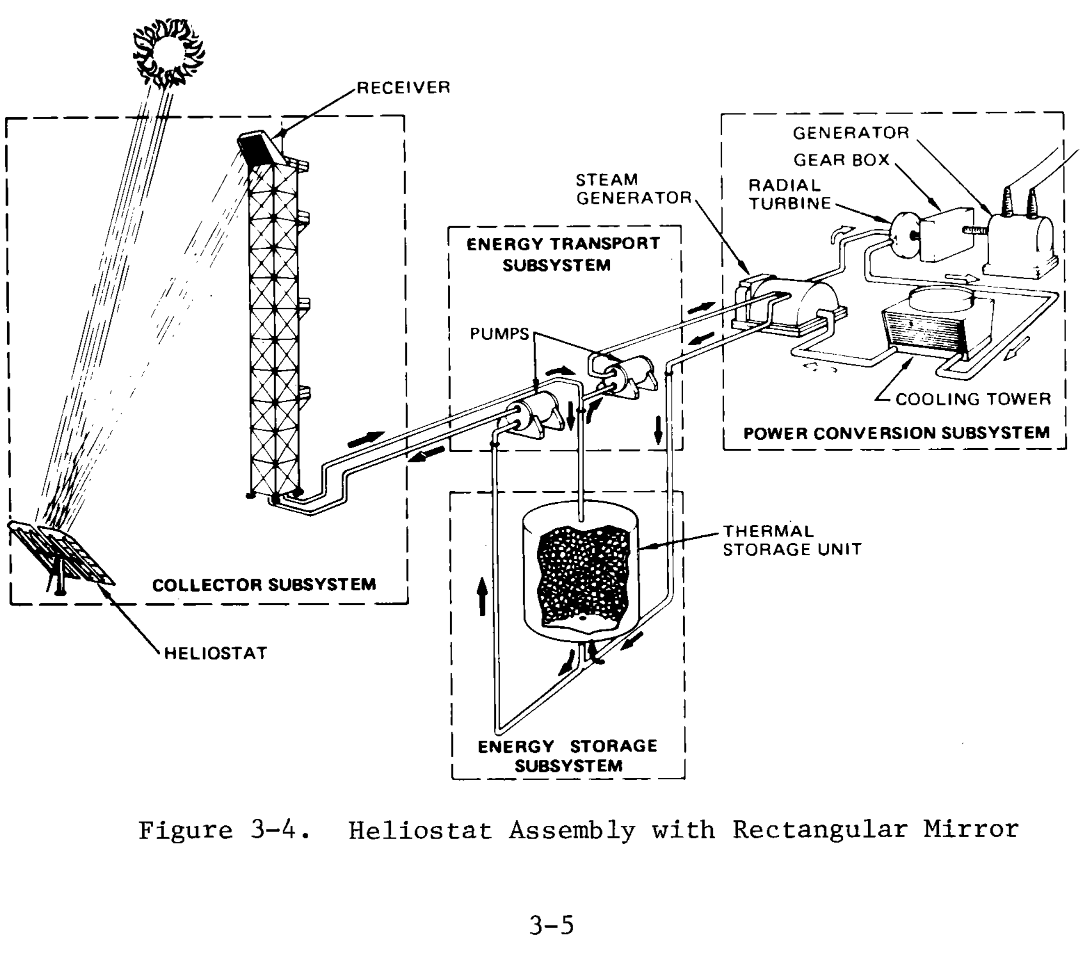


Figure 3-4. Heliostat Assembly with Rectangular Mirror

The receiver is mounted on an open frame steel tower supported by guy wires for this 1 MWe design, but other construction designs are also possible. Solar radiation concentrated by the heliostat field is absorbed by exposed piping within the receiver, heating the Hitec fluid used in the energy transport subsystem.

The energy transport subsystem utilized Hitec fluid, a low melting temperature mixture of salts, to transport thermal energy from the receiver to the power conversion subsystem. As shown in Figure 3-3, the hot Hitec, at about 510° C, is pumped to either the energy storage unit for use later, or to the steam generator unit to produce steam. Cold Hitec is pumped back to the receiver. Other thermal transport systems, such as steam, are quite feasible but interfacing with storage may cause problems.

Steam produced from the steam generator at approximately 480° C, drives a steam Rankine cycle turbine which in turn drives a gearbox and electrical generator to produce electricity. Waste heat from the turbine is rejected by a wet cooling tower. The nominal output of the EE1 power conversion unit is 1.1 MWe of which 0.1 MWe powers parasitic loads, such as pumps and controls. The net output is, therefore, 1 MWe. Brayton engines are another alternative for power conversion, however Brayton engines require high temperature gas transport subsystems which are feasible for only short distances. Mounting large engines on the receiver tower may not be practical.

The energy storage unit acts as an accumulator by storing thermal energy produced in excess of the energy needed by the power conversion subsystem. The stored energy is used when the power conversion subsystem requires more energy than the receiver can deliver during cloud blockages or at sunset. The storage unit uses the dual media technique which consists of a large tank with 75% of its volume filled with a rock/sand mixture. The sensible heat of the rock/sand mixture stores the thermal energy as the hot Hitec mixture is pumped through the storage tank. The tank, for the EE1 system, is large enough to hold 9 MWhr of thermal energy which can run the solar plant for 3 hours at the rated power of 1 MWe.

The expected system efficiency of systems similar to EE1 is 18.5%. Larger systems with bigger and more efficient power conversion units and more advanced technology will raise this value up to 30%. Central receivers utilizing advanced technologies such as Stirling engines in the years 1990 to 2000 may achieve 40% to 45% efficiency.

The initial capital costs of central receivers is fairly high. McDonnell Douglas estimates its 10 MWe Barstow design at $2200/kWe (1977 $). Other estimates for similar designs reach $5500/kWe. The Sandia Corporation estimate for the 10 MWe Barstow installation is $10,000/KWe (Ref. 3-2). Nuclear plants, by comparison, are about $1000/kWe (1977 $). It should be emphasized that these are initial experimental costs. Commercial designs will employ mass-production techniques to reduce costs. Studies that assume a 1990-2000 start-up time, mass production and high efficiency engines give ranges of $800 to $1800/kWe with $1300/kWe as the most likely estimate (Ref. 3-3).

2. Point-Focusing Distributed Receiver Systems

Point-focusing distributed receiver (PFDR) systems are characterized as systems with a field of two-axis tracking parabolic dish concentrator-receivers. Two options for power conversion are feasible. Central conversion uses an extensive thermal transport subsystem to collect heat generated at the receivers and deliver it to a large central power conversion facility. Distributed conversion refers to locating a small heat engine and generator at or near the receiver of each dish, minimizing the thermal transport subsystem, and generating electricity at each dish.

a. Distributed Receiver with Central Conversion. An example of a PFDR system with central conversion is the 1 MWe system concept proposed by General Electric for the PFTEA Project's Engineering Experiment No. 1 (EE1).

The General Electric system concept, pictured in Figure 3-5, is comprised of a collector field of approximately 200 to 250 two-axis tracking, parabolic-dish reflecting concentrators. One design option is to enclose each concentrator within an air-supported transparent enclosure to eliminate wind loading and reduce weather induced mirror degradation on the concentrator. Each dish concentrates incident solar radiation on a receiver-boiler mounted at its focal point. Steam from the receiver-boilers is transported to the central power conversion unit by insulated pipes.

Figure 3-6 showed the construction of a dish. Parabolic segments are mounted on a ring support structure to form an approximately seven meter diameter dish. Each segment is fabricated from an aluminum honeycomb sandwich core with a reflecting mylar surface. Coarse tracking is controlled by a central computer with a closed-loop sun sensor for precision tracking of the sun.

As stated previously, one design option is to protect a dish module from wind loads and weather by a transparent enclosure. The enclosure is constructed of a flexible transparent plastic hemisphere supported by internal air pressure from a small blower. Three tubular step frames might provide lightning protection and support during air-system-off periods. The enclosures may transmit only 86% of incident solar energy; weight and material costs saved on the concentrators would have to compensate for the reduced efficiency.

The receiver is mounted at the focus of the concentrator. One option is to use a potassium heat pipe with ball-shaped absorbing surface at the dish focal point to receive the concentrated solar energy. Heat would be conducted up the heat pipe to a series of boiler tubes thermally coupled to the heat pipe. Another option would be to use a cavity type receiver/boiler. Superheated steam, at 510° C, is produced from feedwater circulated to the boiler.

The energy transport system collects superheated steam from each collector module and transports it to the power conversion unit; feedwater is redistributed back to each module in a similar fashion. To reduce thermal

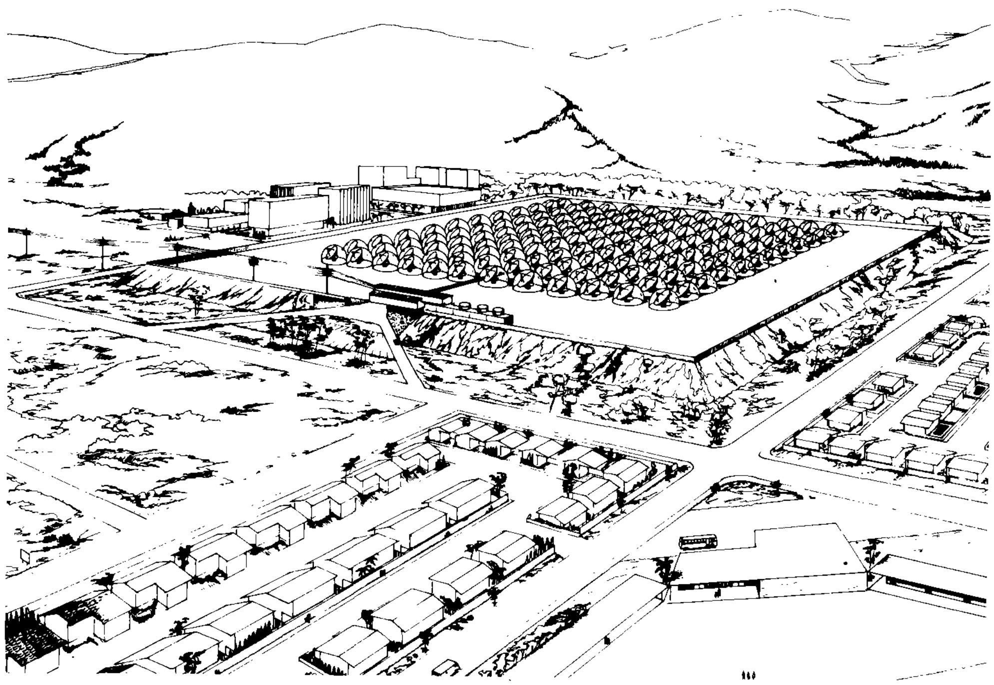


Figure 3-5. Point-Focusing Distributed Receiver System Concept for EE No. 1 with Central Conversion

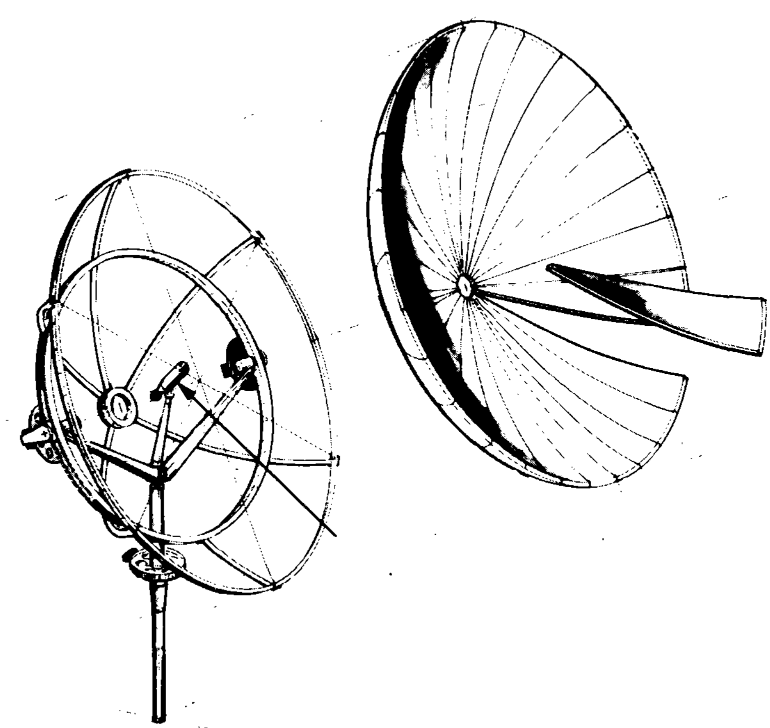


Figure 3-6. Collector Receiver/Boiler Assembly

losses on the long runs of piping, the feedwater and steam pipe sections are either sealed within a long vacuum jacket forming a reflective Dewar-type flask or may use heavy insulation, depending on cost.

The power conversion unit, shown schematically in Figure 3-7, consists of a 1,200 kW marine-type steam turbine, an electrical generator coupled to the turbine through a speed-reducing gear box, and all the supporting components. The turbine inlet steam temperature is at 480° C with pressure of 1200 psi. Electrical output is rated at 1,100 kWe of which 100 kWe is required for parasitic loads, to give a net output of 1 MWe. A steam accumulator is used to maintain turbine speed at no-load during intermittent cloud blockages. Waste heat is rejected by a dry cooling tower. A battery storage system is used to achieve a 0.4 capacity factor, but thermal storage is also a possibility.

b. Distributed Receiver with Distributed Conversion. PFDR systems with distributed conversion, sometimes called dish-electric systems, have small heat engine-generator units mounted at the focus of each dish. Electrical collection is simpler and more efficient than central heat collection. Energy storage can be located either on the power plant site or anywhere in the power system grid. The energy storage may be of any type that is efficiently and economically connected to the electrical power grid. Advanced battery systems and pumped hydro storage are some of the feasible storage technologies.

Another concept in this category is the multi-dish system, which connects up to seven dish collectors to a single larger engine. The entire system is comprised of many of these collector-engine groups. The advantage here is the capability of using high temperature thermal storage without use of a long thermal transport piping.

Any of the three principal conversion cycles, Rankine, Brayton or Stirling, may be employed in dish-electric systems. Dish-electric systems employing Stirling cycles are particularly attractive because they offer the highest potential system efficiencies.

An example of a dish-electric system is the 1 MWe concept prepared by Ford Aerospace and Communications Corporation, Aeronutronics Division for the PFTEA Project Engineering Experiment No. 1 (EE1). The Ford Aeronutronics concept, pictured in Figure 3-8, consists of a collector field of approximately twenty parabolic dish concentrator modules. A receiver unit and a power conversion unit are mounted on each dish near the focus. Figure 3-9 depicts a module.

Electricity is generated at each collector and transported to the station power conditioning unit providing connection to the utility grid. Figure 3-10 schematically represents the entire system.

Each concentrator module is about 8 meters in diameter and similar in construction to parabolic dish radio antennas. The concentrator is mounted on a gear-driven turntable for azimuth tracking. A linear actuator provides elevation tracking. A sun sensor provides closed-loop tracking control.

The receiver unit and power conversion unit are both mounted near the concentrator focus. Figure 3-11 shows the arrangement of the receiver and power conversion units. The cylindrical cavity type receiver utilizes liquid sodium as a heat transfer medium and operates at 800° C.

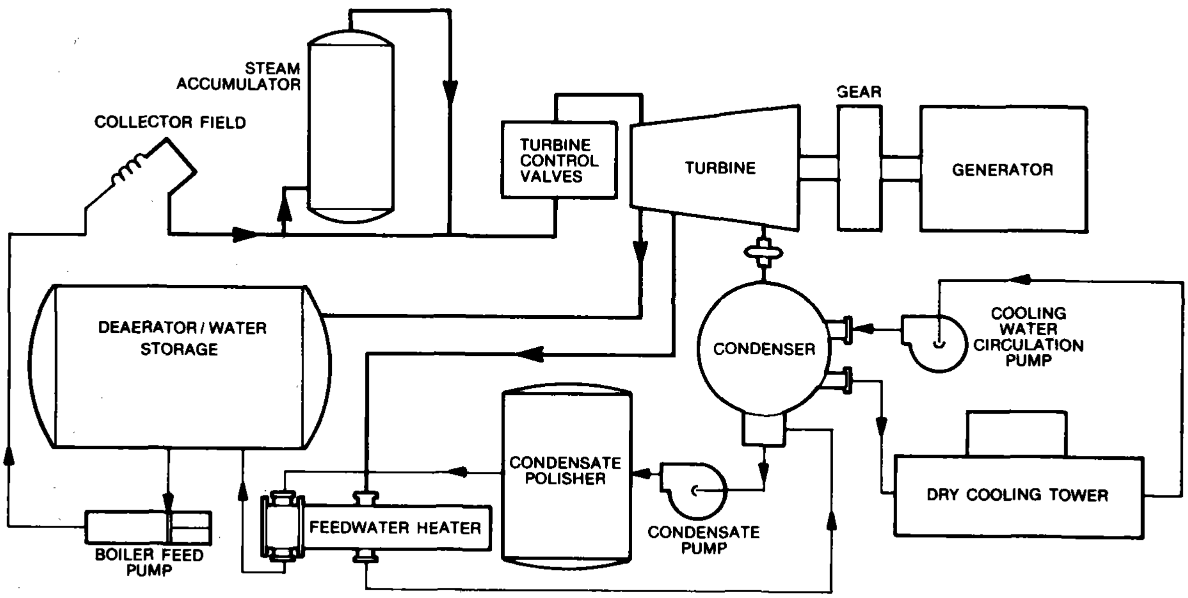


Figure 3-7. Simplified Process Flow Diagram, 1 MW Power Conversion Subsystem

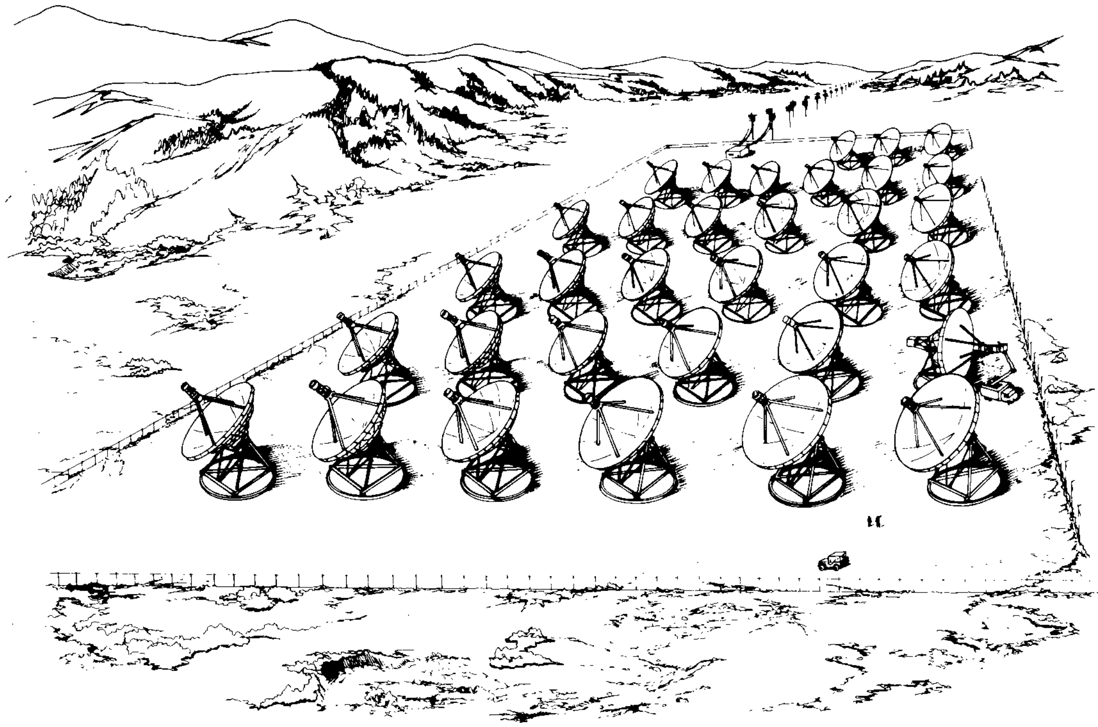


Figure 3-8. Point-Focusing Distributed Receiver System Concept for EE No. 1 with Distributed Conversion

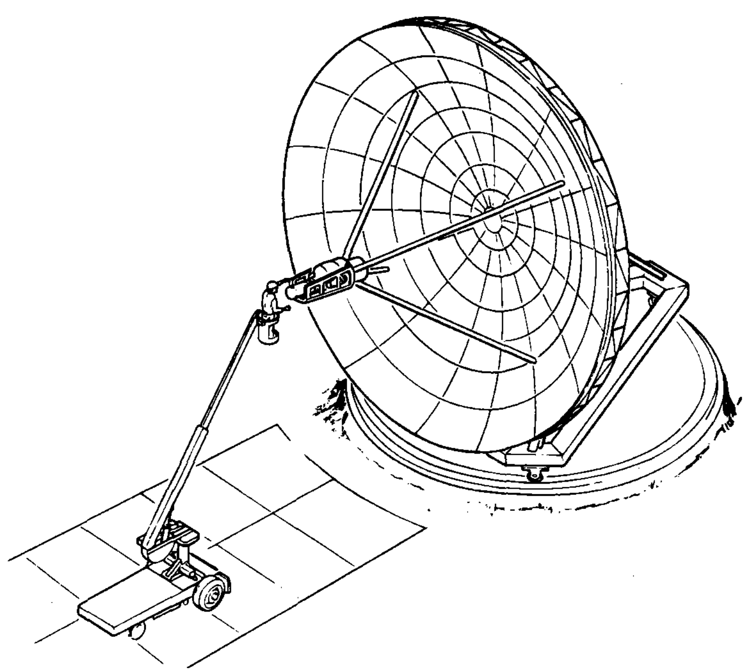


Figure 3-9. Distributed Conversion Power Module

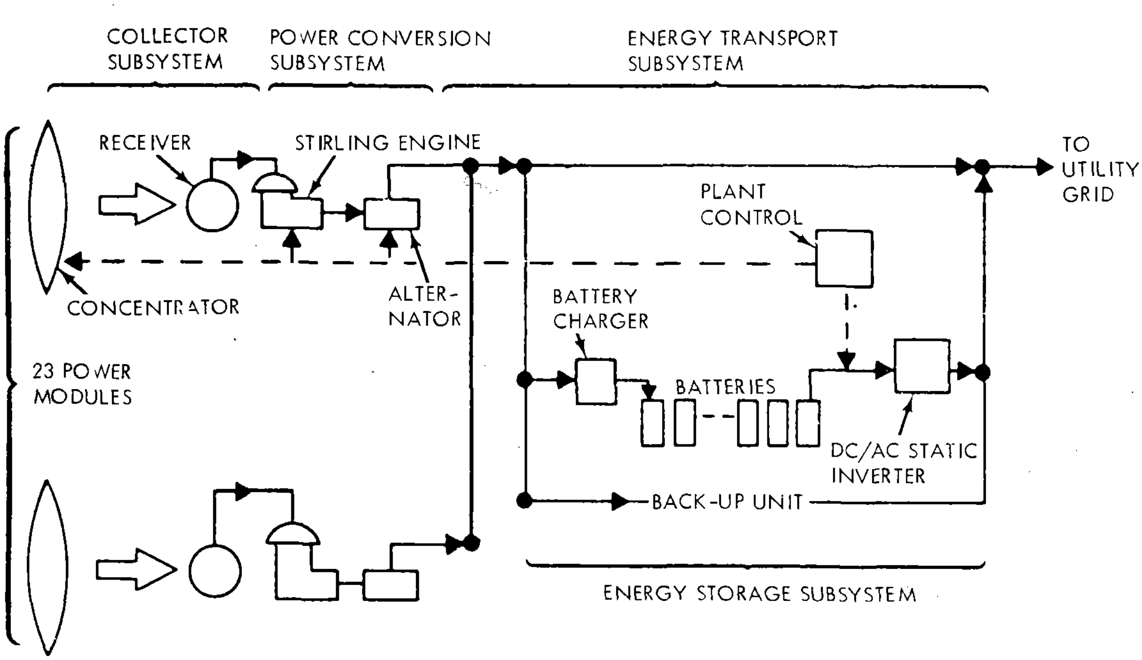


Figure 3-10. System Schematic Diagram for Dish-Electric System

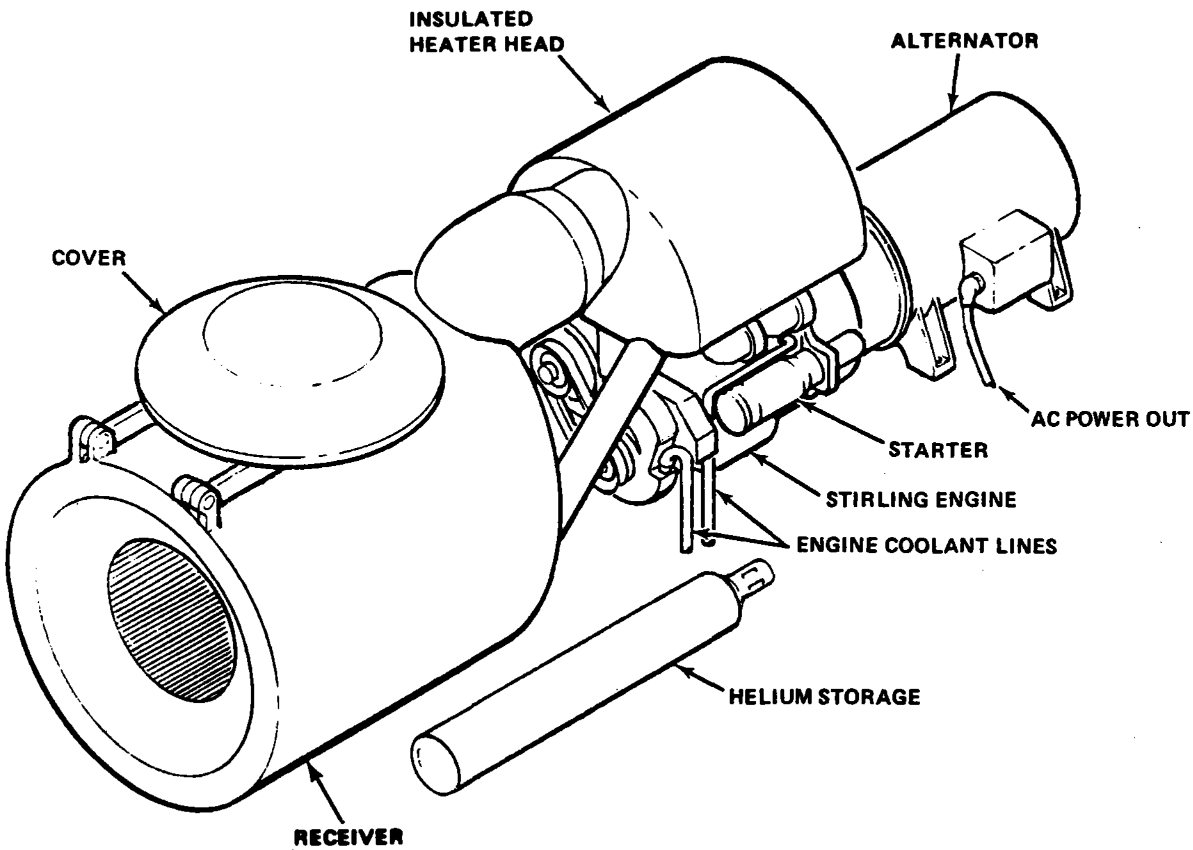


Figure 3-11. Dish-Electric Receiver and Power Conversion Unit

The power conversion unit consists of a reciprocating Stirling cycle heat engine and alternator to produce electricity. The heat engine is a P-75 Stirling cycle engine produced by United Stirling of Sweden (USS), modified for a sodium heat source and using helium as a working fluid. Waste heat is conducted to a conventional water/ethylene glycol heat exchanger mounted behind the concentrator reflecting surface. The engine operating point efficiency is 39% with a shaft output of 58 kWe at 1800 rpm. The electrical output is about 53 kWe per module. Parasitic losses and electrical collection and transportation losses reduce the net output to about 50 kWe per module to the utility grid. A lead-acid battery storage subsystem is required to achieve a 0.4 plant capacity factor. Ac-dc and dc-ac converters are used to connect the batteries to the utility grid.

Advanced dish-electric systems are forecast to achieve up to 40% to 50% efficiency. These systems would most likely involve advanced heat engine technology, probably Stirling cycles, operating above 800° C.

3. Comparison of Alternative System Concepts

The objective of the R&D function is to develop solar thermal power systems that are technically, economically and institutionally feasible. An economically feasible power system is competitive with other forms of energy production in terms of cost. An institutionally feasible power system is a system in which non-price factors are acceptable to the user, such as environmental impact. Finally, a technically feasible power system is both an effective and producible system within the above constraints.

The research and development of solar thermal electric power systems is just beginning. Many types of solar thermal system concepts have been identified and are being analyzed throughout the country. However, at this stage, it is still unclear as to which designs are the most effective and producible. The primary difficulty in these assessments is not determining a system's performance, but in determining accurate cost estimates of designs and potential production cost reduction scenarios. Therefore, it is difficult for research and development to make the appropriate trade-offs involving cost, performance and production designs.

The approach taken most often in the R&D process is to determine several alternative solar thermal system concepts and assess each alternative with respect to the feasibility constraints. The most promising alternatives are chosen for further in-depth analysis; the best are chosen for pilot production, demonstration tests and eventually full-scale production.

A study performed at JPL (Ref. 3-1) attempted to estimate the performance and cost of promising subsystem technologies and generate a set of promising solar thermal power systems. A comparative evaluation of the most promising complete systems and some of the results are presented in Table 3-1. Each system represents an advanced solar thermal power system implemented in the 1990 to 2000 time-frame. Major assumptions for these systems include cost reduction via mass production and access to highly advanced, high-efficiency conversion subsystems. The first system, central receiver/Rankine, is used as a baseline system for reference the capabilities of near-term technology.

Table 3-1. Comparison of Major System Concepts

Configuration (10 MWe Capacity) (0.4 Capacity factor)				Capital Cost	System Efficiency	Energy Cost	
Collector	Conversion	Transport	Storage	(1977 $/kWe)	(%) (not through storage)	(1977 mills/kWhr)	Note
Central Receiver (heliostat)	Central 600°C Steam Rankine	Thermal heat trans. oils	Sensible heat dual media rock/oil	1320	30	102	2
Central Receiver (heliostat)	Central 820°C Stirling	Thermal liquid metal	Sensible heat liquid metal	1250	40	74	1
Central Receiver (heliostat)	Central 820°C Open Cycle Brayton	Thermal liquid metal	Sensible heat liquid metal	1230	37	79	1
Distributed receiver (dish)	Distributed 1000°C Stirling	Electrical	Redox Battery	1120	45	63	1
Distributed receiver (dish)	Distributed closed cycle Brayton 1100°C	Electrical	Redox Battery	1140	44	75	1
Distributed receiver (dish)	Multi-dish 820°C Stirling	Thermal liquid metal	Sensible heat liquid metal	1000	40	63	1

NOTE: 1) An advanced system which assumes cost reduction by mass production and highly advanced, high efficiency engines for the 1990-2000 year time frame.

2) Baseline system representing near-term technology for reference

The central receiver/Stirling system shows the lowest energy cost of the central receivers, primarily because the Stirling engine has the highest projected efficiencies. The heliostat-Brayton system achieves a slightly higher energy cost since the Brayton engine is projected to have lower efficiencies than the Stirling.

The parabolic dish/Stirling with an 1000° C receiver and focal-point mounted engine provides the lowest energy costs, again primarily because of the high estimated efficiencies of Stirling engines.

The parabolic dish/Brayton with small 20 kWe focal-point mounted engine provides substantial reductions. These reductions are not as low as the Stirling system because the cycle efficiency of small Brayton engines is lower than the Stirling engine. As discussed previously, Brayton engine efficiency drops as size decreases whereas Stirling engines maintain nearly constant efficiency with variations in size.

The multi-dish/Stirling with liquid metal transport and storage attains nearly the same energy cost as the parabolic dish-Stirling with small focal-point-mounted engine and battery storage. The primary reason is that liquid metal storage is projected to be more efficient and cost-effective as compared to battery storage, particularly for systems using Stirling engines which efficiently convert stored heat to electricity.

The central receiver and distributed systems are comparable in terms of potential for providing advanced systems that can approach system cost targets. Uncertainties in the projected costs and performance are such that it is difficult to categorically choose either of the two basic approaches as technologically or economically superior.

C. APPROACHES TO COST REDUCTION

A major barrier holding back the commercial use of solar thermal power systems is the capital cost of the system and the subsequent high cost of energy generated by the power system. Solar thermal power systems today have capital costs $5000/kWe to $16000/kWe. If society does not highly value the environmental and other social characteristics of these solar systems compared to coal and nuclear systems, then capital costs approaching $1000/kWe and energy costs of 50 to 60 mills/kWh (1978 $) may be necessary before successful commercial applications of solar thermal power systems may begin in the utility sector. Therefore, cost reduction is seen as one of the most critical requirements in the development of solar thermal power systems.

1. Technical Approaches to Cost Reduction

a. Research and Development. The contributions that R&D can make towards the cost reduction of solar systems involve a combination of selection of optimal technologies and innovative design. Selecting technologies requires careful estimation of the potential performance, the expected costs, as well as the development risks of the many alternative system and subsystem concepts. A difficult choice is then made to invest scarce R&D resources in the development of concepts and subsystem technologies which appear to offer the greatest return in cost reduction. This decision may be critical in determination of the eventual success of solar thermal power systems.

Innovative design is less critical, in the sense that once a particular concept or technology is chosen, innovative design helps it achieve its true potential for performance and cost reduction. Innovative design may either enhance performance causing a reduction in the cost of energy, or reduce material content causing a reduction in capital cost. An example is the use of plastic bubbles to eliminate wind loading on collectors, reducing the structural constraints on the collector and the amount of material required to produce it.

b. Manufacturing. Cost reduction in the manufacturing of a solar thermal power system may be achieved as a result of mass production. Mass production is expected to be a major factor in solar system cost reduction. Automotive-type production lines can spread the fixed production costs over a large number of units reducing the overall unit cost to mostly the cost of materials and labor. If R&D can also reduce the materials content of a system, then substantial cost reduction may be realized.

In fact, coordination of R&D and manufacturing studies is necessary to capture the full benefit of mass production. Figure 3-12 represents the effect of mass production and learning curve behavior on power conversion systems. As can be seen, smaller units have a greater cost reduction potential than larger units. Given a market for solar systems at so many MWe/year, there may exist an optimal size of conversion unit which achieves the lowest overall market cost.

c. Installation. A very limited number of solar thermal power systems is designed to use unspecialized installation techniques in the site installation of a system. High labor costs are incurred, but these are rather insignificant compared to the overall capital cost of these initial systems. However, as capital cost of solar systems are reduced, installation will become an increasingly significant cost factor.

Obviously, one way of reducing installation costs is the use of specialized on-site equipment and automated techniques to reduce labor cost. However, the number of systems installed per year will determine whether investments will be made in specialized equipment. Cost reduction via innovative design to reduce construction time and labor is also possible. Reduction in construction time shortens the time that capital is tied up in unproductive assets, thereby lowering the cost of energy.

A further method of cost reduction has been suggested by the use of modular systems. Modular systems are comprised of arrays of individual power producing modules. As modules are installed and made operational, power could be generated and revenues collected during construction, again lowering the final cost of energy.

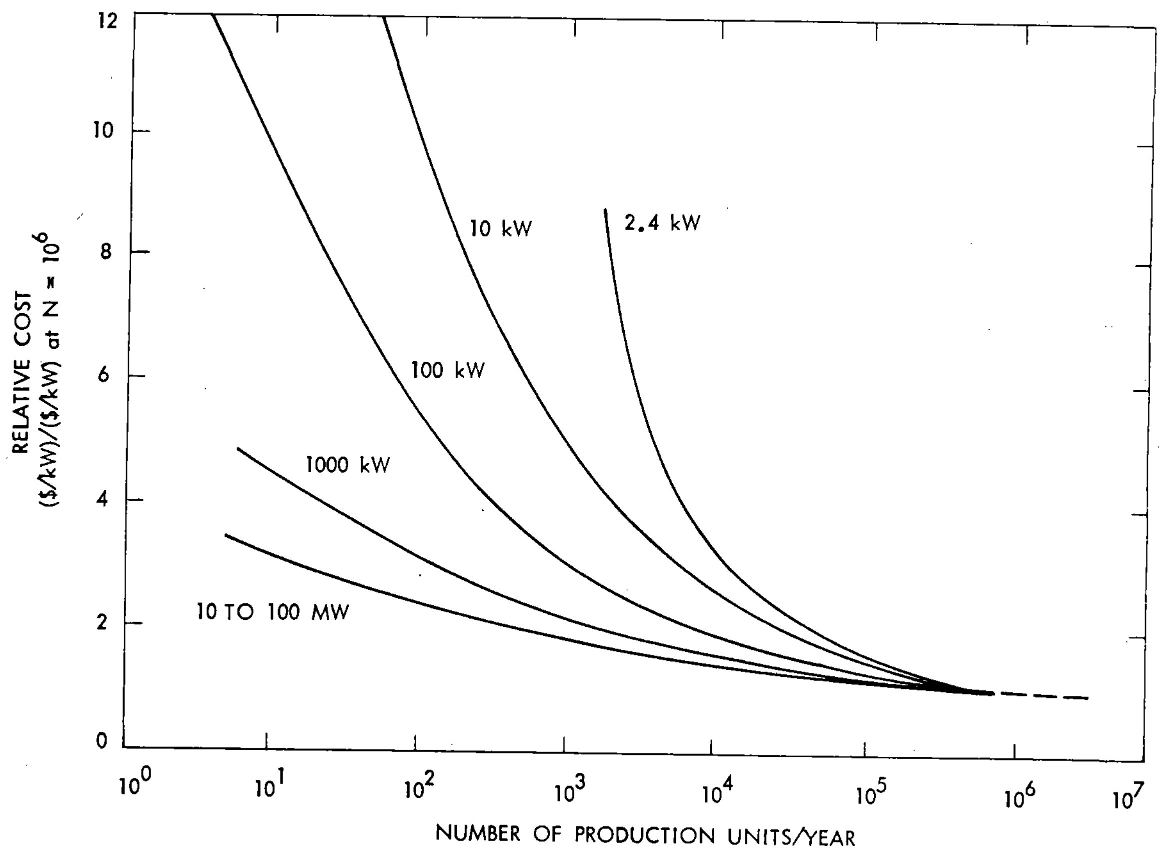


Figure 3-12. Suggested Model for Capital Costs of Energy Conversion Systems in Volume Production

d. Operations and Maintenance. Operations and maintenance (O&M) costs are distributed costs (Section II. C. 4) and as a result have almost a direct impact on the cost of energy. Maintenance is usually partitioned as scheduled versus unscheduled maintenance. Operations contains several accounts which may include personnel, special materials and insurance. Innovative design may play a major role in reducing these costs. Increased reliability and safety may reduce unscheduled maintenance and insurance costs. Thoughtful design may reduce collector cleaning costs, engine maintenance, the number of operating personnel and other costs.

Estimates of O&M costs are very uncertain because there are only a few installed solar systems and these have not been operational for a long enough time to accurately assess O&M costs and their impact on energy cost.

2. Critical Research and Development Issues

a. Selection of Optimal System Concepts. As stated in Section III. C. 1-a, the choice of a preferred system concept is a critical decision in the research and development of solar thermal power systems. The choice of criteria on which to base the decision, and the methodology to make the decision, are important questions in themselves. Once preferred concepts are identified, a strategy must be developed to allocate R&D resources and effort in an optimal way in order to maximize the potential for successful commercial applications of solar thermal power systems.

b. Modularity. As referred to in Section III. C. 1-b, the size of a module becomes important when determining the effect of manufacturing cost reductions. Modularity also affects other system attributes such as reliability and installation costs. It is preferable that the issue of modular versus integral (or centralized) systems be resolved early so that the R&D effort may be concentrated on either type of system without increasing the risk of development failure. However this may not be possible until further into the research or development stage.

c. Conversion Efficiency. Currently, the trend is toward increased research and development of advanced systems with the highest potential conversion efficiency so that the collector area will be reduced and capital costs lowered. However, these trade-offs between efficiency, commercial cost, R&D cost, and time are difficult and currently unresolved issues.

d. Land Use and Site Preparation. Two critical issues in the viability of solar thermal power systems are land use and site preparation costs. Solar systems require large amounts of area for their collector fields, as compared to more compact fossil fuel power sources. The use of large amounts of land becomes a critical issue when solar systems are used in applications where land or clear sun visibility is scarce or expensive. Such situations would occur in urban areas and hilly sites.

Further compounding the issues is the cost of site preparation. These cost accounts would include land survey/soil testing, site grading, sewers, access roads, fire protection, building/collector foundations and many others. Estimated costs for site preparation have ranged from \$900/kWe for small systems and \$200/kWe for large systems (Ref. 3-4). These are significant amounts when compared to the objectives of \$1000/kWe for capital costs. Many of these site preparations are constrained by building codes and regulations which will prevent much cost reduction.

SECTION IV

ECONOMIC ISSUES IN THE DEVELOPMENT AND INTRODUCTION OF DISPERSED POWER SYSTEMS

Sections II and III described several technologies available for harnessing solar energy. The development and use of such technologies is worthwhile only if alternatives with familiar production techniques are unavailable or become more costly. The following subsection examines trends in national energy demand and supply, and evaluates the implications of these trends for fuel prices and for a combination of energy inputs. Simultaneously, fuel mix and price changes will have widespread impacts on the energy supply sector, the environment, capital costs, and the economy. These impacts, and the questions that they raise, are explored in this section. Although the issues are complex and subject to great economic uncertainties, solar thermal systems have possibilities for beneficial use in several areas.

Subsection B considers those markets which have the greatest promise as solar thermal users, and lists the advantages and disadvantages of dispersed power systems for each market. The final decision to invest in solar capacity will depend on a large number of unresolved problems: the cost of solar power and its alternatives, the financial environment, institutional incentives, regulations, informational problems, market biases, and uncertainty. These issues are analyzed in subsection C; a concluding subsection outlines the work which remains to be done.

A. THE ENERGY SYSTEM IN TRANSITION

To assess the potential usefulness of developing solar thermal systems, it is necessary to evaluate energy needs and outputs during the period in which solar power is being developed and tested. This requires a detailed set of energy supply and demand forecasts for the next fifty years; however, few predictions contain both the coverage and the detail needed. This study utilizes energy forecasts made by Data Resources, Inc. (DRI) for 1975-1990, and supplemented by Stanford Research Institute (SRI) beyond 1990 to 2022. While these forecasts rest upon some questionable assumptions (see Ref. 4-27 for an excellent summary of these data problems), they represent the most comprehensive and detailed projections currently available, and they are used in conjunction with JPL's expertise and judgment on energy pricing.

1. National Energy Trends

a. Demand Forecasts. Figure 4-1 shows how much of each fuel resource will be used to provide energy during the next half-century. Traditional power sources, such as petroleum, natural gas, and hydropower, are projected to have smaller shares of the energy market over time, although the actual amount of each resource used may increase because total demand is growing. Replacement fuels, such as coal and nuclear, will reduce the market share of oil, natural gas, and hydropower, because electricity production absorbs a growing percentage of national energy input needs.

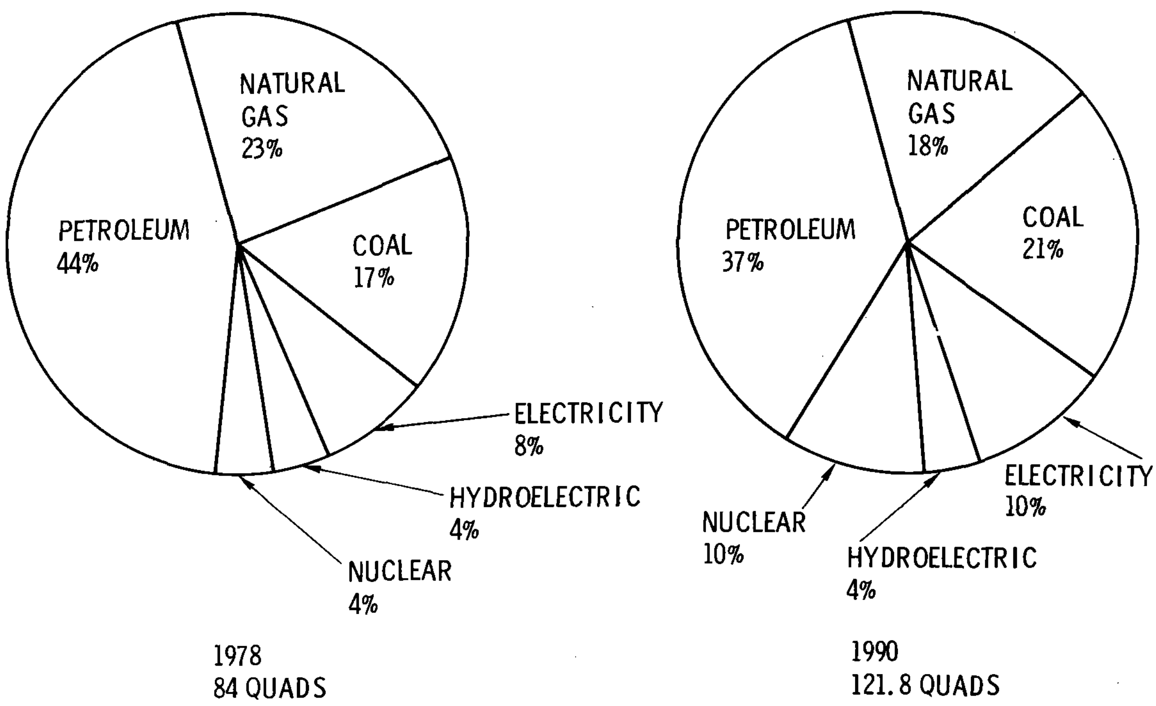


Figure 4-1. Aggregate Consumption by Energy Resource
(Source: Data Resources, Incorporated)

Figure 4-2 presents forecasts of energy consumption by sector. Electric utilities are (and will continue to be) the largest user of energy in any sector. Households, industry, and transportation will use growing quantities of energy, but their proportion of total usage will be overshadowed by utilities, as more and more power is supplied by electricity.

From these scenarios, it appears that increasing proportions of all energy consumed will be lost during conversion to electric power. Even though households, businesses, manufacturing, and transportation will represent smaller percentages of energy use, the total demand for energy resources in each sector will continue to grow. It is therefore necessary to see how closely suppliers can match expected demand; this analysis is described below.

b. Supply Forecasts. Unlike demand, domestic production of traditional fossil fuels (other than coal) will not continue to grow over time. There are many reasons for this: remaining fuel deposits are of poorer quality or less accessible, lags between discovery and production of any given resource are lengthy, production is carried out under environmental constraints, and there are many forms of uncertainty--about technology, market size, regulations, taxes, safety, and reliability. Each of these reasons leads to increasing costs and greater risks in developing energy resources. The prospects for production growth of each fuel type, as outlined by Hittman Associates, Inc. (Ref. 4-14), are discussed below.

Domestic oil production has been steadily decreasing and will probably continue to decrease unless significant changes take place within the oil industry. There are several sources of increasing costs to producing oil. One of these sources is exploratory drilling; the finding rate in drilling involves both risk and exploratory skill. It affects not only future supplies but prices required to pay back an investment. Also, secondary and tertiary recovery methods are more costly than primary methods. These non-primary methods will represent a growing percentage of oil production; a National Petroleum Council estimate (Ref. 4-21) places them at 65% of projected oil reserve additions. Use of synthetic petroleum resources (such as oil shale in the Green River area) may be preferred to increasing reliance on foreign imports, but they are environmentally damaging, costly, and have an undeveloped technology.

Additional natural gas supply depends on three things: gas well drilling rates, finding rates, and oil well drilling and finding rates. Since fewer oil wells are being drilled, and many of the major natural gas deposits have already been exploited, prospects for rising natural gas discovery are dim. Synthetic gas has been suggested as an alternative, but it has the same environmental, technological, and cost problems as synthetic oil.

Although the U.S. has almost 53% of the free world's coal resources, coal has gradually declined in importance as a major fuel. Restrictions on surface mining for environmental reasons, and restrictions on deep mining for health and safety reasons, have made increased production more costly. Clean air standards in major urban centers have led electric utilities and industry to convert from high sulfur coal to low sulfur oil as a fuel. Several factors will hinder increased coal usage in the future:

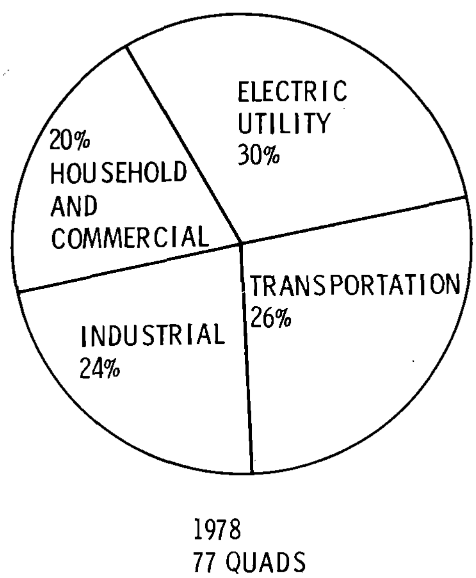


Figure 4-2. Aggregate Consumption by Sector
(Source: Data Resources, Incorporated)

- Manpower: This includes miners and mining engineers. It is estimated that 37,400 additional employees would be required to increase underground production by 38%.

- The need for improved mining technology to offset the Coal Health and Safety Act of 1969.

- Possible environmental restrictions on surface mining.

- The number of railroad hopper cars, and the efficiency of utilizing those cars.

- New techniques are needed for using high sulfur coal in power generation without air pollution: i.e., desulfurization by liquefaction, gasification, and stack gas cleanup.

Given these limitations, Hittman Associates (Ref. 4-14) has estimated a maximum feasible growth rate in coal usage of 5% per year until the end of the century.

Nuclear energy supplied for electric power generation will increase; however, installed capacity is difficult to predict because of technological, environmental, legal, and regulatory problems. These include problems with plant construction and operation, manufacturing techniques, administrative procedures, legal and licensing problems, and lead times which currently run more than eight years per plant.

Hydropower will continue to be a relatively minor contribution to total U.S. energy supply, since its full potential has largely been developed. There are so few suitable dam construction sites remaining that hydroelectric power will be a declining component of total U.S. energy production.

Given the constraints on domestic production of energy resources, it appears that a growing proportion of our energy needs will be filled by foreign imports. This trend is not implicitly "bad", since it means that cheaper resources (those imported from other countries) are being used before more costly domestic ones. However, this does leave the U.S. more vulnerable to international price increases or foreign export restrictions.

These energy use and price trends will have a wide variety of impacts on users, suppliers, the environment, investment, and employment. These impacts are discussed more fully in the next subsection.

c. Implications for Energy Prices and Input Mix. Using the analysis of the previous two subsections, a number of tentative conclusions may be drawn. Given an ever-expanding demand for energy, and a domestic production capability which is hindered by increasing costs, environmental constraints, regulations, and uncertainty, a number of things will happen:

- Clean energy fuels will command higher prices.

- As the relative price of traditional fuels increases, users will switch to the new, relatively cheap, substitutes.

- Since domestic production may continue to lag behind consumption, a growing proportion of national energy needs may be filled by foreign imports.

As traditional fuels, such as oil and natural gas, become less accessible or of poorer quality, the cost of extracting these fuels increases. When combined with environmental constraints, safety and reliability problems, regulatory uncertainty, and the many forms of risk facing producers, rising demand can only be met by higher prices. A JPL scenario of energy prices by Terasawa and Ugone (Ref. 4-16) using the DRI energy model shows that the real prices (1978 $) of fuels will continue to rise during the transition phase (until the year 2000), but at diminishing rates. Thereafter, prices and fuel outputs attain new equilibrium levels; see Figure 4-3 for a set of fuel cost scenarios by end user.

In response to rising relative costs and lower quality of traditional resources, users will decrease the energy intensity of production processes and switch to substitute forms of energy. Thus, while oil is expected to be the dominant fuel until the turn of the century, coal will dominate fuel pricing of energy forms thereafter, with synthetic fuels and nuclear power contributing increasing percentages of total energy needs. However, these alternative fuel forms are costly to refine and develop, and have larger amounts of risk associated with them. These substitutes will be used only as the rising price of traditional fuels exceeds the cost of developing and exploiting alternatives.

2. Major Issues in the Energy Transition

This section considers how energy trends outlined previously will affect each of the following topics: supply uncertainty, domestic energy supplies, pricing strategies, environmental considerations, capital costs, and employment.

As mentioned before, increasing reliance will be placed on foreign sources of energy, with a consequent increase in supply uncertainty. This creates two problems; first, the nation is made more vulnerable to foreign output restrictions and price increases; this will have repercussions on output, inflation, employment, and growth in the United States. Another problem is continuing balance of payments deficits, and the damage they do to the international value of the dollar. Although trade deficits are not a problem in and of themselves (lower dollar values create larger export markets, and give foreign countries an incentive to invest in the United States), they become a problem when foreigners lose confidence in the U.S. currency as an international store of value and begin massive speculations against the dollar. Thus, increased energy imports from abroad not only lead to more uncertainty in meeting domestic demand, they can also contribute to international instability of foreign exchange markets.

Since the rest of the world does not have an unlimited supply of cheap energy, part of the growing demand for energy inputs will simply result in higher energy prices. In addition to this demand-side pull on prices, cost will also rise due to efficiency losses. Because lower grade fuels will be developed, they require more energy and expense to extract and convert into

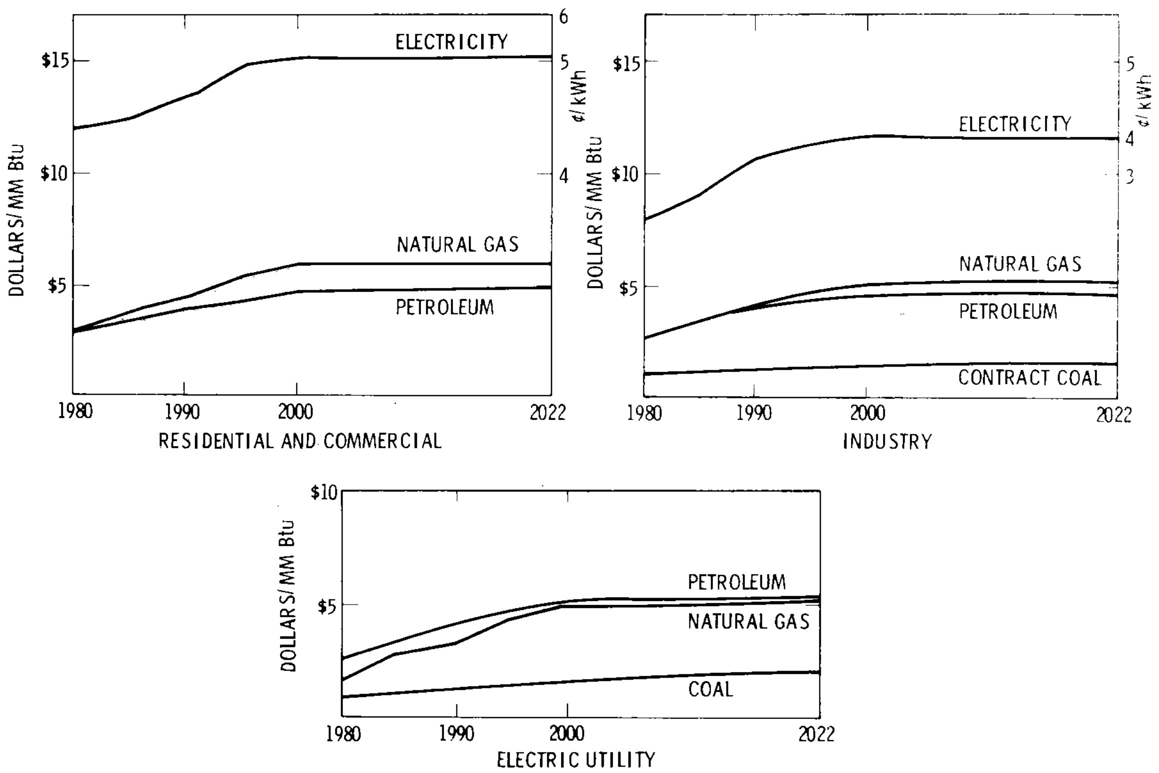


Figure 4-3. National Energy Prices, 1978 Constant Dollars (Source: Terasawa and Ugone)

usable fuels. Also, with increasing amounts of electricity production and nuclear fuel usage, power plants will become more centralized; while it is possible that larger plants could be more efficient because of lower heat rates, centralization may also lead to greater energy inefficiency through transmission losses.

A corollary effect of this centralization (in addition to transmission costs and energy losses) is a loss of flexibility in siting. Since centrally built power plants must be capable of handling current peak demand and have enough capacity for future demand, they tend to be large facilities with lots of extra capacity built in. These plants operate most efficiently at high load levels, but out-migration of firms or residents results in wasted capability. When facilities are built on such a massive scale, the number of sites available for power plant construction falls dramatically; also, changing over to other input fuels is a costly and difficult problem.

Difficulties in fuel changeover and centralization of facilities are just two of the factors contributing to higher capital costs. Energy resources are of poorer quality, and require more refining. Construction of large plants encounters greater lead-time problems for building; large nuclear facilities require a lengthy review process before a construction permit is issued. Thus, with higher capital costs and longer construction horizons, firms must worry about the safety of their capital investment and the willingness of investors to participate.

In an attempt to moderate these cost increases, utilities may try to reduce capacity demand by changing their energy pricing strategies. The current pricing structure is decreasing block tariffs; users pay a higher price for the first block of electricity than for the second block, even less is paid for the third block, etc. This rate structure can be defended on the grounds that initial use is most costly (it requires grid hook-up, billing, metering, maintenance, etc.), but incremental increases in power usage are not as expensive for the utility to provide. However, such a pricing scheme does not encourage as much energy conservation as would a rising price structure; also, the rates do not contain any incentives to cut back usage during periods of heavy demand, when the costs of providing energy are greatest. Adoption of new pricing strategies also creates problems and uncertainties. If marginal cost pricing is adopted (i.e., charging a customer the additional costs incurred by the utility for serving that customer) a question arises as to what costs may be included. Koger (Ref. 4-17) lists three cost components:

- costs incurred when serving the individual customer,
- costs arising from supplying these individual energy requirements,
- costs associated with being able to supply the individual's maximum power demand,

and notes that individual additions to these costs cannot be measured accurately for all three components. If marginal cost pricing is considered too difficult to enact, another alternative is peak-load (time of day) pricing, whereby users are charged more when power demands are greatest, because higher demand requires more capacity and the use of more expensive peak-load generators. But a time-of-day rate schedule may create new peak demands of its own; there is much uncertainty about energy users' ability to reschedule electricity needs.

Uncertainty also manifests itself in other areas--there are risks associated with fossil fuel prices in the future, new technologies, regulations, political changes, supply questions, investment alternatives, investor reaction, ownership changes, etc. These uncertainties add to the difficulties of supplying energy.

Another impact of the transition will be changes in employment. As methods of energy production become more capital intensive, and more foreign energy is used, there may be a decreasing number of energy-related jobs in the United States.

The other major consideration is environmental. Using lower grades of coal and oil increases emission levels. Nuclear capacity requires water for cooling; refining of fossil fuels also creates water pollution. Tremendous amounts of land are used for coal mining, oil shale development, transmission line throughways, and solar collectors.

These issues have widespread consequences and no simple solutions. The next subsection explores the impacts dispersed solar power systems will have on these issues, and outlines some potential applications of solar thermal power.

B. IMPACTS OF DISPERSED SOLAR POWER SYSTEMS ON MAJOR ISSUES

The previous subsection listed a wide variety of changes predicted for the energy system, and the economic and environmental problems those changes will create. It remains to be seen in which areas solar thermal systems will have potential use, and the advantages and disadvantages thermal systems present in each of those uses.

1. The Areas of Potential Use

Within the overall economy, there are probably four areas where solar thermal systems are of the greatest potential for the 1980-1990 time period.

a. Industry. Firms requiring large amounts of heat, power, etc., could use solar thermal power as a cogeneration technique, where solar is combined with process heat production to augment other energy purchases and reduce overall energy costs. Here, solar may be cheaper than central station electricity or development of synthetic fuels. There is reduced industry exposure to energy curtailments and price increases. Solar also improves the overall efficiency of energy use; cogeneration uses previously wasted process heat. As producers of industrial direct heat, solar furnaces could displace gas and coal fired furnaces to produce fuels, chemicals, and other new materials.

b. Remote. Users outside of present electric grid systems would find transmission costs and high power line installation charges uneconomic, and might prefer usage of solar power combined with storage or hybrid solar plants using fossil fuels as backup.

c. Small Communities. These users are within the electricity grid, but are at its outer fringes. Because of high transmission costs and relatively low land prices, small communities might find solar power very attractive. Another group of potential users would be district heating and power stations; advantages to power stations are the same as industrial cogeneration.

d. Utilities. Solar power would be one more energy resource utilities could rely upon; remote power plants could be used to reduce transmission costs and levelize loads.

An overview of the energy market size and growth is contained in Table 4-1, (Ref. 4-16). The first two columns list 1978 and 1990 energy use by market sector; the indices are derived by multiplying quantities of each fuel consumed by their respective fuel prices. Column three shows predicted growth in each sector; as mentioned previously, electricity usage is the major growth area, but almost all fuel uses are expanding. Solar thermal power could affect six of these ten markets; district heating and power systems affect residential and commercial fuel use (the first, fourth and seventh categories), while cogeneration possibilities affect industry usage (the second, third, and eighth categories). How much of an effect solar thermal power has depends on many little-known variables, but the potential impacts in the four categories listed above are very large.

Table 4-1

Energy Usage Markets (1978-1990)

Price x Quantity Index (1978 Dollars x 10^9)

	1978	1990	Growth, 1978-1990
Residential and Commercial Electricity	51	94	43
Industrial Electricity	20	58	38
Industrial Natural Gas	16	42	26
Residential and Commercial Natural Gas	19	43	24
Coal to Electric Utilities	11	30	19
Petroleum to Electric Utilities	9	23	14
Residential and Commercial Petroleum	16	28	12
Industrial Petroleum	17	26	9
Industrial Coal	3	6	3
Natural Gas to Electric Utilities	5	2	-3

Given the four major users listed above, the advantages and disadvantages of dispersed solar power systems are outlined below; a description of how each of the four user areas is affected is also included.

2. Advantages

a. Modular. Solar energy systems contain many small components and are subject to mass-production techniques; their size also makes them somewhat portable. Although centralization provides economies of scale, mass producibility probably would make the units cheaper and more easily replaceable than components of a centralized power plant. All four types of users, but especially utilities, may take advantage of this modularity. Solar units may be integrated into rural power plants (where land is cheaper) or dispersed to serve major load centers (such as industrial parks and residential developments); also, they can be moved as demands shift to other areas.

b. Flexible. As demand loads change, the number of solar units supplying power for the area may be increased or decreased. This is especially useful for industries, whose production requirements change over time, and for utilities, who can change their capacity as users leave or enter the system; the units may also be used to add intermediate or peak capacity without long-lead construction time. As noted by the Office of Technology Assessment (Ref. 4-23), utilities may be in the best position to optimize positioning of solar units. They can compare marginal costs of developing different energy sources (rather than the average cost, which users of electricity pay utilities, and which is lower than the development cost of new energy resources). Utilities can draw on financial sources to which many other users do not have access. Also, they already have construction and maintenance crews. Alternative arrangements (such as leasing or user ownership) would require major institutional changes and a lengthy period of development.

c. Shorter Lead Times. Construction of individual solar units takes less time than construction of a centralized power plant with similar output. This reduction in building time reduces costs due to interest on the investment and to inflation over time; it also allows rapid adjustment to changing energy demands.

d. Impacts on Environmental Quality. Solar power does not have the same types of air emission problems as coal or traditional fossil fuel power plants; it also does not have the water pollution problems other plants may have. Furthermore, production of synthetic fuels from coal requires large amounts of water; water is a very scarce resource in the Western United States, where coal synfuels and slurry pipelines are projected. Finally, by reducing needs for throughway transmission lines to remote areas and small communities, degradation of land in these areas is also decreased.

e. Fuel Savings. Increased use of solar systems reduces needs for traditional fossil fuel resources; by moderating demand for fossil fuels, there is reduced pressure on prices, the amount of each fossil fuel demanded, and consequently on the leverage foreign countries have over price increases or quantity cutbacks. In addition, fuel suppliers will not have to finance as many investments in new technology, exploration, and development as they would in a base case, or could postpone investment projects until technologies were more fully developed. As supplies and prices of non-renewable resources become more uncertain, this decreases the vulnerablility of all four user types to changes in non-renewable fuel output and prices.

f. Increased Employment. This may or may not be considered an advantage, since it is usually the standard of living rather than the size of the labor force which concerns policy analysts. The Mitre Corporation (Ref. 4-20) found that repowering to solar at a rate of 3000 MW/yr will create 180,000-360,000 new jobs in the U.S. by the turn of the century. Benson (Ref.4-4) cites a forthcoming Council on Economic Priorities (CEP) study, which finds that solar usage increases the number of available jobs in comparison to nuclear power. It also leads to a better distribution of on-site employment; nuclear power plant employment follows a bell curve, meaning that most employment is concentrated into the few middle years of power plant construction. However, solar thermal systems have a more even distribution of employment. This can provide small communities in remote areas with more permanent or better jobs for residents; on the other hand, it can also result in rapid growth and the problems related to such in-migrations of people and firms.

g. Reduced Uncertainty. By installing solar thermal capacity, users reduce their susceptability to fossil fuel price increases, and supply curtailments. Once solar capital is in place, the power output and costs can be predicted with a fair amount of accuracy on an annual basis. This is not true of fossil-fuel power, since the price of fuel inputs rises at an unpredictable rate.

h. Easy Integration. Solar thermal equipment can be manufactured, installed, maintained, financed, and insured by organizations and individuals now performing those services for conventional heating, cooling and industrial equipment.

3. Disadvantages

a. Uncertain Technology. These uncertainties include problems with variability and intensity of insolation, seismic susceptability, legal problems with new inventions, market potential, and the unknown alternative technologies; a study by Southern California Edison Company (Ref. 4-7) gives a thorough listing of these problems for utilities. Also, widespread use of solar power will require more sophisticated weather prediction, and more complex equipment control to take advantage of weather information.

b. Land Use. Collection of solar energy requires a relatively large surface area. Preliminary estimates by Rose (Ref. 4-26) suggest that a 1000 MWe generating station powered by central receiver solar energy requires a collector surface area of over 40 square miles. However, this is comparable to the land area required for strip mining of coal to supply the same size power plant for 25 years, if the coal were in a 20" seam. (Ref. 4-14). Even so, efforts to minimize collector area will also reduce competition for land.

c. Initial Capital Cost. A large number of studies have attempted to estimate the initial cost of constructing solar thermal systems. Studies by Duff (Ref. 4-9), Parrish (Ref. 4-24), Battelle (Ref. 4-2), Oak Ridge National Laboratories (Ref. 4-22), Sandia Labs (Ref. 4-25), and JPL (Ref. 4-16) have attempted to quantify systems cost, suggest optimal least-cost combinations of technologies, set cost targets, and compare solar costs with alternative fuel technologies. These capital cost estimates were discussed briefly in Section III; but initial investment costs will continue to be one of the greatest uncertainties of solar thermal systems until cost estimates based on experimental power plants are available.

d. Reliability. Because solar power systems do not operate when insolation is reduced (at night and on overcast days), backup power must be provided by storage, or by switching to fossil fuels. A study by Bloomfield and Calogeras (Ref. 4-6) has shown that, in certain cases, hybrid power systems (where fossil fuels augment solar capacity) provide capital and energy cost savings relative to solar thermal plants with thermal storage. But existing regulations hamper use of hybrid systems, since no new power plants may use natural gas as a fuel input. In any case, thermal storage, fossil fuels, or electric power backup may increase reliability, but these backup energy sources are costly.

e. Capacity Credit. Since insolation is unreliable, some form of backup energy must be available. Three factors affect the amount of capacity backup needed: first, the amount of backup per kWe of solar depends on the correlation between load and insolation. If utilities must meet all demands for electric energy, then they must have capacity for poor insolation days, when users' solar power (as well as the utilities') may be unavailable. Unless solar insolation is greatest when energy demand is at its peak, this causes duplication of capacity. Secondly, the incremental amount of backup needed increases as each unit of solar energy is added to the grid. As the energy supply sector relies more heavily upon solar energy, the investment in backup energy systems per unit of solar output rises. Finally, the amount of backup needed is highly system specific; much research still needs to be done to minimize backup capacity needs.

f. Pricing Problems. Widespread adoption of solar power could profoundly affect utility demand patterns; the cost-effectiveness of solar power to users will be dependent on the rate structure chosen. A study by Dickson et al (Ref. 4-8) shows that the existing rate structure subsidizes solar users at the expense of other utility customers, but use of Hopkinson tariffs (peak-load pricing for solar-using customers) discriminates against solar power. Koger (Ref. 4-17) suggests that time-of-day pricing might resolve this problem, while Freeman (Ref. 4-11) argues for a rate-base system, like those currently used, if thermal systems can be treated as utility property for rate-making purposes. Another possible pricing system is the interruptible rate schedule, where some users are offered reduced rates to occasionally forgo peak use; this would allow interaction between users and suppliers, and consumers could establish a trade-off between reducing electricity rates and doing without power. The effect of these various pricing schemes is not well understood and will require further investigation.

g. Public Safety. Although little research has been done in this area, there are questions about hazards to the residents of surrounding communities when high temperature solar collectors are placed in the locality. The main issues are a potential increase in fire hazards, and the possibility that nearby solar collectors would represent an "attractive nuisance" to neighborhood residents.

A synthesis of the previous information shows that dispersed solar power systems may have potential benefits for a wide variety of users. As with all technologies, there are also drawbacks; development of solar capability will be a costly and risky venture. But as Anderson (Ref. 4-1) has pointed out, residential energy price elasticities are not very promising; higher fuel prices will require either more conservation or the use of new fuel sources. A large number of problems must be resolved before any new fuel sources are used; these problems are addressed in the next subsection.

C. UNRESOLVED ISSUES

The path toward solar energy usage is full of technological, environmental, social, and economic problems. This subsection explores the economic issues raised by the energy transition, and by the development and use of dispersed solar thermal power. There are many forms of risk and uncertainty in designing, purchasing, and operating solar thermal power systems; there are also a wide variety of market problems facing such a new and complex technology. Each of these factors has a direct impact on solar power's viability in the economy, and will be discussed in later subsections. This analysis is prefaced by a description of the value of solar energy, viewed from an economic standpoint.

1. The Value of Solar Energy

This subsection examines the motives underlying the development of solar power. It is often stated that solar capacity should be developed in the most efficient manner possible; "efficient" usually refers to system performance, and implies that a system with the largest power output per unit collector surface area is the most efficient. But there is also a broader definition; "efficient" implies the achievement of a purpose at the least cost and misallocation of resources. This means that high performance is important, but other factors are also considered, such as initial purchase price, fuel usage, complexity or expense of operation and maintenance, environmental side effects, riskiness, and the burden such a technological development would place on social and regulatory institutions. A solar thermal system may be efficient from a technical standpoint, but if it siphons inordinate amounts of resources from other sectors, or imposes much higher social costs than the alternatives, it is not economically efficient and does not merit the industry and government support given to its alternatives.

This concept of economic efficiency is important because of the scarcity of resources; diverting inputs toward one sector lessens the number of inputs available to other sectors. Increased investment in new energy technologies is made at the expense of other investment projects, and new solar energy projects are economically inefficient when they displace projects with greater social benefits or smaller social costs.

The only relevant costs for decision-making purposes are marginal costs, i.e., those which must be undertaken to obtain an additional unit of output. Fixed costs (contractual commitments for rental, depreciation, overhead, etc.) must be paid regardless of the arrangements made; they have no bearing upon the final decision. However, marginal costs may encompass more than just the purchase price of inputs; they should include estimates of non-monetary costs, such as damages to the environment, increased risks, reduced reliability of production, safety hazards, greater need for legislation, and so on. The resulting estimates of marginal cost can be compared to expected benefits (again including non-pecuniary benefits, such as reduced supply uncertainty, greater flexibility, etc.) to determine the net worth of a project; if marginal benefits outweigh the additional costs, the project merits commercial or government attention. Undertaking investments whose expected marginal costs exceed expected marginal benefits does a disservice to the remaining sectors of the economy, since valuable resources are taken from more advantageous alternative projects.

In addition to determining the social value of a single project, marginal costs may be used to rank alternative techniques for achieving a given purpose. Comparable alternatives may be analyzed, and those with the smallest marginal costs given highest priority; this comparison results in a ranking of projects according to their value to society. Ideally, this estimate of marginal cost would be the best measure of a project's value to society; however, uncertainty and market problems may obscure this measure of social worth, or result in an incorrect ranking of projects. When this happens, social cost and user cost diverge, and individual project rankings differ from those of society as a whole. Individuals invest in projects with smaller societal returns or greater societal costs than alternatives.

The next two subsections outline the factors which create such a cost divergence, and discuss how these factors affect user evaluations of solar energy.

2. Uncertainty

One of the major factors which blurs the value of solar energy to society is uncertainty. The indeterminate nature of future events, present regulations, and potential technological innovations makes a single estimate of a system's marginal cost difficult. Furthermore, uncertainty appears in many stages of the production process; this multiplies the number of potential outcomes. Energy users who might otherwise have invested in solar thermal systems will instead utilize alternative, better understood power sources. Even if the expected returns from a solar thermal system are greater, they could be offset by a higher variability; users might prefer a more certain but lower return to one that on an average is greater, but in actuality may turn out to be much less.

Uncertainty appears in many stages of the development of solar energy. It can be classified into four broad categories of uncertainty:

a. Technological Uncertainty. The development of solar thermal power is an ongoing process; much work must still be done to make solar technologies a viable energy alternative. Basic research is being done to improve collector efficiency and to reduce conversion losses; these research areas are described more fully in Section II. No level of technological innovation can guarantee the competitiveness of solar energy, because even larger technical breakthroughs may take place in alternative power sources. For example, reduction in conversion and transmission losses may improve solar power's efficiency, but it also makes electric energy more attractive; since electricity can be generated from a variety of fuels, improved conversion and transmission efficiencies may actually undercut the competitive capabilities of solar power.

b. Cost Uncertainty. Even if specific energy performance levels are achieved, there is no assurance that solar power costs will be comparable to alternatives. Initial capital costs may be very high, backup power sources may be expensive, and maintenance costs could be quite large. Also, the alternatives may be cheaper to use and install, again undercutting the incentive to install solar thermal capacity.

c. Demand Uncertainty. Solar thermal systems may not be used extensively even if cost competitive, because market demand for solar output may be insufficient to sustain large quantities of solar investment. Business and government planners have attempted to circumvent such demand problems by estimating the market penetration levels solar power might attain when a certain set of capital cost goals are realized. These estimates overlook the numerous uncertainties involved in forecasting market size, relative prices, and the state of technology. Section V makes an extensive survey of market penetration models, and notes the strengths and weaknesses of current analyses. However, estimates of the proportion of demand filled by solar energy await better data on solar power cost and performance.

d. Institutional Uncertainty. Another source of change is the regulatory and social framework into which solar thermal systems will be introduced. Government policies toward solar energy and its alternatives are subjected to continuous reevaluations. Legal issues in the siting of collectors may surface when solar power begins to compete for scarce urban or agricultural land. Building solar thermal systems involves much uncertainty about construction lag times and strikes, future inflation rates, and general economic conditions. Finally, public attitudes toward solar energy may change if safety hazards, maintenance problems, or high capital costs materialize.

Each of these types of uncertainty slows the development of solar energy. Even if a solar power system reaches its cost goals (which disregards uncertainty about performance, construction lag times, inflation rates, and reliability) the system may not be competitive; alternative fuel sources may still be cheaper, other power systems may be more efficient, or market demand for solar output may be insufficient to sustain large scale investment in solar power.

A discussion of policies or methodologies to resolve these issues is included in the final subsection of this chapter. The analysis now turns to an exploration of problems in the market structure which obscure or confuse the value of solar energy to society.

3. Market Problems

Even if all uncertainty about solar technologies, costs, regulations, and market demand levels could be eliminated, there are still a number of economic problems which make evaluation of solar energy difficult. These may be classified as follows:

a. Information Problems. Incomplete information or information biased by financial incentives and special rate structures can cause energy users to install power systems which are not economically efficient. Poor information and special treatment of alternative energy sources can discourage use of solar power as effectively as regulatory disincentives.

b. Capital Market Problems. Solar thermal power systems are very capital intensive, and require a large initial investment. High front end costs are a problem because even though a solar power system has positive net benefits, the potential purchaser may be unable to borrow the full amount of necessary investment at the going rate of interest. Users may therefore install systems with lower initial purchase prices, even though such systems have higher energy costs in subsequent years.

c. Externalities. Usage of some forms of energy results in societal gains (or losses) which the firm is unaware of or unable to reflect in its price. An example of positive benefits is the flood control provided by hydroelectric dams; pollution is the most notable example of external costs. Solar thermal systems will compete for scarce urban and agricultural land; but in comparison to alternatives, solar power causes less air and water quality degradation and reduces energy supply uncertainty. If energy producers cannot reflect the external costs and benefits of a fuel resource in its price, then the energy usage pattern may not be the most socially desirable. Resources with negative externalities (net societal costs) are oversupplied, while inputs resulting in social benefits are undersupplied.

d. Market Biases. Existing regulations and industrial organization may hinder the development of solar power. Special financial incentives (such as depletion allowances, foreign tax credits, etc.) given to alternative energy sources encourage their use. Some utility rate structures subsidize solar power; others penalize it. These subsidies can be defended if firms would otherwise have produced less energy than desired by society, either because of uncertainty, capital market imperfections, monopoly power, or externalities. By encouraging energy production, they reduce the imperfections in market allocation that would otherwise exist, and create a socially preferred output mix. If these subsidies are extended to all energy sources except solar power, this causes a misallocation of energy inputs, i.e., a less than optimal amount of solar energy is used.

Each of these factors tends to obscure the value of solar energy to society, and may even change the choice patterns of users. The next subsection surveys the policy and project options available for dealing with these issues, and suggests possible approaches toward resolving them.

D. A RECOMMENDED AGENDA

Drawing together the analysis of preceding subsections, the most basic trend is that U.S. energy demand will continue to rise, but for a variety of reasons domestic supply will not grow as rapidly. This means that energy prices will increase, and producers may depend more heavily upon foreign reserves. Domestic supplies will be of declining quality, which results in higher costs and environmental side effects. As costs rise, users will begin investing in the alternative energy technologies made feasible by these rising prices; one of these alternatives may be dispersed solar thermal power systems. Solar thermal power will have widespread impacts on energy issues; some will be positive, such as reduced dependence on foreign resources, less pressure on fossil fuel prices, greater supply flexibility, and decreased environmental side effects. A large number of questions concerning the solar power market, and the uncertainty in it, must be resolved before solar thermal systems become widely used.

In the past, through improved technology, improved capital markets, and various subsidies, the development of fossil fuels and nuclear energy has been expedited and accelerated by government programs. It should be realized that these subsidies cause larger amounts of energy use than would otherwise take place; extending these favors to solar power merely aggravates the energy use situation. Subsidies to solar power therefore offset some of the energy conservation purposes for which they are advocated. The best means of saving energy would be to remove subsidies from all forms of power, including solar. Such sweeping changes are difficult, even if desirable; regulations may be impossible to remove, and the beneficial side effects (such as flood control) of some systems may argue for their continuance. If all favors cannot be removed, it may aggravate misallocations to remove only some of them. Thus, solar subsidies may counteract interfuel misallocations, although all energy forms may be used in more than optimal amounts.

The question remains as to which programs would be most efficient (i.e., achieve their purposes at the least cost and misallocation of resources). The proposed strategies fall into two broad categories: those which reduce capital market imperfections, and those which reduce uncertainty.

Solar power is one of the most capital intensive forms of energy production. High front-end costs are a problem because even though a solar thermal system has positive benefits, the potential purchaser is unable to borrow the full amount of necessary investment at the going rate of interest. Therefore, any incentive which reduces high initial system prices helps lessen the imperfect capital market distortions; examples of such incentives include installation tax credits, low interest loans, matching grants, interest tax credits, and outright subsidies.

The second type of incentive attempts to reduce uncertainty. As mentioned previously, solar power may not be used because of information problems, such as a lack of knowledge (or uncertainty) about cost, performance, etc. Incentives which attack these problems include equipment warranties, performance guarantees, R&D programs, quality standards, design contests, and leasing arrangements. While these may indirectly reduce cost (through development of cheaper or more efficient technologies), their main impact is on information gathering and dissemination.

Each form of incentive will affect a different problem and have different impacts on users. The various forms of tax incentives are regressive, meaning that more profitable investments benefit to a greater extent or more rapidly than less profitable ventures. This is because credits must be balanced against a purchaser's tax liabilities, and users with larger tax liabilities (the more profitable firms) can take larger investment write-offs in any given year; thus, a newly purchased solar thermal system will qualify for the full tax credit much more quickly. Loan programs allowing purchasers to borrow the full amount of the investment at a given rate of interest circumvent this regressivity problem; less well-off firms derive the same benefits as prosperous ones, and the market imperfection is attacked directly, by subsidizing the capital loan market. A more complete exposition of this analysis is contained in Berman and Fisher (Ref. 4-5). Uncertainty-reducing programs may not stimulate output as much as capital market incentives, but they reduce the information barriers facing system buyers.

Choice of an incentive (or group of incentives) will depend on which market imperfections are viewed as the major road blocks to an operational, smoothly functioning market for solar energy. It must be realized that a large, complex incentive system can be as much an obstacle to a smoothly operating energy market as the original imperfections. Incentives should be directed toward overcoming existing market problems, and not toward making solar power commercially available before technological and economic groundwork is complete; otherwise, the goal of giving a variety of energy forms equal treatment is lost in a landslide of regulation and windfall gains. Therefore, it might be useful to first use incentives which reduce uncertainty and develop better system designs and cost estimates; these steps alone might create a viable solar power market. If further incentives were judged to be necessary because of capital market problems, subsidies to other forms of energy that could not be removed, or the desirability of reduced environmental side effects, then an integrated set of subsidies could be used.

There are many good reasons for developing solar power capabilities; then again, there are many poor ones for subsidizing it. Subsidies should not be given just because the price of other energy sources is rising; higher prices tend to ration scarce resources, to promote conservation, and to motivate a search for substitutes. Incentives should be used only when a less-than-socially desirable amount of solar energy is produced, because of market defects. Then the choice of incentives will depend on the perceived market problems.

It is therefore necessary to explore the economic issues which will face solar thermal power systems. Research efforts should include studies of uncertainty, regulation, demand, and market defects; this will greatly aid the development of solar power and minimize resource misallocation. It will also reduce the likelihood of implementing subsidies which promote windfall profits rather than economic efficiency.

One possible aid in the reduction of uncertainty and installed capital costs would be a program of R&D assessments of the technical, economic, and institutional progress of the various solar power systems. Currently, solar power costs are uncertain, and will not be known until experimental hardware is in operation and installed costs can be tracked. This suggests that research efforts (whether by government, private industry or academic institutions) should focus on documenting installed costs and developing technological refinements which reduce system costs. This does not imply, or justify, large scale demonstrations, mass production, subsidies, government purchases, or other such major involvement; these detract from the main effort, which is to reduce costs and cost uncertainty. Such an R&D program would produce and monitor technical and economic progress, and use this progress to further optimize solar power techniques and to tailor new developments to specialized markets.

In addition to development of solar hardware, another important area of research is the market situation facing solar technology; no level of technological development or cost reduction will guarantee a system's competitive potential. Listed below are some of the major topics of concern and associated questions.

1. Uncertainty

   - Which uncertainties present the biggest obstacles to solar power usage?
   - What is the most efficient way to resolve these uncertainties?
   - When is the optimal time to commercialize a new solar technology?
   - How can variability in system factors (price, reliability, etc.) be expressed so as to reflect uncertainty?

2. Overall Economy

   - How do additions of solar power capacity effect overall employment and employment patterns?
   - Which regions will feel the impact of solar usage most?
   - How will this difference in regional impact be manifested?
   - Solar power is among the most capital intensive forms of energy; how will large demands for capital (especially if accelerated by solar incentives) affect interest rates, real estate prices, housing markets, and other forms of investment?

3. Regulation

   - What costs do energy regulations impose on society?
   - Are the benefits of these regulations worth the cost?
   - Should regulators base decisions on average costs or marginal costs?
   - What alternative fuel usage scenarios will solar energy choices be based on?

- No new power plants may use natural gas; but hybrid (solar and fossil fuel) systems may be the most efficient usage of solar power. How does this regulation affect solar hybrids, and the energy users choice set? How costly is this ban on natural gas usage?

- What criteria will be used to resolve siting issues?

- What criteria will be used to resolve insolation rights?

4. Pricing Structure

- How do utilities determine their rate base?

- Which energy pricing method (peak load, etc.) is most efficient?

- Which energy pricing method is least costly to administer?

- Utilities currently pass increased cost of operation directly on to consumers. Is supply elastic enough, and demand rigid enough, to justify this? If not, what changes might be made?

- Currently, utilities must have enough capacity to supply maximum levels of demand. What pricing mechanisms might allow demand and supply to interact?

5. Financial Incentives

- How big are the market imperfections these incentives are designed to overcome?

- How does each incentive affect solar thermal costs?

- How does each incentive affect solar thermal usage?

- Which sectors of the economy benefit most from any given incentive?

6. Ownership

- Will ownership of a solar thermal system for cogeneration purposes subject a firm to the same kinds of regulation faced by utilities?

- How do the impacts of financial incentives vary by form of ownership?

- Which incentives work best for each type of ownership?

- How much does category of ownership affect the cost of solar power usage?

A better understanding of these topics will aid in the development of solar energy. As technological innovations improve the viability of solar power from the supply side, so a better grasp of economic issues may promote the competitive ability of solar power from the demand side.

Overall, this section has produced many more questions than conclusions. At this stage of solar power development, however, a careful look at these questions may be the most constructive thing which can be done for dispersed solar thermal systems.

SECTION V

FINANCIAL ANALYSIS OF SOLAR THERMAL POWER PLANTS

A. RATIONALE FOR A FINANCIAL ANALYSIS MODEL

A meaningful evaluation of the potential impact of solar thermal power plants in the energy marketplace of the future must include a detailed study of the costs of such plants relative to the cost of conventional power plants or of other advanced technology power plants such as wind, photovoltaic, biphase diesels, etc. Although many diverse and subjective factors enter into the decision-making process concerning capital investment in a power generation technology, the element of cost is a critical factor in that process. Yet an analysis of the cost of any type of power plant is very complex. It involves much more than simply determining the price tag, the first cost, of the plant. It involves looking at the cost of not only buying, but also of operating and maintaining the plant, the life-cycle cost.* Second, it involves determining how those life cycle costs are affected by the financial context of the owner(s) of the plant. A variety of ownership alternatives are possible: private utilities, public utilities, industrial companies, commercial companies, cogeneration joint ventures between utilities and industry, third party owners (who lease plant equipment), etc. The operational mode of a power system and the applicable financing opportunities, requirements, and incentives will differ for each of these ownership alternatives, causing the life-cycle costs to vary correspondingly. Third, the cost of a plant varies with the design and the construction time of the plant and with the distribution of costs over the construction period.

In order to determine how all of these factors define, in a standardized manner, the cost of investment in various power technologies to a variety of owners, a model is required which has the flexibility to accurately represent the appropriate financial context for a variety of ownership alternatives. In addition, it must provide financial statements consistent with accepted business accounting practices and financial systems. Such a model has three major uses:

(1) As a research tool for policy analysis, the model can be used to identify those ownership arrangements, financing provisions and tax incentives which cause the perceived cost of solar thermal technology to be competitive with conventional technologies or other

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*Life-cycle costing is a method of expenditure evaluation which recognizes the sum total of all costs (appropriately discounted to standardize costs from different time periods) associated with the system during the time it is in use. It is an evaluation technique, an input for decision making. Life cycle cost analysis considers, in addition to initial capital investment costs, such things as annual operating and routine maintenance costs, the costs associated with major repairs, component replacements, subsystem replacements, and residual values.

advanced technologies. This information is essential to the planning for the acceleration of the commercialization of this technology.

(2) As a tool for R&D engineers, the model can be used to identify the areas for solar thermal technology development which would be expected to ultimately result in system designs having maximum commercialization capability in the largest number of utility, industry and commercial applications.

(3) As a decision-maker's tool, the model enables buyers in the power system marketplace to implement a life-cycle cost perspective (a viewpoint critically important in times of rapid changes over time in energy costs), to perform trade-off studies between capital and operations and maintenance costs, and to be able to identify in a standardized way the costs of different power system technologies having varying capital intensity. The model's consistency with commonly used accounting and financial systems in private industry assists in insuring its acceptance by potential buyers in the power system marketplace.

In this section, the factors which have a potential effect on the economic feasibility of power systems, and hence on the decision-making process, will be detailed. The analytic methodology utilized in the model and the inputs required by that methodology will be described. The variety of analysis options will be identified. The various ways in which the results can be couched will be specified and evaluated as to the worth and proper interpretation of the information contained therein. The methodology will be compared to other methods of capital investment analysis as to applicability and usefulness. Validation methods will be discussed. The required economic, financial, and technical data base will be specified and the inherent assumptions in the generation and interpretation of the various output options will be discussed and justified. The results of applying the model in a variety of case studies will be shown. Suggested research areas for future expansion of the model will be detailed. Finally, the manner in which the model can be used to develop successful strategies for the achievement of economic feasibility of solar thermal small power systems will be discussed.

This work is being supported via an external contractor, ESC Energy Corporation. The final report for that contract was published February 5, 1979 (Ref. 5-1).

B. THE FINANCIAL ANALYSIS OF POWER SYSTEMS

The life-cycle costs of an investment decision in favor of any particular power plant depends on the performance and cost of that power plant, on the financial environment of the decision-maker/owner, and on the economic assumptions made regarding the general economy and the specific owner.

System performance assumptions cover plant size, capacity factor, heat rate, efficiencies, reliability, insolation, effective load-carrying capability, etc. System cost assumptions include cost per kWe of purchased capacity, at both the system and subsystem levels, and the expected change in these costs over time due to technological advances (both engineering and mass-production related) or escalation of raw material costs. System operating assumptions include fuel cost, plant insurance rates, fixed and variable O&M costs, inventory costs, working capital requirements, etc. Economic assumptions involve inflation rates, price deflators, escalation rates on the costs of capital goods, energy prices, and rates for backup power, resource depletion rates, energy and fuel supply demand by source and sector. Financial assumptions which must be considered are owner-type specific and include debt/equity ratios, interest and dividend rates, financing costs, methods for amortization of financing costs, bond retirement, income and other tax rates, investment tax credits, tax exposure, book value and depreciation schedules, construction schedules and fund drawdown schedules, installation costs, etc.

It should be noted that variations in financial assumptions do not alter the true cost of an investment decision to society, only to a particular investor/owner. For example, the cost perceived by an owner might be less because another segment of society (e.g., the government) is paying a portion of the cost (e.g., tax credits decrease the cost to the owner, that cost decrease being paid for by the government who collects, as a result, fewer tax dollars and hence must borrow additional monies).

1. The Basis for Solar Thermal Economic Analysis Methodology--Yearly Cash Flow Analysis

The Solar Thermal Economic Analysis Methodology (STEAM) is based on the principles of life-cycle analysis. It requires the calculation of the cash flows associated with an investment for each year in the investment project time horizon. This involves specifying for each year: revenues, investment costs, operating expenses,* return on equity provisions, depreciation provisions, repayment of debt capital, applicable tax credits and tax deductions, and tax rates.

Operationally, the methodology evaluates alternative investment choices by determining the cash flows associated with each alternative (utilizing the above information). It then calculates the difference in those cash flows for each year of the investment project time horizon, producing a series of annual differential cash flows. This process is illustrated in Figure 5-1. Finally, the method calculates a variety of "figures of merit", which specify the relative cost of the alternatives or the absolute life-cycle cost of each alternative. The functional flow chart for the model is shown in Figure 5-2.

The method always assumes that one alternative involves a capital investment in some type of power system by a firm, and that the other alternative is the purchase of power from a utility with no capital

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*Operating expenses include: Fixed and variable O&M, standby charges, demand charges, capacity charges, energy charges, fuel costs, insurance, other taxes and interest on debt capital.

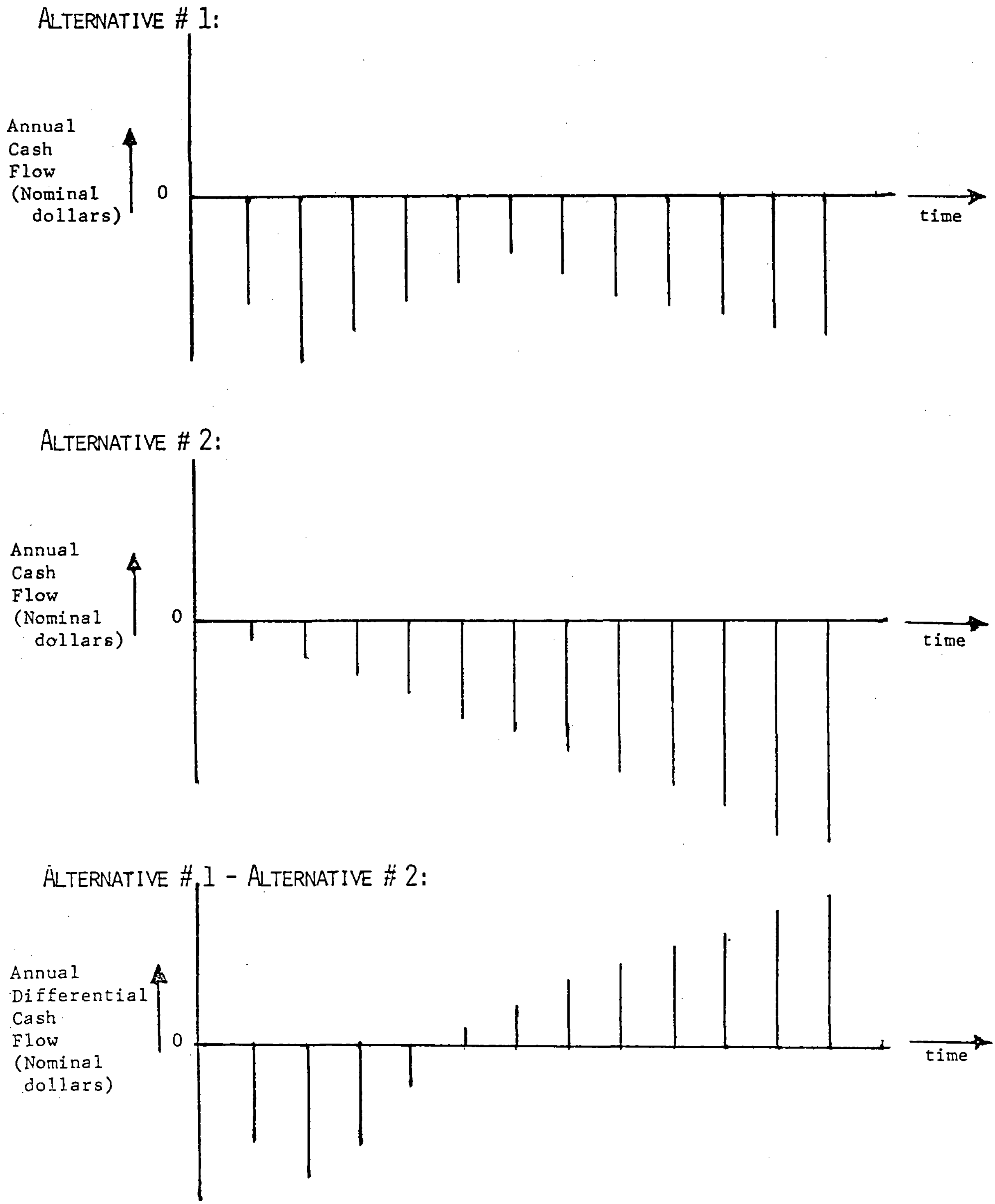

Figure 5-1. Graphic Illustration of Differential Cash Flows

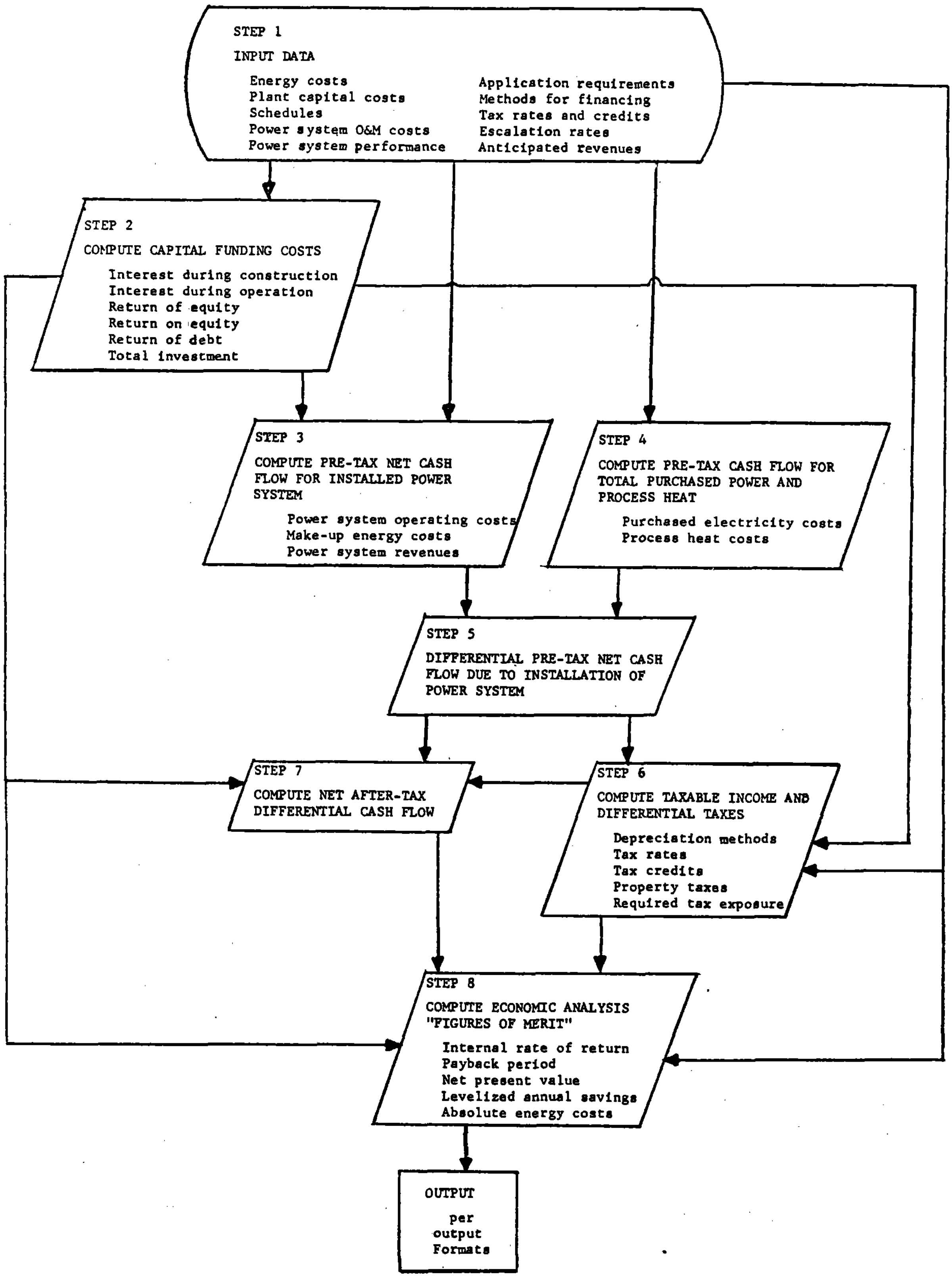

Figure 5-2. Flow Diagram for STEAM

expenditures by the firm. Hence, to compare two alternatives, both of which involve investment in a power system (e.g. a diesel versus a solar thermal power system), each is compared to the common alternative of purchased power. Transitivity of results then enables the two investment alternatives to be compared.

For example, suppose a business wishes to decide whether it should satisfy its power needs by (1) investing in a power generation system or (2) purchasing power from the local utility, making no capital investment. Define the following for any arbitrary year in the project time horizon:

	Alternative #1	Alternative #2
Plant revenues	R	R
Revenues from power system	R1	0
Operating expenses	E1	E2
Down payment on capital investment	I1	0
Depreciation	D1	0
Investment tax credit	ITC1	0
Effective tax rate	t	t
Return on and of equity (common & preferred stock)	ER1	0
Return of debt	P1	0
Property taxes	PT1	0

Then:

A. Cash flow before taxes for alternative #1
$= CF1 = A$
$= R + R1 - E1 - I1 - ER1 - P1$

B. Cash flow before taxes for alternative #2
$= CF2 = B$
$= R - E2$

C. Pretax differential cash flow
$= PDCF = CF1 - CF2 = A - B = C$
$= R + R1 - E1 - I1 - ER1 - P1 - (R - E2)$

D. Depreciation
$= D1 = D$

E. Property Taxes
$= PT1 = E$

F. Taxable income from alternative #1
$= F = R + R1 - E1 - D1 - PT1$

G. Taxable Income for alternative #2
$= G = R - E2$

H. Differential taxable income
$= H = F - G$
$= R1 - E1 - D1 - PT1 + E2$

I. Differential income taxes, before adjustments for tax credits
= t (H) = I
= t (R1 - E1 - D1 - PT1 + E2)

J. Tax credits
= J = ITC1

K. Differential taxes payable, after adjustment for tax credits
= I - J = K

L. After tax differential cash flow*
= pretax differential cash flow - income taxes payable
- property taxes
= C - K - E = L = NCF,AT

When L is greater than zero, the cost of alternative #1 is less than that of alternative #2. This analysis assumes,** in calculating taxes and tax credits, that:

R + R1 is always greater than or equal to E1 + D1 + PT1
R is always greater than or equal to E2
R is sufficient so that 25,000 + 1/2(R + R1 - E1 - D1 - PT1 - 25,000) is greater than or equal to ITC1 for the first year of commercial operation.

If these assumptions are not valid, then the model utilizes tax exposure information as input in order to calculate the realizable fraction of tax deductions and credits.

These after tax, net cash flows (NCF,AT) are determined for each year in the project horizon.

*Note that this method for computing differential cash flows is consistent with the methodology typically utilized for determining cash flows and here shown:

Revenue	= total income (or total savings).
Net Profits	= revenue - all expenses - income tax.
All expenses	= cash expenses + depreciation.
Income tax	= (revenue - all expenses)(tax rate).
Cash Flow	= net profits + depreciation
After Tax Cash Flow	= (revenue)(1 - tax rate) - (cash expenses)(1 - tax rate) + (depreciation) (tax rate).
After tax Cash Flow	= (revenue)(1 - tax rate) - (all expenses)(1 - tax rate) + depreciation.

(Taken from Plant Design and Economics for Chemical Engineers, M. S. Peters and K. D. Timmerhaus, Second Edition, 1968. McGraw-Hill.)

**See Section B.5(b) for specification of how model functions when these assumptions are not valid.

2. Inputs--Financial Analysis Data Base

Table 5-1 lists the input variables which the user must supply for operation of the model. The appropriate values to assign to these variables are of course dependent on the specifics of the case being analyzed. However, generic cases can be defined (e.g., those involving public utilities, those involving industrial owners, etc.) and ranges of values of input variables which are appropriate for each of those generic cases can be developed.

Table 5-1. Financial Analysis Data Base

OWNER-SPECIFIC

- Owner type: public utility, private utility, industry, third party lease, etc.
- Capitalization structure: Ratios of debt, preferred and common stock to total capitalization
- Book value of common stock
- Current market price of common stock
- Current rate of annual increase in market price/share
- Book yield
- Payout ratio for dividends
- Types and costs of financing utilized: bonds, stock, retained earnings, depreciation, mortgage-type loan, simple interest loan, etc.
- Method of depreciation
- Book depreciation schedule
- Tax depreciation schedule
- Interest rates on debt (bonds, loans, etc.)
- Dividend yield on common stock
- Inflation rate
- Escalation rates for: capital goods, purchased power, operations, maintenance, fuel, and special revenues
- Percentage of capital costs depreciable
- Federal and state income tax rates and tax credits

APPLICATION-SPECIFIC

- Total annual electric/thermal energy requirement
- Capacity requirement
- Capacity factor
- Load profile
- Construction schedule
- Subsystem replacement schedule
- Fund drawdown schedule
- Special revenues
- Type(s) and costs of alternative power sources available for application
- System performance

3. Analysis Options

A primary purpose of the model is to enable the user to determine the quantitative effects of variations in the design, ownership, construction, operation, financing and taxation of a variety of small power systems. This type of information is very valuable in evaluating the potential effects of national and state legislation, regulations and policy on the economic viability of small solar power systems in a variety of potential markets. Hence the program contains a number of options with respect to each of these considerations. Table 5-2 lists these options.

Table 5-2. Small Solar Power Systems Program Options

SMALL POWER SYSTEM

- Generate electricity
- Generate electricity with waste heat recovery
- Generate process steam

Ownership

- Public or private utility
- Industrial or commercial

Operation

- Meet all the plant energy needs
- Buy make-up energy
- Sell excess energy

Financing

- Constant payment term loan
- Simple interest loan
- Construction loan
- Bonds
- Equity

Annual Costs

- Subsystem replacements
- Construction expenditure schedule
- Escalation rates

Taxes

- Method of depreciation
- Depreciation period
- Salvage value
- Federal and state tax rates
- Investment tax credit

4. Outputs: Aggregate "Figures of Merit" for Evaluation of Yearly Cash Flow Information

a. The Differential Internal Rate of Return (IROR). One method for quantifying the advantage/disadvantage of one alternative over another from a knowledge of yearly differential cash flows is to calculate the differential internal rate of return, r, using the equation:

$$0 = \sum_{i=1}^{N} \frac{(NCF,AT)_i}{(1 + r)^i} \qquad (1)$$

where N = project lifetime.

This calculation determines that "r" for which the net present value of the differential cash flows equals zero; "r" can provide an indication of the relative efficiency of one alternative over another in its use of capital, provided care is taken in its interpretation. The internal rate of return cannot be blindly used to rank various alternatives. Consideration must be given to the amount of capital investment generating a given internal rate of return and to the opportunity cost of capital. For example, suppose alternative A yields an IROR of 25% on an investment of $1.00 and alternative B yields an internal rate of return of 20% on an investment of $2.00 and that the cost of money is 10%. Which alternative is better? It is not necessarily the alternative with the greater IROR. In this example, alternative A produces a profit of ($1.00)(1.25) - ($1.00)(1.10) = $0.15 whereas alternative B produces a profit of ($2.00)(1.20) - ($2.00)(1.10) = $0.20. Thus, alternative B is the logical choice in this example. If the cost of capital were 20%, then alternative A is the preferred choice.

Alternative	Initial Investment	Cost of Capital	Cost of Investment One Year Later	IROR	Return One Year Later	Profit
A	$1.00	10%	$1.10	25%	$1.25	$0.15
B	2.00	10%	2.20	20%	2.40	0.20
A	$1.00	20%	$1.20	25%	$1.25	$0.05
B	2.00	20%	2.40	20%	2.40	0

Finally, there is an inherent assumption and a major difficulty associated with the use of this method. The inherent assumption is that all differential cash flows generated by the choice of one investment alternative over another are reinvested for the rest of the project's economic life at the same internal rate, an unrealistic assumption if that rate is much higher than the average or typical rate realized by the company in its investment area. The major difficulty is that when the differential cash flows are negative initially and cross the return axis more than once, there exists the potential for multiple roots to exist, making an unambiguous evaluation of the investment alternatives impossible.

b. Net Present Value (NPV). The net present value of the differential yearly cash flows (in the year of construction start-up, y_c, expressed in y_b dollars) is calculated using the equation:

$$NPV = \sum_{y_t=y_{co}}^{y_s+T_E-1} \frac{(NCF,AT)_{y_t}}{(1+R)^{y_t-y_c+1}} \quad (1+g)^{-(y_c-y_b)} \qquad (2)$$

where R = appropriate discount rate (See Section C.1)

T_E = system lifetime

y_t = the year of the cash flow

g = inflation rate

y_c = the initial year of construction

y_s = the year of first commercial operation

(NCF,AT_i) = the differential cash flows after taxes associated with the choice of investment alternative #1 over alternative #2 for year, y_t

y_b = base year for constant dollars.

If NPV is greater than zero, then alternative #1 is preferred to alternative #2.

c. Levelized Annual Savings. (LAS) To compare non-uniform series of money disbursements where money has a time value, it is necessary to standardize them. One way of doing this is by reducing each to an equivalent series of annual uniform payments. This is readily done by multiplying the present value of a project by the capital recovery factor (CRF), where

$$CRF = \frac{R\ (1+R)^N}{(1+R)^N - 1} = \frac{R}{(1+R)^N - 1} + R \qquad (3)$$

where N = project lifetime = $y_s - y_c + T_E$ and R = appropriate rate (See Section C.1)

This calculation gives the uniform, end-of-year cash flows which will result in the total "present worth" cost of the uniform annual cash flows being equal to the present worth of the actual cash flows at a given investment interest rate.

In the solar thermal economic analysis methodology, the net present value calculated according to equation (2) above represents the present value of the total savings realized by investment in alternative #1 rather than in alternative #2. The levelized annual savings (LAS) calculated according to equation (4) below represents the equivalent, uniform, annual savings which an investor realizes per year by investing in alternative #1 rather than in alternative #2.

$$LAS = (NPV)\ (CRF) \tag{4}$$

These savings will be: (a) expressed in current dollars if R used in the CRF factor is the nominal discount rate; (b) expressed in constant, y_c dollars if the inflation adjusted discount rate, $R' = (1 + R)(1 + i) - 1$, is used in the CRF factor.

d. Levelized Annual Savings Per Energy Unit (LCE). Division of the Levelized Annual Savings (equation (4)) by the amount of energy produced per year because of that investment provides a measure of the average annual uniform savings realized per unit of energy (e.g., $/kWhr).

$$LCE = LAS/\text{amount of energy produced} \tag{5}$$

e. Absolute Energy Costs. Calculation of the LCE enables the levelized, annual, absolute (as opposed to differential) cost of any power system alternative to be determined. This is because the levelized annual absolute cost of alternative #2, purchased power, is readily calculated, given the current cost of purchased power and the escalation rate for that cost. Knowledge of the levelized, annual savings per energy unit for alternative #1 over alternative #2 (e.g., 5 mills/kWhr) coupled with the calculated levelized, annual cost of purchased power (e.g. 75 mills/kWhr) enables the absolute, levelized, annual cost of alternative #1 to be determined (e.g., absolute, levelized cost alternative #1 = 75 - 5 = 70 mills/kWhr).

These absolute costs are not absolute in the sense that any and all firms would arrive at the same value. These costs will vary with the discount rate used to calculate the Net Present Value, and that discount rate will differ for different firms, depending on the financial context of the firm and the risk which a given firm assigns to the various investment alternatives. (See Section D.3 for a more complete exposition)

5. Comparison With USES--The Required Revenue Methodology for DOE/EPRI Evaluations:

A life cycle cost model has been developed by J. W. Doane, et al, (Ref. 5-2), and is hereafter referred to as "USES". This model was intended to provide a standard, consistent means for doing comparative economic analyses of various energy systems, particularly solar electric systems. The model is appropriate only for private or municipal utilities. The preface states:

> This methodology addresses only those costs that are incurred as direct results of purchasing, installing, and operating an energy system, and derives the energy "price" necessary to recover those costs. A utility adoption decision will require information additional to that provided by this method; however, the model presented will fulfill the important

function of providing reliable information regarding the relative ranking of energy system options in a consistent manner. All on-going and future studies by ERDA (Energy Research and Development Administration, now the Department of Energy) and EPRI solar energy system contractors will use the method; other energy system analysts are encouraged to do so as well. ERDA is also planning to develop and release a companion model covering user-owned systems.

It is hoped that STEAM will fulfill the above-referenced need for a model to cover user-owned systems. However, STEAM is intended to be general enough to be able to deal with all ownership alternatives: the public/private utility ownership option as well as the industrial or third party ownership options. Hence, one very important aspect of its development and validation process is that STEAM be structured so that, given the proper inputs, it produces ranking results which are consistent with those produced using the appropriate input values in the USES methodology. At the same time, the objective is to expand the capabilities which USES possesses for dealing with municipal and private ownership options.

Application of both USES and STEAM to a common private utility case study indicates that the two methodologies do indeed produce identical results for a common set of inputs and assumptions.

In addition, STEAM provides additional valuable information and relaxes certain critical assumptions and requirements inherent in the USES methodology. These advantages are best exemplified in:

a. Yearly Cash Flows. USES calculates the annualized* revenue required to capture all costs associated with investment in any energy system. This aggregation process causes a loss of specificity--the model does not predict actual year-to-year cash flows. Yet, such information could be critical to a decision-maker. An on-going business needs to have sufficient liquidity for day-to-day operations; projections of yearly cash flows are required for meaningful financial planning. The starting point of the STEAM is the projection of actual yearly cash flows.

b. Explicit Tax Exposure Assumptions. USES assumes all tax deductions or credits can be realized by the firm. This assumes that the firm has sufficient tax exposure and/or tax liability each year against which deductions and credits may be charged. For example, suppose that a corporation's 1977 tax liability is $40,000, and its qualified investment (for an investment tax credit) is $500,000 in 1977, and that the investment tax credit is 10%. The applicable investment tax credit is then (10%) ($500,000) or $50,000. But, in view of the corportion's tax liability of $40,000, the amount of tax credit which can be taken by that corporation is limited to

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*Annualization is the process whereby the total revenue requirements for the system over the entire lifetime of the system are converted into an annuity (a constant annual payment) over the system lifetime, with an equivalent dollar worth.

$32,500.* STEAM deals with tax exposure and applicable tax deductions credits by (a) calculating the tax exposures required to take full advantage of all applicable tax deductions or credits on a year-to-year basis and (b) making anticipated yearly tax exposures or liabilities optional inputs to the program. This allows the program to calculate the fraction of available tax credits or deductions which can indeed be taken and adjusts the cash flows accordingly. At the present time, there is no provision for handling the carry back or carry forward option for investment tax credits. This is a planned future refinement of the model.

c. Sources of Capital. USES assumes that the capital needed for a project is obtained only by bond and stock sales. No provision is made for the use of retained earnings or other sources of capital for financing capital requirements. STEAM offers greater flexibility in utilizing various financial instruments to provide necessary capital.

d. Generalized Treatment of Revenue Requirements During Construction. One aspect of the USES methodology which makes it utility-specific is that it assumes that the costs of interest and return on equity during construction are rolled into the total depreciable capital investment. Yet this procedure is allowed only for utilities and hence the use of the USES methodology for industrial owners is inappropriate.

6. Model Validation Process

Validation of the model is in process. Two external organizations, the Bonneville Power Administration and the California Public Utilities Commission have expressed an interest and a willingness in participating in model evaluation and validation. Their interest derives from their desire to better understand the aspects of advanced energy technology, particularly those amenable to cogeneration. The California Public Utilities Commission views the model as a tool to evaluate the impact of various energy sell-back rates on the feasibility of cogeneration, so that it can structure its regulatory posture accordingly.

C. FINANCIAL ANALYSIS VARIABLES AND ASSUMPTIONS

1. The Discount Rate for the Present Value Analysis

The appropriate discount rate for the present value and capital recovery factor calculations (equations (2) & (3)) is the opportunity cost of investment, the "opportunity cost of postponed receipts of money" (Ref. 5-3). The opportunity cost of investment is the best value for this discount rate because this discount rate serves two purposes:

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*Article 1179 of the 1979 Tax Guide (Commerce Clearing House) states: "The investment credit may not exceed tax liability. If tax liability exceeds $25,000, the tax credit may not exceed $25,000 plus 50% of the tax liability over that amount." At the same time, it should be noted that there are provisions in the tax code for carry back and forward of unused tax credits.

(1) to discount yearly cash flows to obtain their net present value--funds which are invested in the project will no longer be able to make the opportunity cost of investment elsewhere; hence, they should be factored in at the firm's opportunity cost of investment.

(2) to represent the rate at which funds from an investment are reinvested to obtain the project's terminal value--funds which are derived from the project can be used elsewhere and would be expected to return the opportunity cost of investment (the highest alternative return that could have been obtained), had the funds not been committed to that project.

A determination of a firm's opportunity cost of investment requires specific information concerning that firm's marginal investment return. If such information is unavailable, one can use the firm's cost of capital as a reasonable surrogate. To do so implicitly assumes an unlimited capital budget and a perfect capital market. James C.T. Mao (Ref. 5-4) states:

> In a perfect capital market, the net present value of an investment would be computed by discounting the project's net cash flows at the cost of capital to the firm...The normal capital market, however, is not perfect, and firms typically operate under conditions of capital rationing. When a firm's capital budget is fixed, the principle of opportunity cost requires that the net present value of an investment be computed by discounting net cash flows at the firm's marginal investment return.

Any conclusions reached using the firm's cost of capital as the discount rate in the present value calculations should be properly qualified in light of the assumptions inherent in such use.

The next section presents a methodology for determining the cost of capital for a firm.

2. Defining the Corporate Cost of Capital

a. Individual Sources. The normal approach to the calculation of a corporate cost of capital is to make estimates of the separate costs of the various primary sources from which the business may be expected to draw its funds in the future, and then to bring these together in the form of a composite cost with each source weighted in some manner.

The principal types of cash costs associated with the acquisition of funds through financial contracts may be classified as follows:

(1) Periodic payments to the contract holder in the form of interest, dividends, or rent.

(2) Any payment to the distributor of the stock or debt issue as compensation for his services in marketing the issue and for assuming the risks associated with a public offering. The distributor deducts from the price received from investors an amount that he has agreed is adequate compensation and then remits the net proceeds to the

company. The difference between the price to investors and the price to the company is referred to as the "spread".

(3) Other costs incidental to the making of the contract which are paid by the issuing company, such as legal and printing costs.

(4) Any payment to the contract holder at the retirement of an issue in excess of the amount orginally provided by the investor. This discount applies only to securities that have a definite maturity, or which may be redeemed at the option of the company, and only when the issue is sold at a price less than the amount payable at retirement. This amount may be amortized over the life of the issue and considered as an addition to the periodic interest or dividend cost. Through similar reasoning, a security sold at a "premium" would involve a downward adjustment of the interest or dividend cost.

b. The Cost of Debt Capital. This is defined as the interest rate on outstanding debt. In the case of bonds, the measurement of the annual cash obligation takes as its point of departure the fact that bonds must be repaid at a specific future date and that the amount originally received by the company is likely to differ from the amount repaid to the investor at maturity. Thus, for example, if we are considering a 15-year, 8% bond with a face value of $1,000, which brought the issuer $980 net, we must take into account not only the $80 annual interest payment but also the $20 that must be paid to the investor at the end of 15 years in addition to the $980 actually received and used by the company. Use of bond value tables (specifying bond length, nominal % yield, and net yield to investor) enables the actual yield to maturity to be deduced. The section of a bond value table applicable to the problem at hand is reproduced in Table 5-3. For an 8% 15-year bond which nets the company $98 per $100 bond, the actual cost lies between 8-1/8% and 8-1/4%.

Table 5-3

Section of Bond Value Table Relating to 8% Bonds

Yield to Maturity	14 Years	15 Years	16 Years
7-5/8%	103.19	103.32	103.43
7-3/4	102.11	102.19	102.27
7-7/8	101.05	101.09	101.13
8	100.00	100.00	100.00
8-1/8	98.97	98.93	98.89
8-1/4	97.95	97.87	97.80
8-3/8	96.94	96.83	96.73

An alternative method of handling the cost of bonded debt is to price sinking fund purchases and ultimate maturity so as not to incur further costs or to create further income. The cash costs for a bond issue might be as follows:

	Total Amount	$75 Million
(1)	Coupon rate	9.25%
	Price to public	100.000%
(2)	Spread	0.875%
	Proceeds to company	99.125%
(3)	Other costs of issue	$100,000*
	Other costs as % of total issue	0.133%
	Net proceeds to company	98.992%
(4)	Discount	1.008%
	Maturity value	100.000%

*Assumed

c. The Cost of Preferred Stock. For many companies the two basic contractual forms under which external funds are raised are debt and common stock. However, some companies make use of preferred stock contracts from time to time. The assumption that it will be a straight (nonconvertible) preferred stock will avoid undesirable complexity. Suppose that a review of recent preferred issues from a firm shows that preferred stock with a dividend rate around 9% sold at or near par. This then becomes the starting point for costing a possible new issue:

	Amount	100,000 shares per $100
(1)	Cumulative dividend	9.00%
	Price to the public	$100.00
(2)	Underwriter's spread	$1.50
	Proceeds to company (from underwriter)	$98.50
(3)	Other costs of issue to company	$80,000.00*
	Other costs as % of total issue	0.80%
	Net proceeds to company	$97.70

*Assumed for sake of example

It can be seen that although the public would pay $100 per share if the firm were to issue a 9% preferred stock at this time, the company would net only $97.70. Thus the effective cost to the company for money obtained by this contractual form is:

$$\frac{\$9.00}{\$100 - (1.50 + .80)} = 9.21\%$$

This cost is paid out in dividends, which are, of course, "after-tax" dollars and are to be compared with the interest costs of debt on a comparable after-tax basis.

d. The Cost of Common Equity. It is the calculation of the cost of funds raised through common equity issues which is the stumbling block to an efficient and operational calculation of cost of capital. It is quite feasible to conceptualize how this cost should be measured--though there are substantial disagreements on approach--but it is another matter to translate this into a precise number for the individual firm.

The problem lies in the fact that the common stock, unlike the bond and the preferred stock, has neither a floor nor a ceiling on the benefit received by the stockholder. The benefit derived is a residual value subject to considerable uncertainty. There is no guarantee or promise of anything except to treat all shareholders of a given class equally. Thus, "cost" as it relates to common stock, defined in the sense of what the business must do in order to attract new equity investment, is a matter of stockholder expectations with respect to the benefit they hope to derive. To shift the analysis from contractual commitments to market expectations introduces a whole new element of complexity and vagueness into the analysis.

Since the common shareholders are the residual beneficiaries, one can argue that the expected benefits are the earnings after taxes available to the common shareholder, whether paid or not. These earnings can be expressed as a ratio of earnings to current market price (E/P), the so-called "earnings yield." Some companies think of cost of common equity in these terms. Others will argue that the only real benefit derived by the shareholder is dividends, and therefore it is the dividend yield which measures the cost.

However, a moment's reflection in the light of the market price trends of recent years shows the error of thinking of common equity cost in these oversimplified terms. With price-earnings ratios of successful, rapidly growing companies ranging up to 50 times earnings, earnings and dividend yields have been as low as 1% and 2%. It is clear that a cost of equity capital defined in these terms would be a totally unacceptable standard for new investment and completely contradictory to the actual performance of these companies.

A more meaningful line of reasoning recognizes the two basic forms in which the common shareholder receives his benefit. One of these is the dividend income received, and the other is capital gains realized on sale of the security, and accounts must be made of both expectations. The elements of the calculation are: (i) the current market price of the stock, (ii) an expected stream of dividend payment, (iii) an expected terminal value for the stock, hopefully higher than the current market price, and (iv) a discount rate that equates the future benefits to the current market price. Given (i), (ii), and (iii), (iv) can be calculated, and this discount rate is the cost of equity capital--the expected return that justifies investment at the current market price.

Defining dividends received in period t by DIV (t), this relationship can be expressed numerically as follows:

$$\text{Price} = \frac{\text{DIV (1)}}{(1 + R)} + \frac{\text{DIV (2)}}{(1 + R)^2} + \frac{\text{DIV (3)}}{(1 + R)^3} + \ldots + \frac{\text{DIV (N)}}{(1 + R)^N} + \frac{\text{Price (N)}}{(1 + R)^N} \qquad (6)$$

In this equation, R, the discount rate, is the shareholders' opportunity rate of return, derived from expected returns on investments of comparable risk. In addition to this rate, the assumptions that must be worked out are the assumed growth rate in dividends and the factor or factors determining the terminal value in year N.

On the question of what determines future market values, volumes have been written and no clear consensus reached. One can, of course, make some crude assumptions. One can agree, for example, that the dominant consideration in market value is the expected growth rate in earnings per share (EPS). Given the expected growth rate in EPS and an assumed price-earnings ratio in year N, we have a terminal value--but this assumes a great deal. If one makes the assumptions that the price-earnings ratio in year N will be the same as at present, that earnings per share will grow at a constant rate g, and that dividends will continue to be a constant percentage of earnings, then it can be shown that the equation expressed above can be reduced* to the simple form:

$$R = \text{Shareholders' Discount Rate} = \frac{\text{DIV}}{\text{Price}} + g \; . \qquad (7)$$

This means that the cost of common equity is reduced to the expected dividend yield plus the expected growth rate in earnings per share which, according to previous assumptions, also equals the growth rate in market price and in dividends.

Although grossly oversimplified, this is an appealing concept of the cost of equity capital in that it reduces the considerations to two commonly observed variables which undoubtedly play a major role in determining market value in the real world. One can observe historical trends in these values and extrapolate them into the future. The problem is that the simplification does not fit the real world. Price-earnings ratios do change, as do dividend payouts and rates of growth in earnings per share. This makes the analysis considerably more complex. Investors have different investing horizons, and the expectations will be strongly influenced by the Nth period chosen for terminal date.

Under these circumstances a precise mathematical formulation that attempts to capture all the nuances of the real world is a practical impossibility. As a practical matter, the best one can hope for in deriving a cost of equity capital is a crude approximation that treats the two basic elements we have been discussing--dividends and capital gains. Since valid data on current shareholder expectations are beyond reach, a company can only rely on historical performance and use this as the presumed basis of any current extrapolations of future performance.

We should note that the two forms of benefit derived from common stock have different tax status--dividends are treated as regular income and stock price increases are regarded as capital gains. Thus, the individual investor will not be indifferent as to the mix of benefits. The tax considerations

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*See: Hunt, P. et al, Basic Business Finance, Richard Irwin, Inc., Fourth Edition.

Copeland, B., Jr., Land Economics, 54, No. 3, August 1978, p. 348.

Note that this equation is equivalent to saying that the current share price equals the current dividend/share divided by the difference between the investor's discount rate and the expected rate of growth in the dividend:

$$\text{PRICE} = \frac{\text{DIV}}{R-g}$$

tend to favor a higher proportion of capital gain. On the other hand, the dividend component may be considered the more assured benefit, and this may tend to offset the tax factor to some (unknown) degree.

e. The Average After-Tax Cost of Capital. The customary approach to the calculation of the average after-tax cost of capital is to sum the separate costs of debt, preferred stock, and common stock, each weighted by the proportion each source is expected to have in future financing.

After tax average cost of capital is defined as:

$$R = (1-t)C_d W_d + C_p W_p + C_c W_c \qquad (8)$$

where the C's stand for the separate capital costs of debt (d), preferred stock (p), and common stock (c); the W's stand for the proportions of each source in the capital structure of the firm; the subscripts indicate the contractual form, and t is the effective tax rated for the company. The costs involved are intended to be representative of what is expected to be appropriate in the capital market for the company in question in the foreseeable future. Likewise, the weights attached to each cost are the proportions of each source expected to be used in future financing. In the absence of specific information concerning management's plans, one would use the company's existing capital structure to determine these weights.

This calculated after-tax cost of capital is properly applied to funds invested from external sources as well as to internally generated funds--retained earnings, depreciation reserves, sinking funds, etc.

A long-term average cost of capital is calculated. The cost of capital should not be allowed to fluctuate merely because, at any point in time, for example, current financing happens to be by debt because it is considered the right time to take advantage of lower interest rates or to avoid a depressed equity market, etc. The average cost of capital concept separates individual investments from the related individual financing and treats all investments as if financed by a package of debt and equity in proportions considered appropriate for the firm. This provides a relatively stable standard over time.

An after-tax cost of capital is calculated in order to insure comparability across firms with different tax environments.

This approach for determining the average cost of capital is not without its problems. The simple summation of the costs of separate debt and equity contracts for the same firm assumes that these costs are independent of the proportions assumed. Many analysts would argue that these are not independent--that changes in the proportion of debt change the riskiness of the equity component and therefore its costs. They point out that a firm cannot assume any debt level it wishes and disregard the potential impact on the price-earnings ratio for its common stock. At some point, the gains derived from lower cost debt are eroded by the negative effect on market price of the common stock, as the financial risk becomes excessive in the minds of investors. They will demand higher compensation for assuming this risk. However, if one assumes that there exists a range of acceptable debt proportions for a given firm in a given industry or risk classification, within which the market price of the common stock is relatively insensitive to change in the debt proportions, this criticism is not as critical. Thus, if a company's planned debt levels are not noticeably out of line, we can in fact proceed to an aggregate cost of capital by summing the separate costs of debt, preferred stock, and common stock as in equation (8).

Another question revolves around whether the proportions of debt and equity should be measured in terms of book or market values. Although debt-equity proportions are commonly defined by borrowers and lenders in book value terms, the use of market values for the weighting of the common equity cost is more consistent with the basic investor orientation implied in the cost of capital versus opportunity cost of investment concept. The cost of capital is a standard designed to reflect the investor's perceptions of risk and reward, and it is through the market values that the investor communicates his preferences, including the matter of capital structure.

In conclusion, equation (8) provides a precise number for the cost of capital (and hence the discount rate for use in present value calculations), but it is important to remember the considerable subjectivity involved in its calculation. Several assumptions have been made. More specific information about a particular firm can serve to adjust and refine this estimate. Yet, in spite of the limitations and assumptions, this method does identify the key components of the cost of capital and the principal variables affecting their magnitude. It is in focusing attention on these elements of cost that the calculation serves an important and practical purpose.

D. RESEARCH REQUIREMENTS

Discussed in this section are the important areas for further research. Such research will enable the model to be refined and extended to reflect an increasingly sophisticated and representative understanding of the small power system capital investment decision-making process.

1. A More Accurate Treatment of System Lifetime Uncertainties and Salvage Values.

The cash flow requirements directly related to the initial capital investment are the return on the investment and the return of the capital investment, the depreciation annuity. Four major variables are involved in this calculation:

(1) The minimum cost of common equity capital (See paragraph "d" of subsection C.2)

(2) The probable average service life of assets

(3) The retirement dispersion pattern for assets (i.e., the way probable retirements will be scattered about average life)

(4) The ultimate net salvage value

At the present time, in the present model, it is assumed that service lifetimes are known exactly and that the net salvage value is zero. With these assumptions, the cash flow requirements for return on and of investor's committed capital are specified by equation (9).

Lifetime annual levelized cash flow required (for return + depreciation)

$$= (R_e + {}_{R_e}d)\ P \qquad (9)$$

where:

P = initial capital outlay, in depreciable facilities installed

R_e = minimum cost of common equity capital

${}_{R_e}d$ = $R_e/((1+R_e)^N - 1)$ = the annuity that will accumulate $1 in N years

N = service life = period of years from the date of initial purchase to the date of retirement from service, at which date the final recovery of the initial investment is required.

If one does not or cannot assume zero salvage value and a well-defined service life, then two adjustments to ${}_{R_e}d$ must be made:

(a) An adjustment for ultimate net salvage, by multiplying ${}_{R_e}d$ by (1-c) where c = ultimate net salvage, in percent of initial cost, installed, decimally expressed; and

(b) An adjustment for retirement dispersion, or the probability that retirements will not occur at any single predictable date.

Paul H. Jeynes (Ref. 5-5) points out that the annuity for a given probable life is not the same as that for when the identical life is certain. He states: "Failing to allow for dispersion can be about as important as a 50% error in estimating service life. Ignoring dispersion, as most people do, can result in unsound decisions."

Hence, the inclusion of the notions of probable service life, retirement dispersion, and salvage value is considered to represent an important future upgrading in the capabilities of STEAM.

2. Simulation Capability

With respect to the performance aspects of solar power systems, the model requires as input the initial price tag for the system and the amount of energy such a system produces each year. At the present time, the model assumes a given capacity rating (e.g., 10,000 kWe) for the desired power system, and uses the Burns & McDonnell methodology (Ref. 5-6) to size the solar system:

$$\text{AREA} = \frac{SM}{I_t} \times \frac{C}{n_c n_t n_x} \qquad (10)$$

where:

SM = solar multiple, which is the ratio of the maximum available thermal receiver power to the thermal power corresponding to the rated electrical capacity of the solar thermal power system

C = rated electrical capacity of the solar thermal power system, kW

I_t = receiver intensity rating, which is the level of direct normal insolation at which the solar thermal power system reaches its rated thermal receiver power, kW/m^2

η = efficiency, per unit. The subscripts indicate subsystem efficiencies: c = collector, t = transport, x = conversion.

The model then calculates the total kWh produced per year at that capacity rating by multiplying the capacity rating by the number of hours/year for which the sun shines at an intensity greater than or equal to I_t, the receiver intensity rating. For example, when C = 10,000 kW and I_t = 0.9 kW/m^2, the number of hours/year of insolation with "quality" greater than or equal to 0.9 kW/m^2 equals about 2740 hours per year (or 7.5 hrs/day) for an optimal Southwest United States location. Thus, the solar plant can produce (without storage) 27,400,000 kWh/year.* This means that, for a plant with a constant yearly demand (8760 h/yr) for power of 10 MWe, the nominal capacity factor for the system is 2740/8760 = .31. To increase the capacity factor beyond this, one needs storage or a hybrid firing capability. The 1978 EPRI Technical Assessment Guide (Ref. 5-7) indicates that one hour of storage produces about 200 hours per year of running time. Thus, if one wanted to operate at a capacity factor of 0.35, one needs (assuming a storage throughput efficiency of .85):

$$\frac{(.35)(8760) - 2740}{(200 \text{ hrs})(.85)} = 1.9 \text{ hours of storage.} \qquad (11)$$

This much storage requires additional collector area for charging. If the collector area, assuming no storage, is defined as A, then the additional collector area required by the storage requirement = A', where:

$$A' = A \left(\frac{\text{storage hours required}}{7.5 \text{ hours}}\right) \qquad (12)$$

These calculations then fix the collector cost (via A + A', the total collector area required), engine, receiver, transport and balance of system costs (via C, the system's capacity rating), and storage costs (via the number of storage hours required). These calculations also define the capacity factor and the amount of energy per year the system can provide.

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*This number is subsequently downgraded by consideration of scheduled maintenance and forced outage rates.

This method for determining the initial cost and energy output of solar thermal systems is obviously very approximate. (It is noteworthy though that performing the calculation using 1985 performance figures yields as a result a solar system whose cost/kWe is very close to the cost goal (in $/kWe) for 1985 vintage systems!) No provision is made for understanding how the solar system interfaces on an hourly basis with insolation, the other power production methods a firm or utility might possess and have available for dispatch, or with the energy demand curve to be satisfied. Hence, there is no consideration of the effective load carrying capability or capacity factor of the solar system.

This then represents an area of needed expansion of the model. It is envisioned that a separate hourly simulation computation submodel will be developed to provide the appropriate inputs to the STEAM.

3. The Inclusion of Risk in the Cost of Capital

The concept of the cost of capital is commonly accepted as the standard for evaluating or comparing new investment opportunities. The use of this concept in investment decision-making is consistent with the basic purpose of investment: to add to the value of the owner's equity. That value can be increased only if the incremental profit realized in the new investment exceeds the cost of capital necessary to obtain the added net income. The cost of capital provides the connecting link between financing decisions on the one hand and investing decisions on the other. However, the average cost of capital cannot be used blindly (as a reference to evaluate the worth of a calculated IROR, or to serve as a discount rate in a net present value calculation), with no consideration for risk differentials. To apply one standard to all investment proposals where the forecast benefits have not been adjusted for risk would favor high-risk proposals and discriminate against low-risk proposals. It is true that the cost of capital, if properly calculated, contains the collective judgment of the stock market on the overall risk characteristics of the firm. Yet, for opportunities that are clearly more risky, a premium over the cost of capital would be expected, and for those less risky, a discount would be appropriate. The average cost of capital is a reference point, with the direction of required risk adjustment clear but its magnitude uncertain.

Edward Katz and Stephen Schutz (Ref. 5-8) utilize portfolio theory and the capital asset pricing model to provide a framework for folding risk into economic analysis. In this paradigm, the cost of capital is estimated by looking at the market-oriented risk associated with a project, and linking this to an estimated market price of risk to compute the appropriate capital charge. They use this framework to capture the diversification benefit of on-site solar systems. They state:

> "An individual's calculation of the economic return on the investment in on-site solar heating cannot easily quantify the value of this technology as a hedge against future oil embargoes, macro-economic fluctuation, or other energy supply uncertainties. The public utility, on the other hand, is exposed to these market-oriented risks. Utility investment in on-site solar systems can provide some diversification. This benefit must be folded into the engineering economic return to estimate a final figure of merit in given circumstances."

The ability to determine financial risks for various energy technologies is imperative for any methodology which seeks to provide a useful tool for real-world decision making. The Kahn and Schutz work was a study of a set of financial strategies designed to accelerate the penetration of on-site solar heating and cooling systems. It is anticipated that the concepts developed by them can be extended to other solar systems and to non-utility owners, and incorporated at some future date into the STEAM.

SECTION VI

MARKET PENETRATION ANALYSIS: A REVIEW AND CRITIQUE

The successful development of a new technology depends on an accurate analysis of its market. Market penetration modeling is the principal component in the market analysis of dispersed solar thermal energy technologies. The solar energy market penetration models are used to project the demand for a particular solar technology in a given market. Alternative solar technologies may thus be evaluated and compared in order to concentrate current, limited RD&D funds in those which appear to be the most viable. Because of the pivotal role market penetration modeling could have in determining the development of dispersed solar thermal energy technologies, it is important to understand the analysis used in market penetration modeling as well as its limitations. The purpose of this section is to examine this analysis and delineate its limitations.

Since market penetration analysis is only one of several components of a market penetration model, this section begins with a general discussion of solar market penetration models. However, as market penetration analysis is acknowledged to be the most crucial and uncertain component of a solar market penetration model, the emphasis of this paper will be on this component. The underlying structure of most market penetration analyses is that of diffusion processes. Thus, Subsection B examines the properties of a generalized diffusion model and its underlying assumptions. A number of distinct diffusion models have been developed and several of these have been used as the basis of the market penetration analysis proposed or implemented in solar market penetration models. In Subsection C, therefore, the most relevant special diffusion models are derived as special cases of the general diffusion model of Subsection B and their applicability is discussed. Drawing on the foundations laid in Subsections B and C, Subsection D critiques the market penetration analyses of the five most prominent market penetration models for solar thermal energy technologies. Finally, this section concludes with a subsection reiterating the limitations of the market penetration analyses used in solar energy market penetration models and offering suggestions for further analyses.

A. SOLAR ENERGY MARKET PENETRATION METHODOLOGY

The methodology used in all solar energy market penetration models is a deterministic simulation with six component parts. The six components are illustrated in Figure 6-1.

The first component, market classification and segmentation, divides the universe of all possible markets for a solar energy system into functionally similar ones. Although they may vary according to feasibility and expected uses of the model, the usual classifications are geographic region (on a basis of average values of insolation and climate), types of solar energy technologies to be considered, and their uses (e.g., hot water, electricity generation).

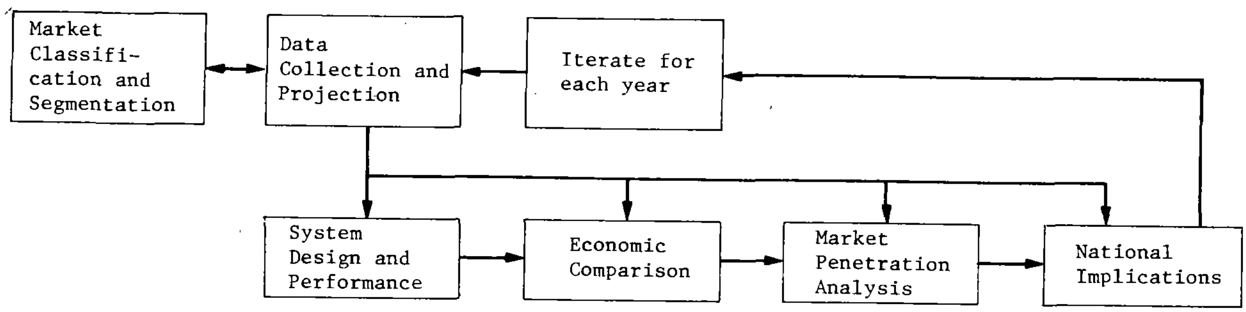


Figure 6-1: Components of a Solar Energy Market Penetration Model (Source: Ref.6-18)

The second component begins with the collection of current data, by market, on variables such as: (i) price of conventional fuels, (ii) relative market shares of conventional fuels (iii) climatic characteristics, (iv) solar insolation, (v) energy demand, and (vi) costs of solar system components. Once this data is available future values must be forecast.

In the third component of the solar energy market penetration model, a small number of representative solar and conventional energy systems are designed for each market and their performance is simulated. These design and performance simulations will be used in the economic comparisons of the fourth component. Thus, they must be accurate enough to determine the solar and backup component sizes (e.g., collector area, storage capacity) and the percent of the annual energy load supplied by the solar energy system.

The fourth component makes economic comparisons of conventional and solar energy systems based on the values of the data forecast in the second component. The criteria used to make these economic comparisons vary but may include payback period, life-cycle cost, and years to positive savings.

Assuming the choice of an energy system is based solely on economic criteria, the potential market share of each of the solar technologies is calculated for each market in the fifth component, market penetration analysis. The market penetration of solar technologies, is based on the S-shaped logistic (learning) curve. A representative curve is shown in Figure 6-2. The general shape of the curve reflects a postulated behavioral lag in the adoption of a new technology. The vertical axis always measures the percent of the market adopting the new solar technology. In solar market penetration analysis, the horizontal axis usually measures the economic competitiveness of the solar technology. However, most analyses of the diffusion of innovations use time as the measure of the horizontal axis, as shown in Figure 6-3 of Subsection B.

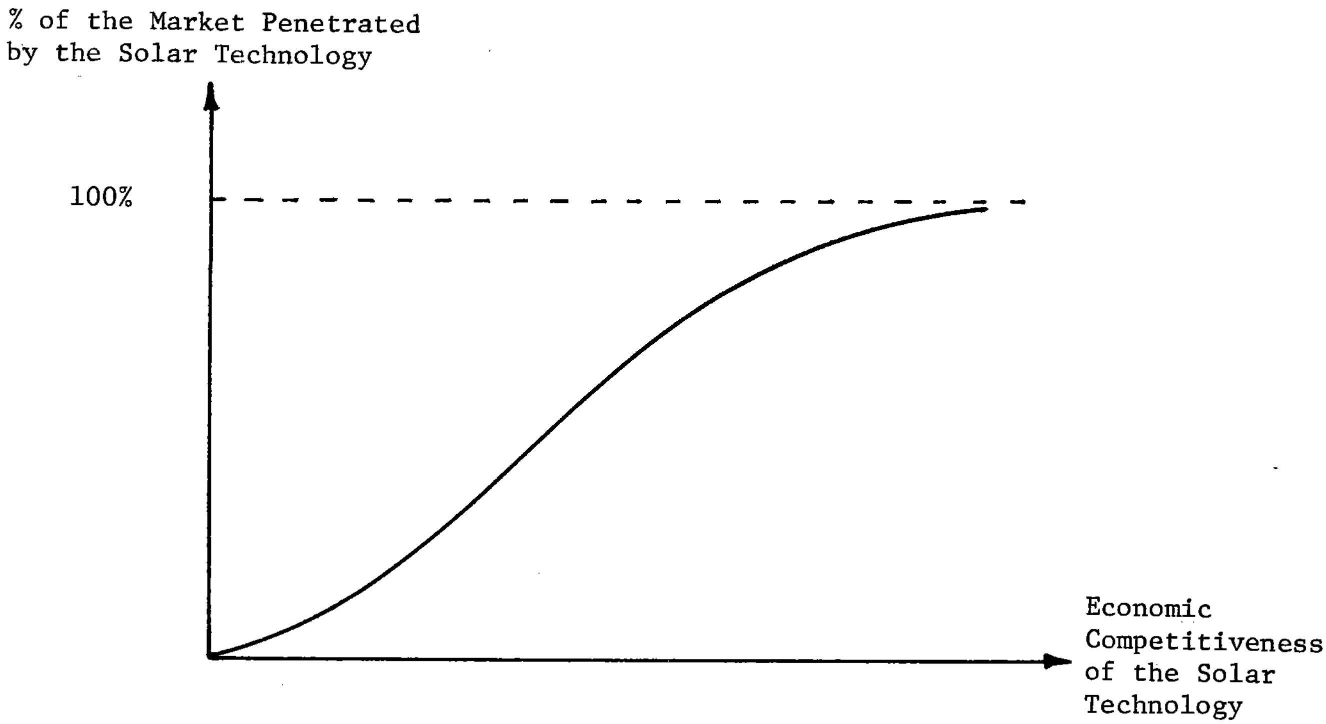


Figure 6-2: An S-shaped Logistic Curve

The assumptions underlying these two distinct representations of logistic curves is subtle but important. If the horizontal axis measures economic competitiveness, then the behavioral lag represented by the logistic curve is based on changing economic competitiveness. When the solar technology is only marginally better than the conventional technology, few innovators will adopt the solar technology. However, as the solar technology becomes more clearly economically superior a "bandwagon" effect occurs which gradually dissipates as the majority of the market is captured. Thus the percent of the market captured by the solar technology approaches 100%. On the other hand, if time is used as the measure on the horizontal axis, then the behavioral lag is due to a combination of several factors, including the economic advantage of the solar technology, the initial uncertainty associated with the solar technology and the rate of reduction of this initial uncertainty, and the extent of the commitment required to adopt the solar technology (Ref. 6-12). Further, if time is used as the measure of the horizontal axis, the percent of the market captured by the solar technology may be less than 100% (see Figure 6-3, below). This distinction is important because almost all empirical evidence in support of the logistic curve relates market penetration to time rather than economic competitiveness, thus undermining the degree of confidence one can place in solar market penetration analysis.

The sixth and last component of solar market penetration models is an assessment of the national impacts of the solar energy technologies. It is at this point that the conventional energy displaced by solar energy can be computed by multiplying the market size (from the second component) by the percent of market penetration (from the fifth component). Also, government incentives can be evaluated and compared against a baseline case without incentives.

Finally, components one through six are usually iterated to determine the market penetration of solar energy in subsequent years. Thus, the methodology is simulation. Because the simulation contains no probabilistic components, it is deterministic.

In October, 1977, a workshop was held at the Solar Energy Research Institute (SERI) to review four of the most prominent solar market penetration models. Methodological discussions at this workshop, as reported by Schiffel, Costell, Posner and Witholder (Ref.6-18) centered on the theoretical bases for solar market penetration models and their structure.

It was pointed out that solar market penetration models are not based on fundamental social science theory. The lack of a theoretical foundation results in the absence of a causal explanation of market behavior. This, in turn, means there is a reduced ability to accurately simulate behavior because the structural features of the model may not capture reality. Further, the absence of clearly specified behavioral relationships makes it virtually impossible to test the models. Also, participants in the SERI workshop felt that solar market penetration models may be biased by emphasizing only the demand side of solar technology. Finally, it was pointed out that the logistic curves have been used only with historical data; thus they are explanatory not predictive.

As a consequence of these perceived defects it was concluded that "only limited confidence can be placed in the (solar market penetration) models." (Ref. 6-18). In the following sections it will be shown that even this limited confidence must be further qualified.

B. DIFFUSION PROCESSES

Following Rogers and Schoemaker (Ref. 6-17) a diffusion process will be defined as the process by which innovations spread to members of a social system. Diffusion is to be distinguished from the adoption process which refers to the sequence of stages through which innovation progresses from first awareness to adoption. It should be noted that a diffusion process is not the physical diffusion of adopters, but the movement of innovation from adopter to adopter.

Diffusion processes were probably first systematically studied in relation to the mathematical theory of epidemics, and the most sophisticated mathematical work and most serious empirical studies of these processes have been in this area (Ref. 6-1). Social scientists were quick to realize that diffusion processes were not only useful in describing the contagion of a disease, and to date it is estimated that there are over 2500 publications available on the diffusion of new ideas, practices, technologies, and products. However, regardless of the type of phenomena being diffused, the major aspect of the diffusion process being studied is the time pattern of the spread of the innovation. Recently, Mahajan and Schoeman (Ref. 6-11) developed a generalized model of the time pattern of the diffusion process. The generalized model developed in this section is based on their model.

Let $f(t)$ denote the proportion of a fixed population who adopt the innovation under consideration at time t, and let $F(t)$ denote the cumulative proportion who adopt to time t. Hence,

$$F(t) = \int_{t_o}^{t} f(t)dt, \quad \text{or} \quad dF(t)/dt = f(t).$$

It is assumed that $F(t)$ and $f(t)$ are continuously differentiable and that $f(t)$ is unimodal. Let F_x be the maximum proportion of the population who will eventually adopt the innovation. Then $[F_x - F(t)]$ is the cumulative proportion who have not adopted the innovation by time t but who will eventually adopt it.

In order to mathematically describe a diffusion process it is necessary to make an assumption about the rate of diffusion, $f(t)$. The most general assumption describing the deterministic rate of diffusion of an innovation is that it is some combination of the proportion adopting the innovation multiplied by the proportion not adopting the innovation plus a proportion of those not adopting the innovation. Mathematically, this means

$$(1) \qquad f(t) = dF(t)/d(t) = aF(t)[F_x - F(t)] + b \; [F_x - F(t)].$$

where $a \geq 0$ and $b \geq 0$. The constant, a, can be interpreted as the index of influenced adoption, so that $aF(t)[F_x - F(t)]$ can be viewed as the imitation component. Similarly, b can be interpreted as the index of uninfluenced adoption so that $b[F_x - F(t)]$ can be looked on as the innovation component.

Before solving the diffusion process given by equation (1), consider the special case of equation (1) where $b = 0$, i.e.,

$$(2) \qquad dF(t)/dt = aF(t)[F_x - F(t)]$$

and $a > 0$. Given the above interpretation of a and b, this process may be thought of as a pure imitation diffusion process. It has played a prominent role in the literature on the diffusion of technological innovations and solar energy market diffusion analyses.

Note that an assumption of an homogeneous mixing of the population is embodied in the diffusion process given by equations (1) and (2), which is usually not acknowledged in the literature, (for an exception see Ref. 6-6). Underlying equation (2) and the first term of equation (1) is the assumption that the number of contacts between those who have adopted the innovation and those who have not (but will) is proportional to the product of the proportion of each. In a population of potential adopters where each decision unit has an equal number of contacts with every other decision unit, such an assumption correctly describes the situation. However, if this assumption is not met, as is usually the case, then a serious bias may be introduced into the model.

Also embodied in equation (2) is a trivial example of what is called a threshold theorem in mathematical epidemiology. In order for diffusion to occur, it must be the case that $dF(t)/dt > 0$. This implies that $F(t_o) > 0$. Thus, in order for diffusion to occur according to the model given by equation (2), initially there must be a positive proportion of the population who have already adopted the innovation.

Equation (2) is a first order differential equation whose solution is

(3) $$F(t) = \frac{F_x e^{(aF_x t) + c}}{a + e^{(aF_x t) + c}}$$

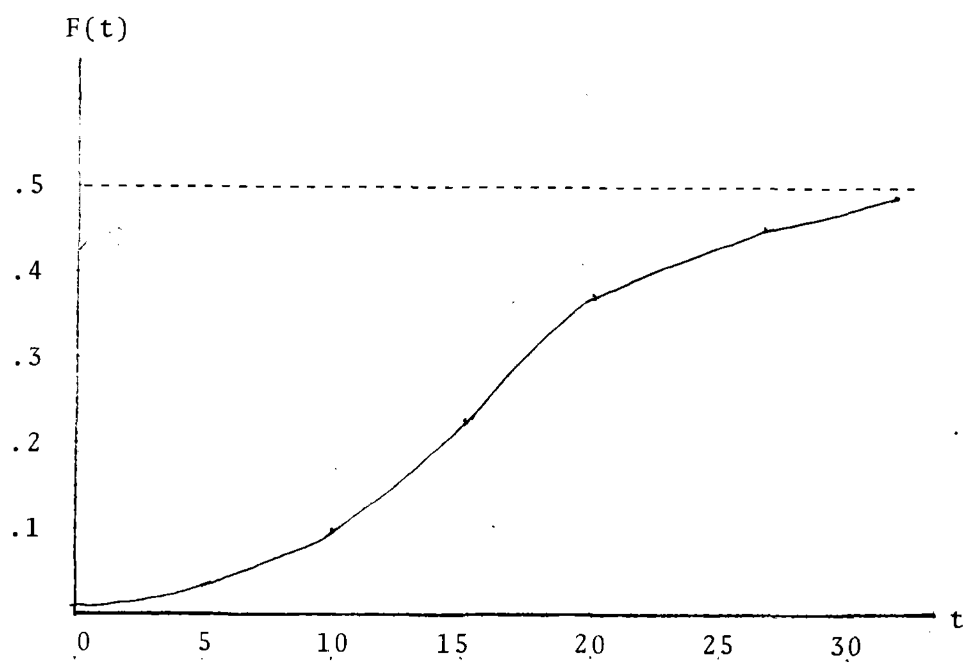
where c is the constant of integration. The unique solution of equation (2) may be found on specification of an initial condition. Thus, if it is assumed that $F(t_o) = F_o$, then substituting this condition into equation (3) it follows that

$$c = \ln \left[\frac{a\, F_o}{F_x - F_o}\right] - a\, F_x t_o$$

Substituting for c in equation (3), the unique solution of equation (2) is found to be

(4) $$F(t) = \frac{F_x}{1 + \left(\frac{F_x - F_o}{F_o}\right) e^{-aF_x(t - t_o)}}$$

This is shown graphically in Figure 6-3 for $F_x = .5$, $F_o = .01$, $t_o = 0$, and $a = .5$.



t	F(t)
0	.01
5	.03
10	.10
20	.23
25	.46
30	.49
35	.50

Figure 6-3: A Pure Imitation Diffusion Process
Where $F_x = .5$, $F_o = .01$, $t_o = 0$, and $a = .5$

Using equation (3) and solving $dF(t^*)/dt = 0$ for t^*, the maximum diffusion rate occurs at

$$t^* = t_o - \frac{\ln (F_o) - \ln (F_x - F_o)}{a\, F_x}$$

Thus, since $F(t^*) = F_x/2$, the diffusion process given by equation (4) can be seen to be symmetric about t^*. Finally, evaluating the change in t^* as a varies yields

$$\frac{dt^*}{da} = \frac{\ln (F_o) - \ln (F_x - F_o)}{a^2}$$

Since $0 \leq F_o < F_x \leq 1$, it follows that $dt^*/da < 0$ so that any increase in the imitation index, a, will increase F(t) for all $t > t_o$, i.e., it will shift the logistic curve to the left.

Return now to the diffusion model given by equation (1). Because of its innovation component, $b[F_x - F(t)]$, the bias introduced by non-homogeneous mixing of the proportion of adopters and non-adopters will be diluted. However, unless $a = 0$ some bias will be present. Also, if $F(t_o) = 0$ in equation (1), then $dF(t_o)/dt = bF_x > 0$ as long as $b > 0$. Therefore, there is no threshold theorem for the diffusion process described by equation (1) as there was for the diffusion process described by equation (2).

Equation (1) is also a first order differential equation. Its solution is

$$F(t) = \frac{F_x e^{(b + aF_x)\, t + c} - b}{a + e^{(b + aF_x)\, t + c}} \tag{5}$$

where c is a constant of integration. As before, the unique solution to equation (1) may be found upon specification of an initial condition. Thus, if the initial condition is $F(t_o) = F_o$, then it follows that

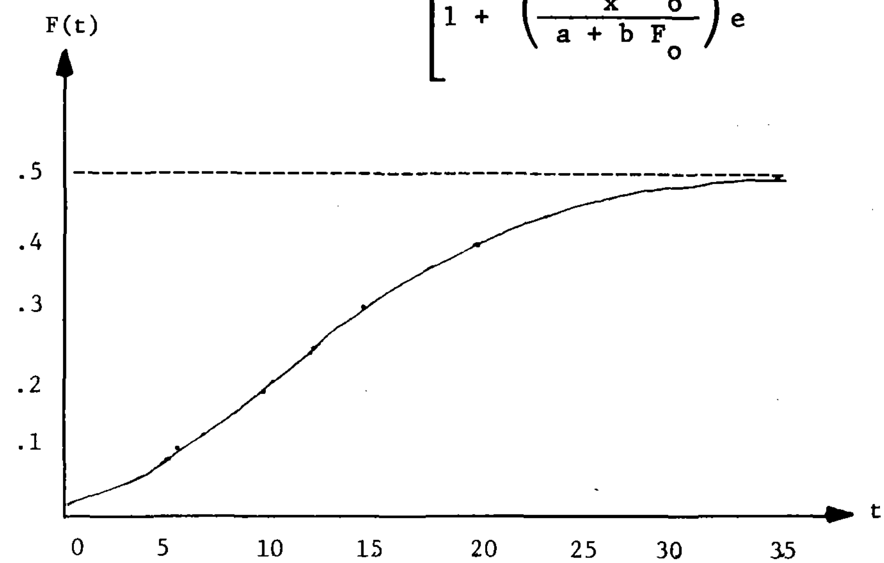
$$c = \ln \left[\frac{b + a\, F_o}{F_x - F_o}\right] - (b + a\, F_x)\, t_o$$

Substituting this expression for c back into equation (5), the unique solution of equation (1) can easily be seen to be

$$F(t) = \frac{F_x - \left[\dfrac{b\, (F_x - F_o)}{b + a\, F_o}\right] e^{-(b + a\, F_x)(t - t_o)}}{1 + \left[\dfrac{a\, (F_x - F_o)}{b + a\, F_o}\right] e^{-(b + a\, F_x)(t - t_o)}} \tag{6}$$

This is shown graphically in Figure 6-4 for $F_x = .5$, $F_o = .01$, $t_o = 0$, a = .3, and b = .02. Differentiating F(t), as given by equation (6) with respect to t, the diffusion rate can be seen to be

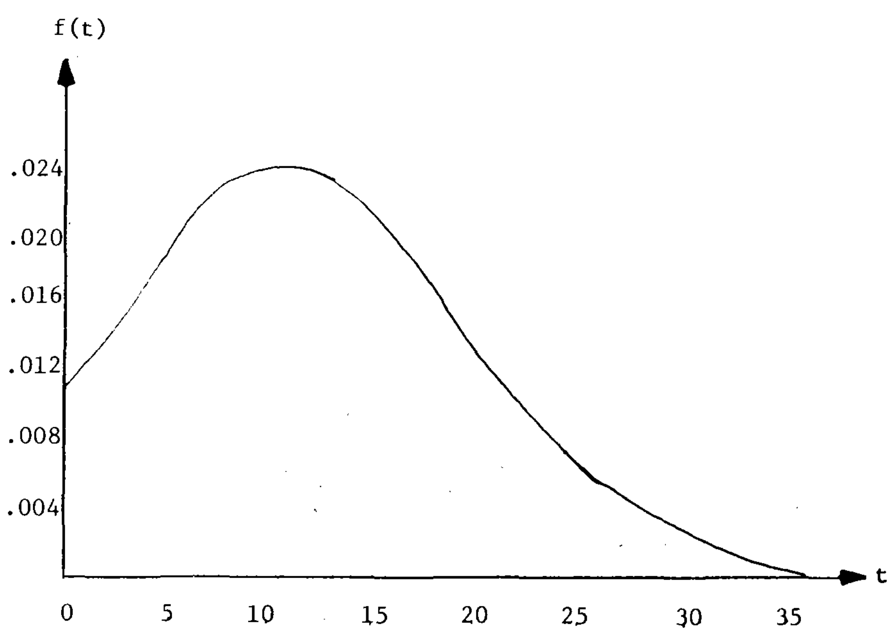
$$f(t) = \frac{\left(\frac{F_x - F_o}{b + a F_o}\right)(b + a F_x)^2 e^{-(b + a F_x)(t - t_o)}}{\left[1 + \left(\frac{a (F_x - F_o)}{a + b F_o}\right) e^{-(b + a F_x)(t - t_o)}\right]^2} \qquad (7)$$



t	F(t)
0	.01
5	.085
10	.19
15	.31
20	.40
25	.45
30	.48
35	.49

Figure 6-4: A Diffusion Process with
$F_x = .5$, $F_o = .01$, $t_o = 0$, a = .3 and b = .02

This is shown graphically in Figure 6-5 for $F_x = .5$, $F_o = .01$, $t_o = 0$, a = .3, and b = .02.



t	f(t)
0	.0113
5	.019
10	.024
15	.021
20	.014
25	.007
30	.003
35	.0016

Figure 6-5: The Rate of Diffusion with
$F_x = .5$, $F_o = .01$, $t_o = 0$, a = .3, and b = .02

From observation of Figure 6-4 in conjunction with Figure 6-5 it is apparent that, at least for the graphical example, F(t) is not symmetric about t^*. To verify that this is the case, set $f(t^*) = dF(t^*)/dt = 0$ and solve for t^*.

This yields

$$t^* = t_o - \frac{\ln(b + a F_o) - a (F_x - F_o)}{b + a F_x}$$

Thus, since $F(t^*) = (F_x/2) - (b/2a)$, the majority of the adoptions in the diffusion process given by equation (1) will occur after the rate of diffusion achieves a maximum.

To determine how the diffusion process changes as the parameters a and b change, it is necessary to investigate the signs of $\partial t^*/\partial a$ and $\partial t^*/\partial b$. It can be shown that if $t^* \geq 0$ then $\partial t^*/\partial a < 0$ and $\partial t^*/\partial b < 0$, i.e., that the logistic curve shifts to the left with an increase in either a or b.

As one example of how parameters of a diffusion model can be estimated, consider the problem of estimating the parameters (F_x, a and b) of the model given by equation (1). It is first necessary to discretize the continuous process by setting $f(t) = F(t + 1) - F(t)$. Substituting this relation into equation (1) and solving for $F(t + 1)$ yields

(8) $$F(t + 1) = bF_x + (aF_x - b + 1) F(t) - a [F(t)]^2 .$$

Setting $\alpha_1 = bF_x$, $\alpha_2 = aF_x - b + 1$, $\alpha_3 = a$, and

$$F(t) = \sum_{i=0}^{t} [F(t - i + 1) - F(t - i)],$$

equation (8) may be estimated using usual statistical procedures. However, although estimation of the model is relatively straightforward, its predictive value is, at best, uncertain. Chatfield (Ref. 6-6) shows that if a diffusion model predicts that production of a product will increase by a factor of ten in five years, the 95% confidence interval for that estimate will vary by a factor of 100 in either direction.

C. MODELS OF THE DIFFUSION OF INNOVATIONS

If an analytic model is used as the basis of the logistic curve of the market penetration analysis in a solar market penetration model, it appears to usually be based on a combination of one or more of the three most prominent models developed to explain the diffusion of innovations. These models were developed by Mansfield (Ref. 6-13) Blackman (Ref. 6-4) and Fisher and Pry (Ref. 6-9). A discussion of the Bass model (Ref. 6-2) is also included for comparative purposes.

1. The Mansfield Model

Edwin Mansfield (Ref. 6-13) was one of the first economists to attempt to model the diffusion of innovations. He made only two explicit assumptions about the diffusion processes his model describes. First he assumes that the entire population are potential adopters, i.e., $F_x = 1$. His second assumption is that there are no adoptors only in the infinitely distant past, or

$$\lim_{t \to -\infty} F(t) = 0 .$$

Using these two assumptions in conjunction with equation (5), it follows that $-b/a = 0$, or that $b = 0$. Thus the diffusion process postulated by Mansfield is a pure imitation diffusion process equivalent to that described by equation (2). Therefore, because of the threshold result associated with the pure imitation decision process, the Mansfield model implicitly assumes that $F_o > 0$ although no initial condition is specified in the model. Further consequences of $b = 0$ are the implicit assumptions that the logistic curve describing the diffusion process is symmetric and that there is homogeneous mixing of the populations of adopters and nonadopters.

Since no initial condition is specified by Mansfield for his model, if the condition $F_x = 1$ is substituted into equation (3), the solution of his model, in terms of the pure innovation process defined above, is

(9) $$F(t) = \frac{1}{1 + a\, e^{-(at + c)}}$$

The solution Mansfield offers for his model is

(10) $$m(t) = n\, [1 + e^{-(\ell - \phi t)}]^{-1}$$

where $m(t)$ is the number of adopters to time t, n the number of potential adopters, ℓ the constant of integration, and ϕ the parameter of the rate of imitation. That equations (9) and (10) are essentially equivalent can be seen by noting that in Mansfield's notation $F(t) = m(t)/n$, $c = \ell$ and $a = \phi$.

Mansfield rewrites equation (10) as

(11) $$\ln \left[\frac{m(t)}{n - m(t)}\right] = \ell + \phi t .$$

After postulating a relationship between ϕ and the innovation's profitability relative to the profitability of alternative investments, the size of the investment relative to firm assets and industry peculiarities, he uses equation (11) to estimate the market penetration parameters ℓ and ϕ. Using this procedure, he estimates market penetration of twelve innovations in the bituminous coal, iron and steel, brewing, and railroad industries. He concludes that "the calculated curves generally provide reasonably good approximations to the actual ones." (Ref. 6-14).

2. The Blackman Model

Wade Blackman (Ref. 6-4) alters Mansfield's model by postulating the relationship between the figure of merit, not market penetration, and time. Following Mansfield, Blackman assumes that

$$\lim_{t \to -\infty} F(t) = 0$$

so that b = 0. Thus Blackman's model is of a pure imitation diffusion process so that the qualifications previously discussed with regard to this type of model hold.

Unlike Mansfield, however, Blackman does not specify a value for F_x. In a further divergence with the Mansfield model, Blackman does specify the initial condition, $F(t_o) = F_o$. Thus the solution of the Blackman model is given by equation (4). To show its equivalence to the solution of the Blackman model, it will be convenient to rewrite equation (4) as

$$\ln\left[\frac{F(t)}{F_x - F(t)}\right] = -\ln\left[\frac{F_x}{F_o} - 1\right] + a F_x (t - t_o) \tag{12}$$

The solution given by Blackman for his model is

$$\ln\left[\frac{f(t)}{F - f(t)}\right] = -\ln\left[\frac{F}{F_o} - 1\right] - \alpha (t - t_1) \tag{13}$$

where f(t) is the figure of merit of the innovation at time t, F is the maximum figure of merit, t, the time at which f(t) becomes positive, and α an imitation index. Clearly all that is needed to show the equivalence of equations (12) and (13) is the reinterpretation of F(t) as the figure of merit at time t.

Blackman postulates that his imitation index, α, is a function of the perceived payoff of the technological progress, the investment required to achieve progress and the innovative characteristics of the industry in which progress is achieved. He uses this postulated relationship in conjunction with equation (13) to examine the electric utility and auto industries. Although he appears to achieve an acceptable explanation of the change in figure of merit over time, poor data and questionable techniques detract from Blackman's results.

3. The Fisher-Pry Model

Although Fisher and Pry (1971) published their model prior to the Blackman (1974) model, the Fisher-Pry model is essentially a special case of Blackman's model. Like Mansfield and Blackman, Fisher and Pry assume

$$\lim_{t \to \infty} F(t) = 0.$$

so that a = 0 and the previous caveats about this class of models hold. Further, following Mansfield, Fisher and Pry assume $F_x = 1$, however they continue by also assuming that $a = 2\alpha$ and $F(t_o) = 1/2$. Substituting these assumptions into equation (4),

(14) $$F(t) = \frac{1}{1 + e^{-2\alpha(t - t_o)}}$$

is obtained. Dividing equation (14) by 1 - F(t) yields

(15) $$\frac{F(t)}{1 - F(t)} = e^{2\alpha(t - t_o)}$$

which is precisely the solution given by Fisher and Pry.

Using equation (15) Fisher and Pry proceed to examine the model's explanatory properties in the substitution of one product for another. In particular, they investigate the substitution of synthetic for natural fibers, plastic for leather, synthetic for natural rubber among others. As they present no statistical evidence, conclusions about the usefulness of their model must be withheld.

4. The Bass Model

The final model to be considered in this subsection, that of Frank Bass (Ref. 6-2), differs from the three preceding models in that it includes both innovators and imitators. That is, a = 0 and b = 0. Because, as was pointed out in Subsection B, there is no threshold of adoption necessary for diffusion to occur in this type model, Bass is able to assume $F(t_o = 0) = 0$. Finally, it is implicitly assumed by Bass that $F_x = 1$.

Substituting these assumptions into equation (6) it becomes

(16) $$F(t) = \frac{1 - e^{-(b + a)t}}{1 + \left(\frac{b}{a}\right) e^{-(b + a)t}}$$

which is precisely the solution given by Bass if one substitutes q for b and p for a.

Bass rigorously tests his model for its explanatory power against the sales over time of eleven consumer durables. He concludes that "the data are in fairly good agreement with the model" (Ref. 6-2). He also considers the predictive power of his model with limited data using sales of color television as the example. He concludes that "the parameter estimates are very sensitive to small variations in the observations when there are only a few observations" (Ref. 6-2), and "the goodness of the predictions depends on "one's personal criterion of goodness" (Ref. 6-2).

In conclusion, several additional limitations of all the models discussed in this section should be noted. First, all of the models have been tested successfully only on an ex post basis. Thus their predictive power is open to significant doubt. Secondly, they appear to be valid only for innovations whose technologies are well developed. The reason for this is that a new technological breakthrough would imply different parameters of the model and hence a different logistic curve. Finally, all the models assume a relatively stable market for the innovation. Should a significant, new market for the innovation develop, it would imply a shift in F(t) and thus a change in the parameters.

D. SOLAR MARKET PENETRATION ANALYSIS

In this subsection, the market penetration analysis of five of the most prominent solar energy market penetration models will be briefly reviewed. These models are the GE (Ref. 6-10), SPURR (Ref. 6-16), SRI (Ref. 6-20), SHACOB (Refs. 6-11, 6-15), and ISTUM (Ref. 6-7) models. These models may be subdivided into two categories, those that are ostensibly based on an analytical diffusion model--the GE and SPURR models, and those based on ad hoc diffusion models--the SRI, SHACOB and ISTUM Models.

1. The GE Model

The model General Electric proposes to use as a part of their study, "Effects of Systems Factors on the Economics of and Demand for Small Solar Thermal Power Systems," being undertaken for JPL contains a market penetration analysis analogous to the Mansfield (Ref. 6-13) model as implemented by Blackman (Ref. 6-3). As such it suffers from all the limitations of Mansfield's original model, as discussed in Subsection C, and no further comments are necessary.

2. The SPURR Model

The market penetration analysis of Mitre Corporation's SPURR (System for Projecting the Utilization of Renewable Resources) model is carried out by their METREK market share function. The METREK market share function is given by the following equation

$$Y = \frac{1}{1 + 1/\left[F \tanh(\hat{t}) e^{(1-1/F)\hat{t}}\right]}$$

where

$$\hat{t} = \left(\frac{t - t_o}{\tau}\right)^2$$

and Y is the solar share, F is a figure of merit, t_o is the year in which the technology becomes generally available, and τ is a scale factor representing the number of years required for the technology to mature.

It is claimed (Mitre Corporation (Ref. 6-16)) that the METREK market share function is similar to the Fisher-Pry model. This is true only at the most superficial level; both use the figure of merit concept and both market share functions include hyperbolic tangents. As used by the SPURR model, changes in the figure of merit can drastically alter the shape of the logistic curve and even destroy its basic S-shape (see Figure 6-6).

Unlike any diffusion model described in the proceeding subsections, the METREK market share function is a particular solution of a second order partial differential equation (which in engineering mechanics describes the deflection of a beam due to applying a force). Further, an exact solution requires the specification of a continuous function, monotonically increasing from 0 to 1, tanh ($\hat{t}$) was an arbitrary choice from this class of functions.

Clearly, the METREK market share function is unrelated to the basic diffusion processes discussed above. This absence of an established foundation raises questions as to the validity of the model.

3. The SRI Model

The market penetration analysis of SRI International's solar market penetration model is unabashedly an ad hoc model. The market penetration of a solar technology is calculated in two steps. First it is postulated that the maximum market share of the solar technology in equilibrium is a function of the relative price of the solar technology, P_s, and alternative fuels, P_a, as well as a measure, γ , of market imperfections, price variations and consumer preferences. The assumed relationship of these variables to the equilibrium market share of the solar technology is

$$\text{Equilibrium Market Share} = \frac{1}{1 - \left(\frac{P_s}{P_a}\right)^{\gamma}}$$

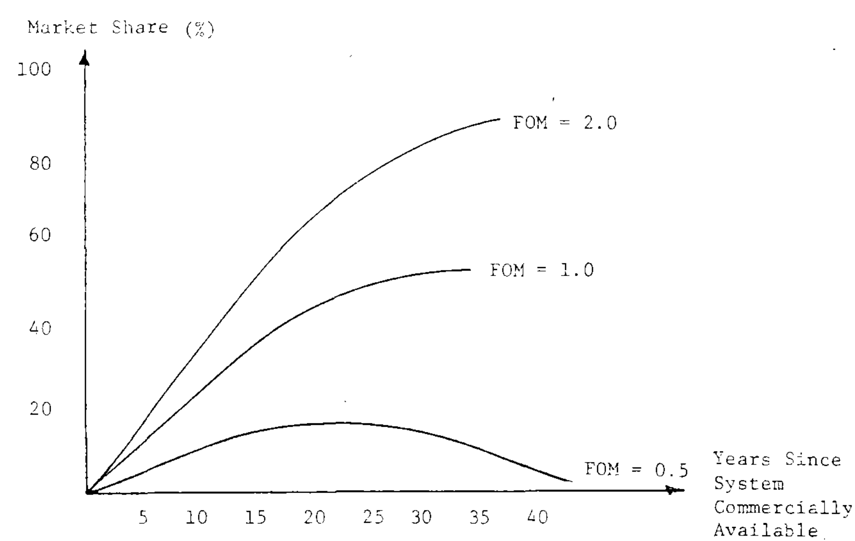


Figure 6-6: SPURR Market Share Function
(Source: Mitre Corp.)

No justification, other than their own experience, is given for the particular functional form and estimation of the value of γ. Thus, it is impossible to criticize or justify the particular functional form or value of γ used except in terms of the SRI authors' personal experience.

The equation of the logistic curve, which is referred to as the dynamic market response curve, in the SRI model is

$$F\left(\frac{n}{h}\right) = \frac{1}{1 + \left(\frac{h}{n}\right)^{\alpha}}$$

where h is the half life (time required for one-half the market to respond to the entrance of the new technology), n is the number of years since the introduction of the new technology, and α is a response parameter. A graphical representation of this dynamic market response curve is shown in Figure 6-7 for $\alpha = 4$. That this curve exhibits the characteristic S shape of a logistic curve is readily apparent. However, no justification for the particular functional form or value of the parameter α, except for experience, is given. Thus again no criticism or derivation of the functional form can be made. It is interesting to note that the dynamic market response function is symmetric about $(h/n) = 1$, so that presumably the market penetration is the result of some pure imitation diffusion process and therefore suffers from all the limitations of this type of diffusion process.

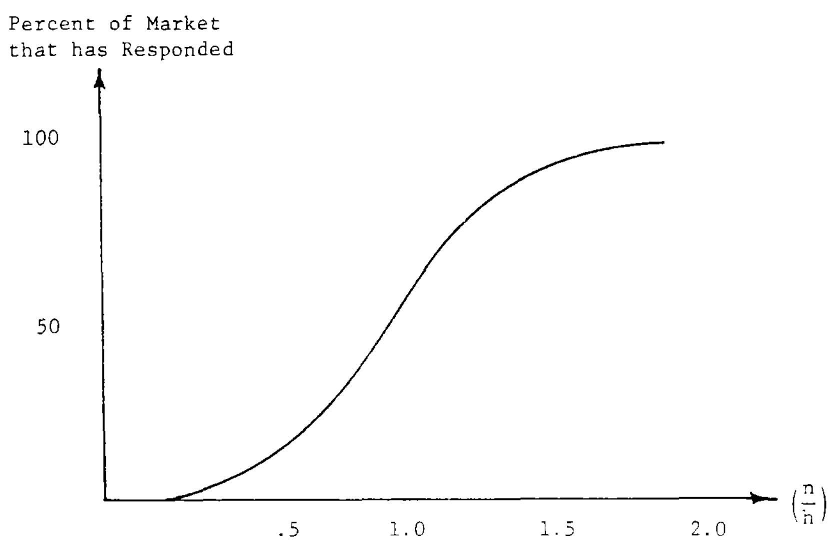


Figure 6-7: SRI's Dynamic Market Response Curve for $\alpha = 4$. (Source: SRI International)

4. The SHACOB Model

Unlike the other market penetration analyses discussed here, the SHACOB (Solar Heating and Cooling of Buildings) Commercialization Model relates percent of market penetration by the solar technology to the zero interest

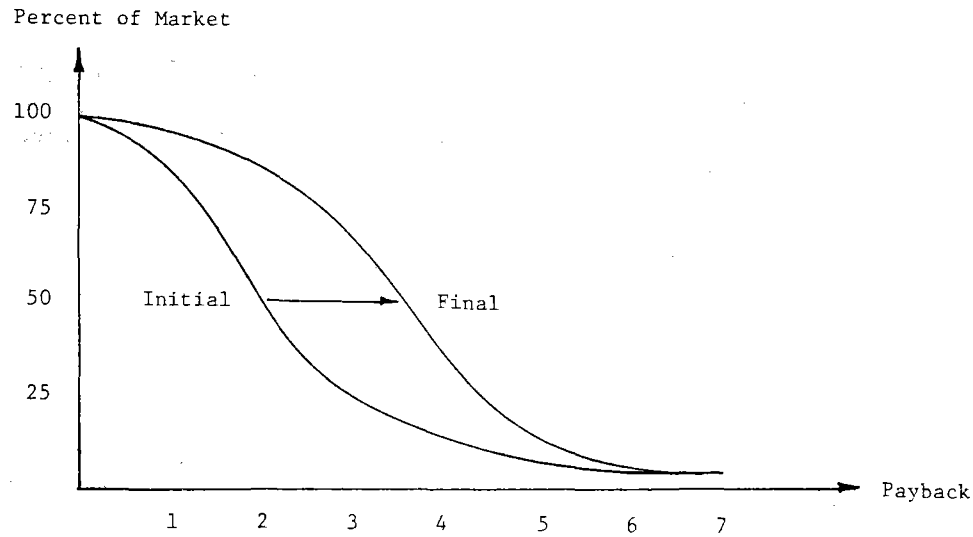


Figure 6-8: SHACOB Penetration Curve Initial and Final Configurations (Source: Arthur D. Little, Inc.)

payback. The payback period is defined as the inverse of the figure of merit and thus ranges from 0 (as the figure of merit approaches infinity) to ∞ (as the figure of merit approaches zero). As a result, the characteristic S shape of the logistic curve is transposed to a "backward" S shape (see Figure 6-8). Further, as the payback period approaches zero (the figure of merit approaches infinity) the percent market penetration approaches 100%.

The SHACOB market penetration analysis is unique in another way; in order to take into consideration non-financial characteristics which can influence the market penetration of a solar technology, it is assumed that SHACOB's transposed logistic curve shifts to the right as the market develops (over time). This is shown in Figure 6-8. The shift of the logistic curve to the right is accomplished by establishing a trade-off between the payback period and the non-financial characteristics of the solar technology.

Although no derivation is given for the penetration curve in the SHACOB model and it is justified only in a very general way, it could be speculated to be based on the Blackman (Ref. 6-4) model because of its use of the figure of merit (inverse of the payback period). However, this is contraindicated by the penetration curve (see Figure 6-8). Thus, the basis of the SHACOB market penetration curves remains an open question.

5. The ISTUM Model

Energy and Environmental Analysis, Inc.'s Industrial Sector Technology and Use Model (ISTUM) replaces their earlier Market Oriented Program Planning Study (MOPPS) model. In this regard, it is interesting to note that while the MOPPS model was based on the analytic diffusion models of Mansfield (Ref. 6-13) and Blackman (Ref. 6-4), the ISTUM is an ad hoc model.

The market penetration analyses of the ISTUM model has two components--a nominal market share component and an actual market share component. Since technology cost inputs and fuel price inputs of the ISTUM model are given as distributions of possible prices, the calculation of the nominal market share of a technology requires a statistical procedure. First, the maximum share of each market that each technology could achieve (referred to as its maximum market share) is specified. Then probability distributions over the total costs of each technology in each market are specified. Finally, a statistical procedure based on each technology's probability distribution of total costs is used to determine each technology's nominal market share as a fraction of its maximum market share. Thus, the nominal market share represents the fraction of the market in which a technology is theoretically preferable to the alternatives.

The actual market share of a technology (which is analogous to the percent of market penetration of a technology) is based on linear behavioral lag in the ISTUM model. This is equivalent to assuming the logistic curve is linear and is unique to the ISTUM model. The number of years required for actual market share of a technology to equal its nominal market share is referred to as the behavior lag time. The actual market share in a given year is the fraction of the behavioral lag time since the technology was introduced multiplied by the nominal market share. The behavior lag time, however, is a linear function of the "behavioral lag multiplier" which is, in turn, a linear function of the nominal market share. Only the most general justification was given for this functional form which apparently has no basis in theory or experience.

E. CONCLUSIONS AND RECOMMENDATIONS

Simply because an analysis has a quantitative foundation does not guarantee that the data which are generated are meaningful. Valid data can be entered in a spurious model to yield meaningless numbers. This appears to be the case with solar energy market penetration analysis. Thus it is the general conclusion of this section that, in their present form, solar energy market diffusion models are closely akin to number mysticism. Their primary defect is their market penetration analyses, which are grounded on only a very simple behavioral theory. Thus the structure of the models themselves cannot be tested. Also because of this weak basis in behavioral theory, these analyses are limited to explaining behavior not predicting it. Finally, the one claim to legitimacy of these analyses is a foundation based on well developed models of diffusion processes. However, as was seen in the previous section, all the models except the GE model abandon this final claim to legitimacy by resorting to ad hoc models.

It is not a recommendation of this section that solar energy market penetration modeling be abandoned. Rather, it is recommended that standard diffusion models be used in their market penetration analyses. It would appear preferable that a model such as that of Bass (Ref. 6-2) which incorporates both innovation and imitation be used. This would at least place the analyses in a sound diffusion model framework so that their theoretical bases could be analyzed and compared. However, to establish reasonable confidence in the result of solar energy market penetration models, a market penetration analysis based on behavioral relationships must be developed. Admittedly, such a model will be complex and hence expensive to build and it would not be built, tested and available for some time. But building such a model is a prerequisite if solar energy market penetration modeling is to leave the realm of numerology.

SECTION VII

THE SOLAR RESOURCE: METHODS TO IMPROVE ITS ASSESSMENT

A. INSOLATION AS A RESOURCE

Many factors which influence the cost, demand, and availability of solar thermal power vary across regions. Solar development and market penetration strategies need to identify areas in which economic and environmental factors favor the use of solar power technologies over alternatives. Efforts could then focus on regions where the technology has the best chances of acceptance and success.

One of the most important variable factors is the solar resource itself. Efficient operation of solar thermal electricity-generating facilities requires maximum utilization of available insolation (incoming solar radiation), a resource that has temporal and spatial variations over the earth's surface. Existing data bases and analytical methods for evaluating these data bases may not be sufficient to permit utility and industrial users to assess the value of the resource. This section will summarize current solar resource assessments, and suggest areas toward which research might be directed to enhance the commercial potential of solar thermal electric facilities. (A glossary of technical terms contained in the text is presented at the end of the section).

1. The Nature of Solar Radiation

The sun, radiating electromagnetic energy at a black body temperature of nearly 6,000K, emits energy primarily within the range of 0.2-2.0 microns; it has an energy peak at 0.5 microns, which is the green portion of the visible spectrum. Nearly one-half of the sun's energy is emitted in near-infrared wavelengths. The electromagnetic energy travels through space and an infinitesimal fraction (on the order of one-two billionth) first strikes the outer limits of the earth's atmosphere, then interacts with the atmosphere and, eventually, the earth's surface in a multitude of ways. The implications of these interactions are currently under investigation by a number of scientists throughout the United States and elsewhere.

The amount of solar energy available for utilization is dependent upon a number of factors. The most fundamental is the variation in insolation resulting from variations in solar output. The accepted variation in solar output falls within three percent of the nominal value (Ref. 7-15). Thus, for systems definition and design solar output variation is considered as a minor perturbation with no major influence upon the resource assessment. For practical purposes, solar output can be considered a constant.

Insolation received at the earth's surface can be broken down into a number of component parts, not all of which can be used by solar thermal systems. The most important component, direct radiation, passes through the atmosphere with little attenuation (e.g., by absorption, reflection, and scattering). Direct radiation may be thought of as that which normally casts a well-defined shadow. Values of direct radiation are measured by pyrheliometer, an instrument adjusted so that the solar beam is normal to the instrument.

Many historical insolation data are of total hemispheric insolation (or total horizontal insolation); data values are measured by pyranometers, instruments set horizontal to the earth's surface. Thus, total insolation indicates energy received at any latitude without compensating for earth rotation or latitudinal position. These data are only marginally useful for solar resource assessment, at least in their original format. Total insolation data are used in agricultural and ecological studies (Ref. 7-2). In general, direct normal insolation exceeds total horizontal insolation throughout the country (Ref. 7-1). If the direct component of total horizontal radiation is subtracted from the total hemispheric insolation value, then a value of diffuse radiation is obtained. Diffuse radiation is scattered and is not useful to solar thermal facilities because it cannot be focused, as can direct insolation. In geographical areas having a large percentage of diffuse insolation, such as consistently cloudy environments, the efficiency of solar thermal facilities would be reduced.

2. The Geographic Availability of Insolation

The actual availability of insolation at the earth's surface varies as a function of earth-sun geometry and by interactions of the radiant beam with atmospheric constituents. The former factor is predictable and is temporally consistent, while the latter factor is susceptible to numerous major variations and perturbations, many of which are not well-understood.

Variations in insolation brought about because of geometric factors are primarily: (1) those resulting from orbital variations (seasonal), and (2) those resulting from tilt of the earth's axis (diurnal). Possibly even more fundamental is the relationship of receipt of solar energy on a sphere to that of a plane. Although the earth is a sphere, it appears as a flat surface to incoming parallel rays from the sun. The ratio of surface area on a sphere to a flat surface with the same radius is 4:1. Therefore, because sunlight is spread out over the earth's spherical surface, solar energy is effectively only one-fourth of its extraterrestrial value, when averaged over the entire earth's surface. Most radiant energy is received near equatorial latitudes where the sun's rays strike the earth nearly perpendicularly. For example, on the illuminated side of the Earth (50% of the surface area) nearly 50% of the solar energy falls on only about 14.5% of the earth's surface which is located near the equator. The remaining 50% of the solar energy is unevenly distributed over the remaining 35.5% of the earth's surface.

During the year the earth's distance from the sun varies by about 3×10^6 miles (4.8×10^6 km). When summer conditions exist in the northern hemisphere the earth is furthest from the sun (aphelion), nearly 94.5×10^6 miles away (152×10^6 km). The earth is nearest the sun (perihelion) in January when the distance from the sun is about 91.5×10^6 miles (147×10^6 km). Orbital ellipicity, then, serves to make northern hemisphere summers and winters slightly more mild than would otherwise occur. Consequently the greatest amount of extraterrestrial solar energy is received at the south pole during July.

More crucial are the variations in insolation brought about because of the 23.5° tilt of the earth's axis. If the axis was perpendicular to the plane of the ecliptic, all places on the earth's surface would have equal hours of day and night for each 24-hour rotation period. Because of the tilt, however, a substantial difference in hours of daylight occurs seasonally at different latitudes, especially in middle and high latitudes, although when averaged over the entire year the hours of day and night are equal everywhere. In high latitudes many hours of daylight in summer are followed by few hours of daylight in winter. Summer is not without its drawbacks, however, because in summer the angle of incidence is so large that considerable attenuation of the solar beam can occur (i.e., the ratio of direct to diffuse radiation is reduced). At very high latitudes the sun is barely above the horizon so that insolation must pass through many equivalent air masses (one air mass being the vertical distance from the earth's surface to the outer limits of the atmosphere, a zenith angle of zero). Considerable attenuation naturally occurs.

Many of these geometric relationships can be visualized in Figure 7-1, which presents sun-path diagrams for two latitudes, 32° N and 52° N, a distance of about 1,400 miles (2,253 km) for the 21st day of each month. The following data have been extrapolated from the graphs and indicate the variation in daylight hours for the summer and winter solstices (June 21 and December 21, respectively).

Date and Latitude	Time of Sunrise	Time of Sunset	Hours of Daylight (night)	Zenith Angle at Noon
21 June				
32°N	0500	1900	14 (10)	9 degrees
52°N	0345	2015	16 1/2(7 1/2)	29 degrees
21 December				
32°N	0700	1700	10 (14)	56 degrees
52°N	0845	1545	7 (17)	76 degrees

These data illustrate the large seasonal variations that occur at middle and high latitudes. Especially critical are the hours of daylight and the solar zenith angle at noon. In essence, at the summer solstice at 32° N the sun is nearly vertical at noon so that minimum attenuation occurs, at least on cloud-free days. At 62°N, however, the effectiveness of more hours of daylight is reduced because of the large zenith angle at noon. These relationships must be clearly understood in any system design and for identification of the first demonstration sites.

3. Terrestrial Complications

The geometric variations of insolation are easily described and necessary design modifications can accommodate them. Of greater concern are the many processes by which attenuation of the solar beam occurs for which fewer data exist. The following paragraphs indicate some possible complications that may require attention in the process of commercialization and represent significant issues that must be resolved as a prerequisite to commercial readiness of solar technology.

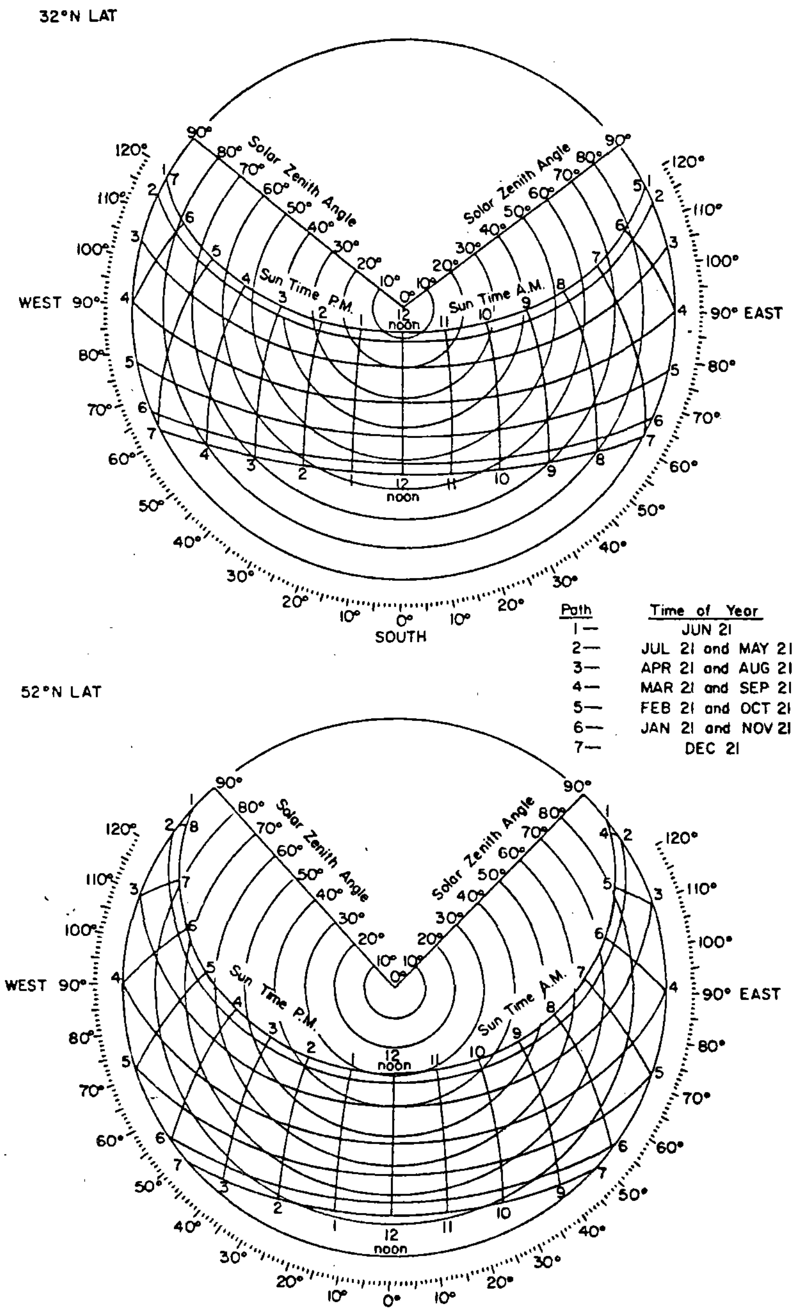


Figure 7-1. Sun Path Diagrams for Two Latitudes
(Source: Sellers, 1965, p. 17)

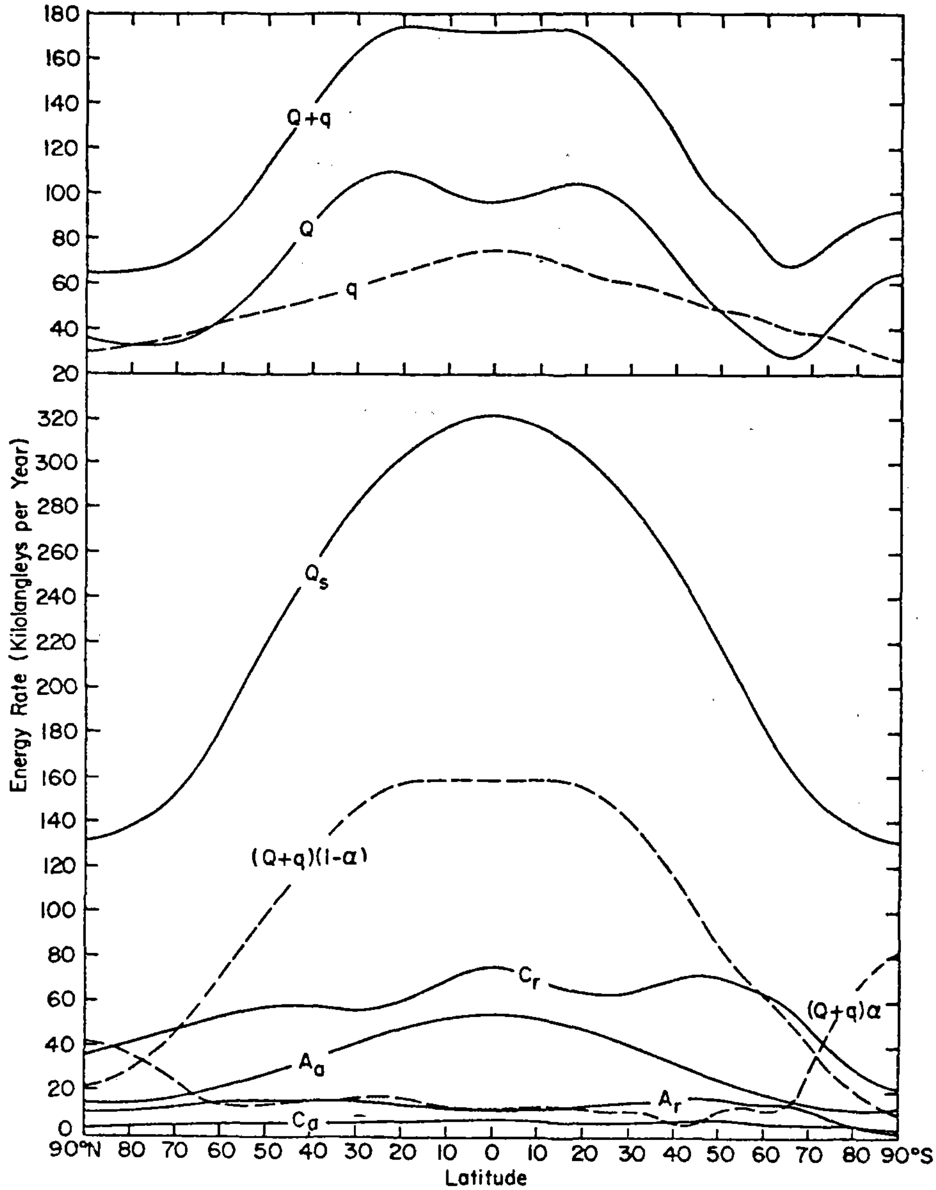
Micro- and meso-scale circulation patterns can have a significant impact upon deflation (pickup and transport) of surface material and the increased scattering of the solar beam that results (increasing the amount of diffuse radiation at the expense of direct radiation), and by presenting a hazard to the system itself (abrasion). These circulation patterns can be especially significant on a small scale because normal meteorological data do not identify them. As an example, the occurrence of dust devils in arid lands has certain spatial and temporal variations that are not well-understood, and for which no regular meteorological data are collected. Even so, dust devils can have a significant impact upon efficient operation of the solar thermal facility. Dust devils or sand storms represent one type of weather phenomenon that may hinder the commercialization of solar thermal facilities in semi-arid and arid environments.

Atmospheric constituents also have an important impact on diminution and attenuation of the solar beam. Of most concern, of course, is cloud cover which can transform all insolation into only a diffuse component. An analysis of the frequency and persistence of cloud families for candidate regions of commercialization will enhance the likelihood of solar thermal plants being adopted and operated efficiently. Cloud families are classified according to their height, thickness, and shape, and they tend to have spatial and temporal preferences; identification of these preferences should be a major component of site analysis. Some areas are consistently cloud-covered, while others have significant cloud cover only seasonally, if at all. Semi-arid and arid environments are not cloud-free. In fact, several arid areas have substantial cloud cover, if only intermittently during the day. Figure 7-2 presents the global distribution of insolation components, including absorptive and reflective components. The figure clearly indicates the relationship between major atmospheric attenuators.

Although the solar beam can pass through a clear atmosphere with little attenuation (excluding absorption of ultraviolet), a highly transparent or clear atmosphere is seldom present. Dust, water vapor, other particulates or aerosols scatter and otherwise attenuate the beam. Water vapor is less important in attenuating the solar beam than it is as a major absorber of heat energy re-radiated from the earth to the atmosphere and space (the greenhouse effect). In areas that have large amounts of water vapor in the atmosphere, this increased heating from water vapor absorption can result in atmospheric instability and the formation of extensive cloud cover and/or convectional storms.

Recent research of solar beam attenuation indicates that of far greater importance than water vapor is the presence of aerosols, many of which are anthropogenetic (Ref. 7-6), that is, man-made. Identification of aerosol sources and an evaluation of their persistence in the troposphere and stratosphere, if possible, may provide a significant input to system design and site selection activities.

Atmospheric transmissivity can also be degraded through cultural activities, many having a strong regional focus. Land-use practices can diminish the quality and quantity of the solar resource (such as agricultural or industrial activities). Items that merit examination in the commercialization process for solar thermal plants include insolation variations between rural and urban locations, especially fugitive dust impact in the troposphere associated with agricultural activities. If one goal of



KEY:

Q_s: EXTRA TERRESTRIAL RADIATION FROM SUN

Q: DIRECT RADIATION

q: DIFFUSE RADIATION

α: ALBEDO

Ca, Aa: CLOUD AND ATMOSPHERIC ABSORPTION

Ar. Cr: ATMOSPHERIC AND CLOUD REFLECTION

(TERMS EXPLAINED IN GLOSSARY)

Figure 7-2. Average Annual Distribution of Solar Radiation Disposition in the Earth-Atmosphere System (Source: Sellers, 1965, p. 22) the solar thermal program is to provide electricity to areas that would not otherwise have a readily available and consistent energy source, an evaluation of the role of dust and its persistence in those regions selected for demonstrations should be undertaken. It is also known that urban environments can greatly modify the thermal resource; what is less well-known is how urban environments modify insolation through an increase in localized atmospheric pollutants. Moving only a short distance from these areas may result in an insolation resource that can be considerably different, thereby affecting siting decisions. In addition, data recorded in an urban environment may poorly reflect rural conditions, or vice versa. In effect, land-use practices and their role in altering the solar resource should be incorporated into the site selection process.

The many combinations of weather elements (insolation, temperature, precipitation, wind, etc.) that exist in nature, of which only a few examples were given in the preceeding paragraphs, can be grouped into representative climatic types, similar to what is currently being attempted for insolation resource regionalization tasks at many laboratories. A climate map synthesizes all dominant weather elements in an area, and thus may be useful in evaluating regions for solar thermal site selection. In addition to analysis of a detailed climate map, analysis of a vegetation map is useful, if both are analyzed in conjunction with available insolation data. Because vegetation is the single best expression of climate, a map of vegetation may allow us to more fully interpolate into areas in which insolation data are lacking. A gleaning of the most widely accepted vegetation map to date (Ref. 7-8), reveals many similarities between vegetation patterns and insolation patterns, even at the gross scale of the latter. This type of surrogate analysis may provide some of the desired information not otherwise obtainable, at least without considerable expenditure of resources.

One topic that has received little analysis is that of weather variations within different climatic types. Long-term variations in climate have been analyzed, but short-term (yearly) variations have not seen intensive investigations, yet it is the short-term variation that may have some of the greatest impacts on the viability of solar thermal stations. Most individuals consider a semi-arid or arid environment as being stable, yet these areas experience some of the largest weather variations of any place on the earth's surface. Unfortunately, little is known about the magnitude of these weather variations.

There is one primary reason for lack of understanding of weather variations in dry climates. Until recently there had not been much interest in arid lands; they were not analyzed very intensely, and therefore the data bank for arid lands is poor. Comparatively few meteorological recording stations are located in the sparsely populated areas of the desert or semi-deserts, yet variability of weather patterns here could conceivably be an important criterion in selecting sites for demonstration of solar thermal facilities. For example, precipitation variability is often an order of magnitude greater in arid environments than in humid ones. Of particular concern is the occurrence of high-intensity flash floods which could result in system damage. The frequency distribution of these storms has certain geographic preferences that can be identified and assessed.

4. The Technological Availability of Insolation

The variabilities noted above, and others not described, can be critical inputs to final system design. Here, collaboration with system designers should be maximized. The ranking of the variabilities of the different weather elements, and the temporal and spatial evaluation of the solar resource will help determine final system efficiency over the life cycle of the plant.

Insolation data must be collected by some means in order to be used. At the present time collector developments fall into broad categories: fixed and tracking; flat plate and concentrating. Fixed collectors are constructed so that maximum receipt of insolation normally occurs without daily re-orientation of the collector. Thus, insolation collected is not maximized throughout the day. Tracking collectors are motor driven and continually focus (if a concentrator) on the solar disk, thereby maximizing the receipt of insolation during the day. Because of the relationship of earth-sun geometry, fixed-plate collectors would not work as efficiently in high latitudes as tracking collectors.

As noted in Section II, tracking collectors come in a variety of specific types, and are designed to follow the sun throughout the day; one-axis or two-axis collectors may be used. The selection of one axis over two axis will, in part, be determined by both the availability of the resource and the geographic location of the specific site. The greater the latitude, the more likely two-axis tracking will be required.

Flat-plate collectors have the same insolation absorbing area as the area which intercepts the insolation. Concentrating collectors, however, use optical techniques to focus the insolation falling on the absorbing area to a much smaller area, thereby increasing the energy flux. Flat-plate collectors are usually designed for applications requiring energy delivery at relatively moderate temperatures, on the order of 100° C above ambient temperatures (Ref. 7-4). Flat-plate collectors can use diffuse and direct radiation and therefore they are not used in solar thermal systems where high temperatures are required.

In comparison with flat-plate collectors, concentrating collectors focus energy to a point and the greater energy flux results in high temperatures, a necessity for most solar thermal applications. Because concentration of insolation is required to obtain high temperatures, only the direct component of insolation can be used. That is, only direct beam radiation can be focused, the diffuse component is ineffective. Thus, the selection of collector type is very dependent upon geographic location and physical geography of an area. Site selection criteria and collector choice can cause a system to operate in less than an optimal manner.

The complexities associated with collector selection and regional climatic variations are indicated in Figure 7-3. These diagrams were selected from the Agroclimatic Atlas of the World (Agroklimaticheskie Atlas Mira, Moscow, 1972), and show the relationship of diffuse to direct radiation at two very different sites within the Soviet Union: Dickson (73° N) and Tashkent (41° N). The former station is located along the Arctic coast in central Siberia, while the latter is a desert station in Soviet Central Asia. The two diagrams are markedly different, and illustrate the point that arid lands

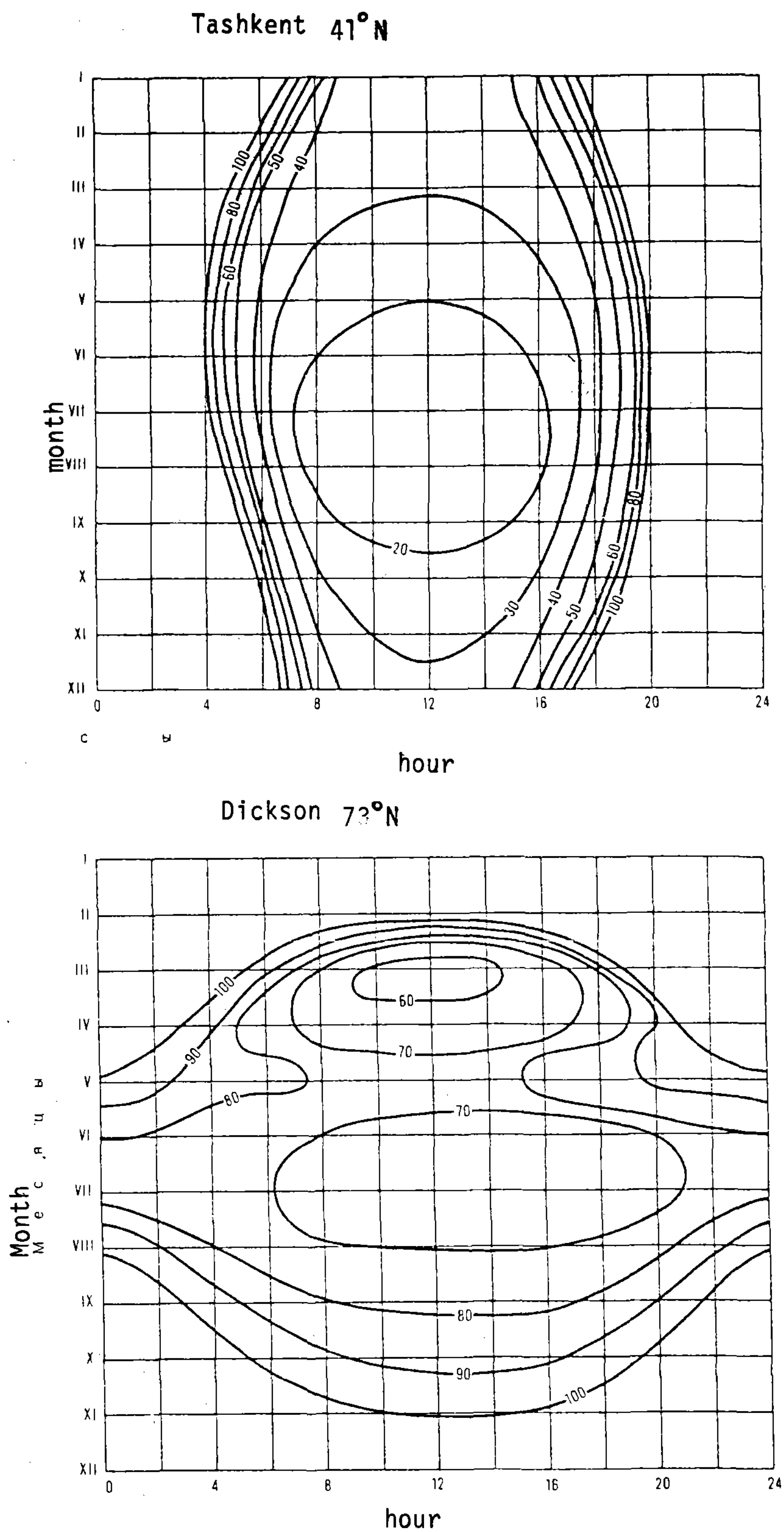


Figure 7-3. Daily Course of Diffuse to Total Radiation at Two Sites (Source: Agroklimatichiskii Atlas Mira, Moscow, 1972)

characteristically have much less partitioning of the solar beam. For example, at 1200 hours in mid-June less than 20% of the insolation is diffuse at Tashkent while at Dickson, at the same time, between 60% and 70% of the insolation received is diffuse. In fact, at Dickson there is never as much as 50% direct insolation. Dickson's high latitudinal position is shown on the diagram. During January and December and for much of February and November the sun is barely above the horizon, resulting in nearly all of the insolation being diffuse. Thus, great care must be exercised in selecting the most appropriate collectors for large-scale application of solar thermal facilities.

B. INSOLATION DATA FOR PREDICTING REGIONAL DISTRIBUTIONS

The discussion in the previous subsection was intended to emphasize that many seldom considered elements can reduce the efficiency of solar thermal facilities and thereby reduce the rate of acceptance. It is imperative that efforts be directed toward evaluation of current insolation data, and also toward evaluation of those elements that may result in localized diminution of insolation, when existing data are considered representative of a much larger area.

1. Status and Assessment of Existing Actinometric Network

The existing actinometric network is sufficient for only approximating regional components of insolation. The primary network in the United States consists of a number of stations that have had their historical hourly data rehabilitated, although other stations record daily data. Even as late as January, 1978, only five official NOAA (see glossary) stations recorded hourly direct-normal insolation. Those stations that record global insolation do not necessarily record direct or diffuse insolation; in fact, generally they do not. Prior to the 1970's little attention was given to insolation measurements, except for agricultural studies; in those studies, the desired data were total horizontal insolation. One of the biggest problems with the current data base is the suite of uncertainties and errors within the data. Models have been, and currently are being, developed to account for these errors and uncertainties.

Figure 7-4 shows the distribution of the actinometric network. As can be seen, gaps exist in the network coverage, especially when one considers the variations that develop because of terrestrial factors noted in the preceding discussion.

Although the most important insolation component for solar thermal facilities is direct radiation, few stations record it. Models are available that partition total horizontal radiation into direct and diffuse components, but the accuracy of the results is questionable, and at best is within 10%-20% of actual levels. Many historical data now being analyzed were recorded with instruments that were out of calibration or close to inoperable.

Many stations are located at sites where the recorded insolation data can not be expected to represent conditions of nearby areas. Topographic, and therefore weather, factors significantly alter the insolation resource. The best use of the existing network is to determine regional patterns of

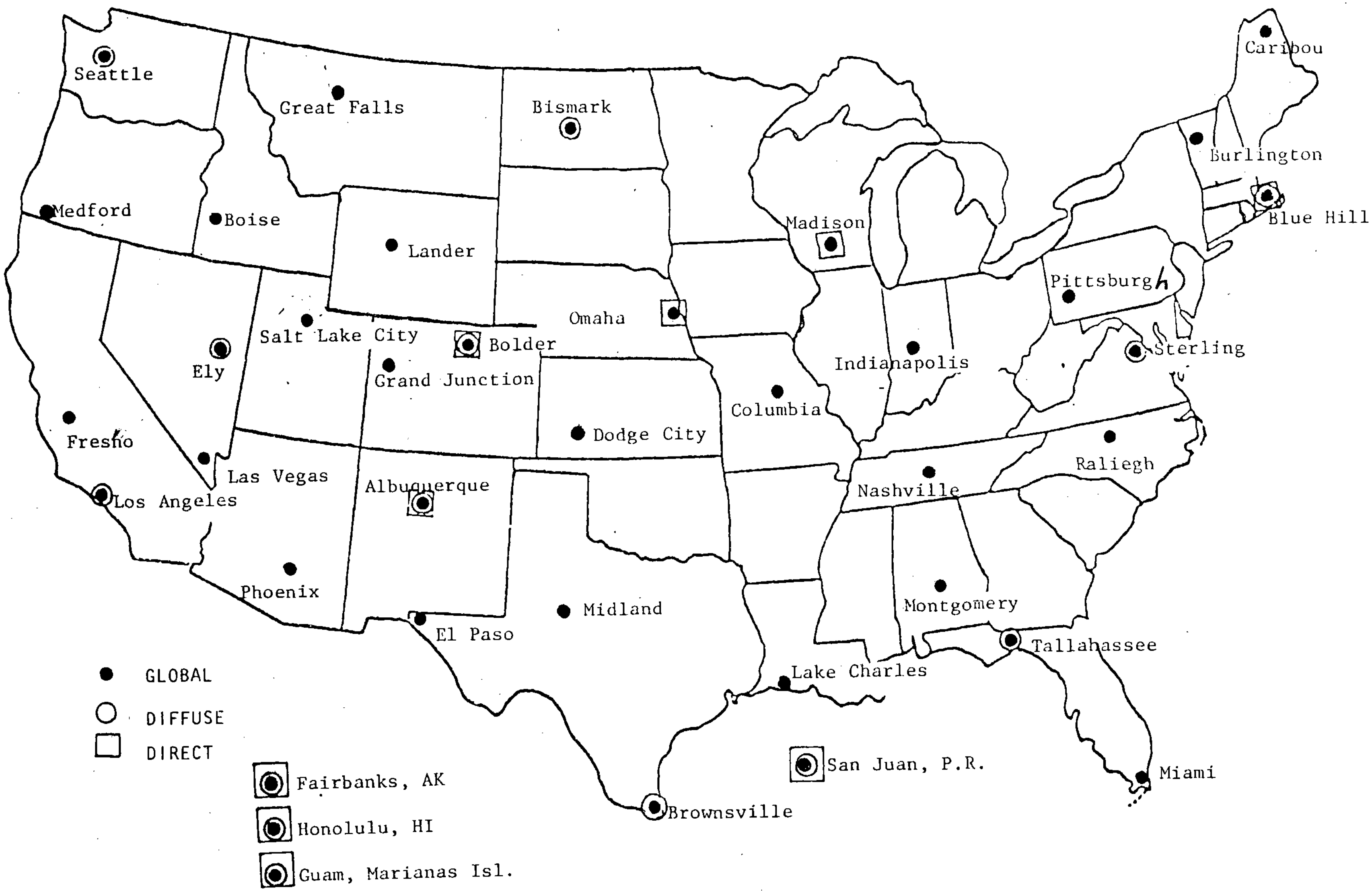


Figure 7-4. Existing Actinometric Network

insolation distributions, at least on a gross basis. Thus, a major 'first-cut' effort would attempt to more specifically regionalize the country, providing an important input to the site selection task. Budgetary and staffing considerations preclude the likelihood of significant increased network expansion, although NOAA anticipates upgrading some standard meteorological stations to include more radiation and other specific measurements, such as carbon dioxide (Ref. 7-9). By the end of 1979, approximately thirty stations will have recorded direct-normal insolation for an entire year.

2. Representative Models

A number of models are available to evaluate and predict insolation, but none is applicable for all solar energy applications. This brief discussion is intended only to illustrate the variety of models currently used and not to suggest a preference, because each has certain advantages. Some of the more popular models are those developed by Liu and Jordan, Temps and Coulson, and Klucher (Ref. 7-7). In addition to these are the numerous models developed under the auspices of NOAA, at national laboratories and in private industry. These would include, for example: Total-Horizontal Solar Radiation Model, Direct-Normal Solar Radiation Model, and the Aerospace Corp.'s Insolation Data Model.

Liu and Jordan's original work is often considered the starting point for development of more complex models. Liu and Jordan's first model attempts to determine total insolation received by a tilted surface. Input data are hourly average values of insolation. Evaluation of the model indicates that it underestimates the quantity of insolation by up to 10% (Ref. 7-7). The method of Coulson and Temps, which is also a clear-sky model, is considered by Klucher to be deficient, primarily during cloudy conditions. Klucher notes that Liu and Jordan's model works reasonably well during overcast conditions, while Coulson and Temps' model works reasonably well only under clear-sky conditions. Klucher followed up on these models and developed one that modulated the Coulson and Temps' model so that data for overcast conditions could be predicted. The predicted values correlate well with measured values (usually within 3%). The model, however, predicts total insolation; thus, its usefulness is directed to photovoltaic applications. Partitioning into the direct and diffuse components is still necessary.

Of particular interest in determination of the partition of insolation is the on-going work of Randall at the Aerospace Corporation. The algorithm model was developed to improve estimates of hourly direct-normal insolation for 26 stations with total hemispheric data selected by NOAA for correction (Ref. 7-10). This type of model development can be compared with the work being performed by Northrup Services to provide much valuable insolation information. Northrup has undertaken a study that attempts to determine just how large an area can be considered representative of point source data from the SOLMET (see glossary) stations.

Any model will have some drawback for a particular purpose, although sufficient models appear to exist for approximating basic insolation availability. Because commercialization requires identification of the best sites, or at least identifying what shortcomings exist in the solar resource base at a chosen site, it will be necessary to instrument the sites selected for demonstrations. Instrumentation should occur after evaluation of the information provided by existing models and surrogate data, so that only a minimum of area will require detailed instrumentation and analyses.

C. RESEARCH GOALS

1. Program Plan

In order to develop a condition of commercial readiness of solar resource technology, it is desirable to perform the tasks below. These tasks will complement existing solar resource assessments. Essentially the tasks can be summarized by stating their goals.

a. Acquisition of appropriate data

- a more complete understanding of seasonal variations in insolation
- a more complete understanding of diurnal variations in insolation
- modify models or develop techniques to more fully fill in data base gaps resulting from the sparse actinometric network.

b. Regionalization

- critically compare selected urban/rural sites to determine local variations in solar resource availability as a result of land-use practices.
- coordinate with institutes currently involved in the identification and evaluation of aerosol persistence in the troposphere.
- analyze short-term weather variations within the major climatic types in order to determine significant weather processes that may hinder efficient operation of solar thermal systems.

c. Instrumentation

- instrument sites selected for the first demonstration experiments in order to obtain optimum insolation data for use in analysis of system performance.

2. Approach

To attain these goals requires continued evaluation of existing data and models, and possible refinement of them. Also required are improvements in regionalization methods, including instrumentation of demonstration sites. Specifically, an assessment of weather variability patterns in the country will more fully allow evaluation of the availability of insolation in an area larger than a specific site. As previously indicated, examination of weather variability is especially critical in semi-arid and arid regions because of their probable selection as initial commercialization experiment sites.

Weather element variability can be exceedingly high in these regions (Ref. 7-5) and not well-understood spatially. Instrumentation of specific sites will not only give the system analyst the best possible data with which to work, but will also provide data for the regionalization task.

Existing meteorological and topographical data, and data obtained by satellite platforms (e.g., SMS-2, LANDSAT, NOAA-5), can overcome some data paucity problems in arid lands, a situation noted previously. Existing meteorological and satellite data can allow for a reasonable assessment of cloud development (frequency and persistence) in the country and thereby help to minimize the likelihood of less-than-desirable site selection. An example of the type of analysis needed is presented in Figure 7-5. The two photographs were taken on the same day in mid-summer, one in mid-morning and the other in mid-afternoon. The development of cloud-cover and convectional storm activity has definite spatial characteristics that can and should be evaluated.

As Figure 7-6 illustrates, the current scale of extrapolation of the solar resource (e.g., direct-normal) will not allow anything more than a first order approximation for candidate site selection commercialization. Improvements are required.

3. Recommendations and Conclusions

For the short-term, analytical techniques need to be developed to address the problem of data paucity. This problem can be attacked by immediately initiating a comprehensive examination of weather variability in major climatic regions. The result of this investigation will provide input data to solar resource regionalization tasks that are currently underway at a number of institutions. Part of this examination should be a critical comparison of the local variations in solar resource availability resulting from land-use practices, especially those variations that exist between rural and urban areas.

These initial analyses will continue over the long-term but their initial results will allow for a first-cut selection of candidate demonstration sites. Instrumentation of the site(s) selected will then give the system analyst the best available data for use in determining the efficiency of the system at a site that should be representative of a larger geographical area. Application of various models that predict insolation will enhance both the regionalization and instrumentation tasks. Instrumentation, in particular, will be used to help verify the accuracy of the various models. Of critical concern is the applicability of any model to the physiographically diverse western portion of the country: an area where local effects can greatly alter weather, and therefore, insolation patterns.

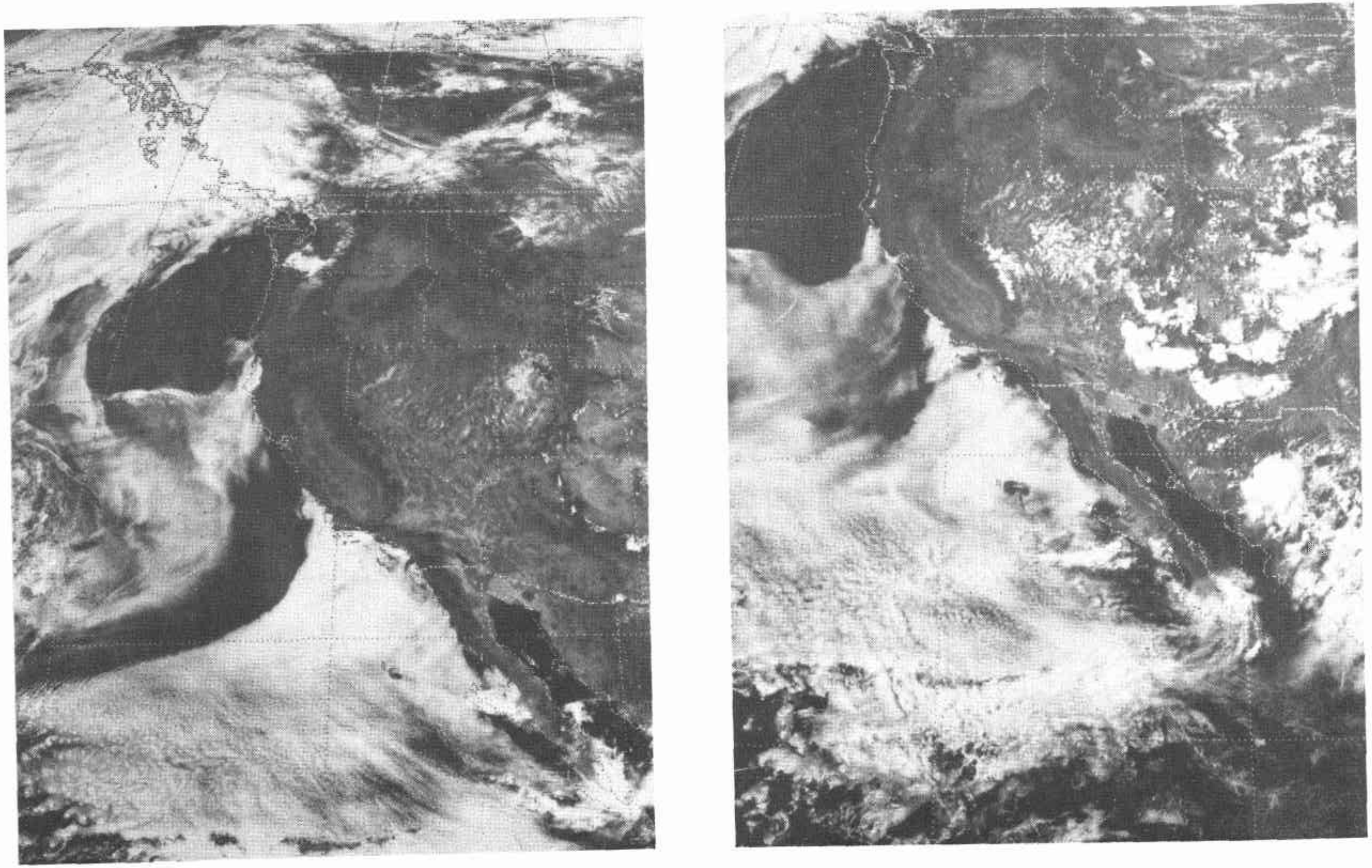


Figure 7-5. SMS-2 Images of the Western United States for Morning (left image) and Afternoon (right image) of 25 July 1975

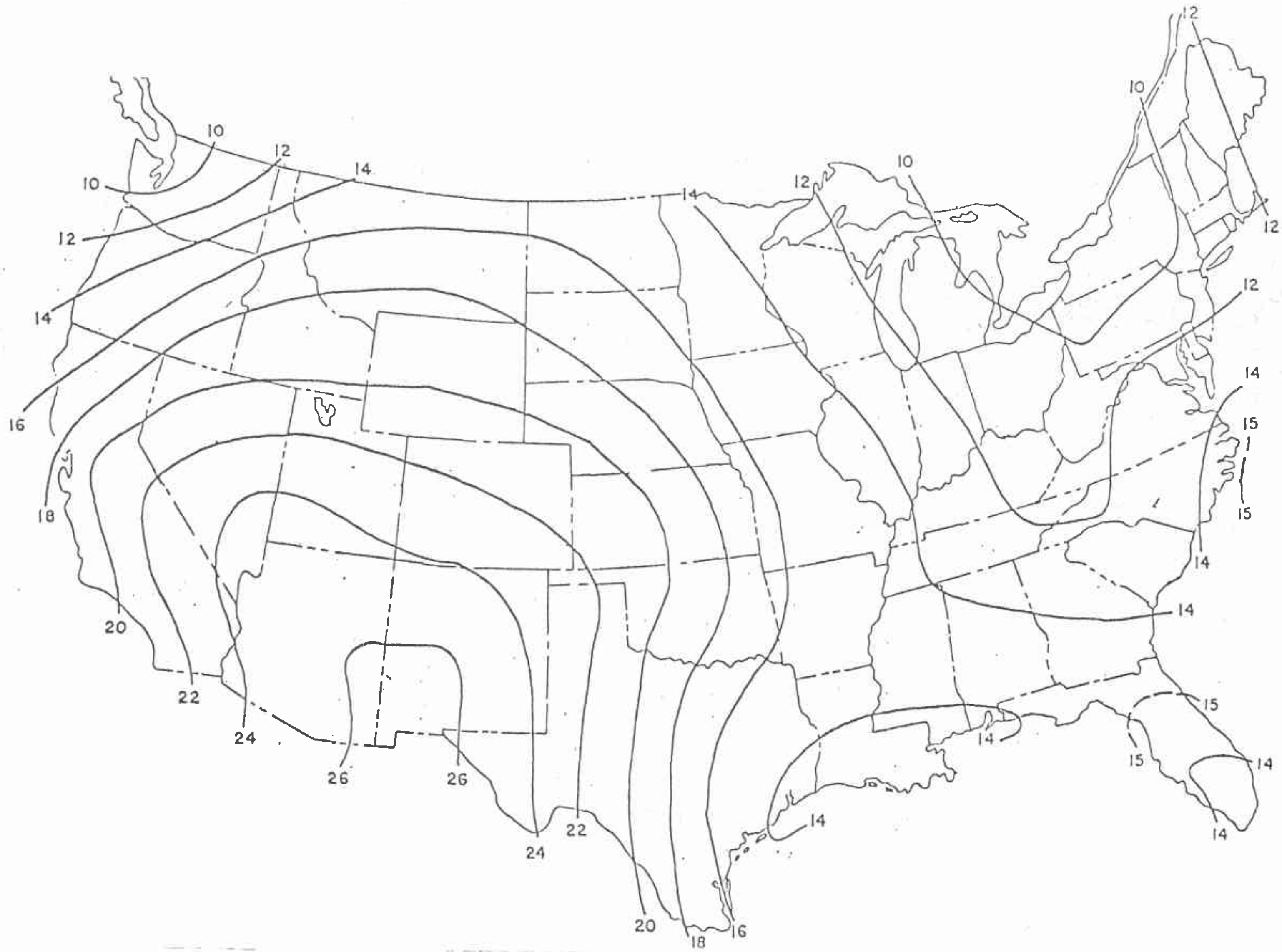


Figure 7-6. Mean Daily Direct Solar Radiation (Annual)
Megajoules per Square Meter
Source: Air Resources Laboratory

GLOSSARY

actinometric network
: network of stations that have instruments capable of measuring solar energy

albedo
: amount of energy reflected, usually expressed as the percentage of total energy incident on a surface that is reflected

deflation
: the picking up and transportation of material by wind action

diurnal
: daily changes

insolation disposition:

a	albedo
A_a	absorption by the atmosphere
A_r	reflection by the atmosphere
C_a	absorption by cloud
C_r	reflection by cloud
q	diffuse component of insolation
Q	direct component of insolation
Q_s	extraterrestrial insolation

NOAA
: National Oceanic and Atmospheric Administration (Department of Commerce)

SMS
: Synchronous Meteorological Satellite

SOLMET
: Insolation and meteorological data tapes made available by the National Climatic Center

solstice
: day of the year when vertical rays of the sun strike the earth at their maximum poleward latitude in each hemisphere

zenith angle
: angle between vertical and object (e.g.,sun)

SECTION VIII

CONCLUSIONS AND RECOMMENDATIONS

Because of the rapid changes in fuel prices and availability, energy users have undertaken a search for alternatives. Solar thermal power is one possible alternative, but it faces a series of technological, economic, and environmental problems which must be resolved before it is a viable, competitive alternative. These problems were addressed in a variety of ways throughout this document. They have been grouped into several broad categories below, each of which includes analysis and conclusions drawn from the report, as well as recommendations for resolving the issues raised.

A. REGIONAL CONSIDERATIONS

Many of the factors influencing the market potential of solar power vary in their spatial distribution. If the use of solar thermal capability will first occur in areas where these factors favor solar energy, then there is a need to identify these factors.

One of the most important factors is the variability of the solar resource itself. As Section VII emphasizes, insolation varies with the season, local weather conditions, latitude, degree of urbanization, presence of pollutants, and land use factors. There is an immediate need for better understanding of these insolation changes. Section VII recommends that basic research be undertaken to improve understanding of seasonal and daily variations in solar availability, so that solar thermal systems may be located more efficiently. The data gaps in the insolation measurement network should be filled by upgrading individual stations or expanding the coverage of the network. Research should also include a study of variations in urban and rural insolation, an identification of pollution sources and their persistence in the atmosphere, and a study of weather variations across climatic types. This research will result in more reliable insolation data and a better basis from which to make system siting decisions.

Other local factors affect the competitive potential of solar thermal power within each region. These include variations in the distribution of fossil fuels, in the costs of labor and employment patterns, in electricity rate structures and delivery costs, in population concentrations and demand load profiles, in environmental side effects, and in land use requirements. Each of these factors affects solar thermal power competitiveness. Future research should attempt to list all of these critical factors, obtain reliable and consistent data on them, and portray the geography of each factor. In this manner, it will be possible to identify those areas with the greatest potential as solar thermal power users, and to determine which regions and sectors will be subject to the greatest impacts of solar thermal power development.

B. THE SOLAR TECHNOLOGY

There are many problems associated with the design, cost, and acquisition of solar thermal power systems. One of the most immediate problems is development of the solar thermal technology itself. As Sections II and III note, improvements in conversion efficiency could reduce collector area, with consequent reductions in capital costs and land use requirements. To allocate limited R&D resources more effectively, there may soon be a need to select an optimal system (or set of most promising systems) upon which to focus research efforts; even the choice of criteria to be included in this selection process will be an important decision.

A second major problem with solar thermal systems is their relatively high capital costs; cost reduction will be one of the most decisive factors in determining solar thermal viability. Section III outlines those subsystems with the greatest potential for cost reduction. Although potential does not guarantee cost reduction, and cost reductions do not guarantee competitiveness, design research which emphasizes cost reduction may promote solar thermal power's competitive viability.

However, final purchasing decisions depend on a number of factors, including alternative energy costs, market expectations, regulations, tax incentives, and ownership arrangements. Section V develops a methodology to quantify the life-cycle cost patterns of solar thermal technologies, and to compare these costs to available alternatives. These computer quantifications help to sort out system costs, but there is still a need to determine the uncertainties involved before optimal systems are chosen and commercialization efforts begin.

C. THE MARKET FOR SOLAR POWER

Even if solar thermal technologies are well designed and have costs similar to alternatives, these do not guarantee that solar thermal systems will acquire a significant share of energy demand. Demand share depends on many other factors; three of these are market factors, financial factors, and management problems.

Market factors include the price of competing technologies, as well as general economic conditions; one of the major competing alternatives is electricity. Much research still needs to be done on the potential interactions between utilities and solar thermal power, and on the rate structures utilities will be allowed to use. Section IV notes that studies should be undertaken in the following areas: how utilities choose their rate base; which rate structures (declining block rates, peak-load pricing, etc.) allocate resources most effectively, and which structures are easiest to administer; whether electricity supply is elastic enough (and electricity demand is inelastic enough) to justify the current utility practice of passing increased costs of electricity production on to the consumer; and whether there is some pricing mechanism or metering hardware (such as use of microprocessors) which would allow electricity supply and demand to interact, rather than requiring utilities to have enough capacity to meet any and all demands.

Financial factors and ownership arrangements also change the relative price of solar power to users. Sections IV and V noted that subsidies and ownership conditions can have profound effects on the investment decisions users make; more research needs to be done on the magnitude of these effects.

Finally, management of solar thermal technologies can be important; poor timing when introducing a new power system can decrease the system's market acceptance. To counter this problem of mistiming, many firms rely on market penetration analysis to forecast production needs. But Section VI pointed out that these penetration models cannot forecast very well; market penetration estimates depend strongly upon the assumptions made, and these assumptions have not tended to be particularly valid. Thus, there is an immediate need for better forecasting tools; some of these market forecasts might be based on current econometric models and an analysis of buyer behavior. It would then be easier to develop solar thermal systems which can meet these demands in an optimal manner.

D. FEDERAL INVOLVEMENT IN SOLAR ENERGY

If there are additional social benefits to solar thermal usage which are not reflected in the private market for energy, then there may be some justification for government involvement in solar power development. Thus, one of the first areas of research necessary for better federal interaction with the market process is an analysis of which stages of solar thermal development are best handled by the private commercial process, and for which areas economic forces alone do not yield an optimal solution.

Having identified areas where government involvement is appropriate, federal agencies can then begin to carefully define the imperfections which exist and policy tools to mitigate these problems within each area. Studies should attempt to estimate how large the market imperfections are, and what policies or incentives would overcome these imperfections with the least disruption of economic activities. Thus, there is a need to measure how the impacts of incentives vary with the form of solar thermal power ownership, and how each incentive affects user costs and investment.

Much thought must go into the criteria government agencies use for decision-making purposes. For example, what criteria will be used in siting decisions? In deciding insolation rights? Will rate structure decisions be based on average or marginal costs? What alternative fuel use scenarios will solar energy choices be based on? These questions must be carefully considered to avoid arbitrary decisions.

Finally, some inquiry should be made into the problems government regulation and intervention cause in the marketplace. Studies should attempt to measure the costs energy regulations impose on society, and whether these regulations are worth the cost. Two examples of regulatory problems which solar thermal power may face are the questions involved in cogeneration rules and hybridization issues. First, will the ownership of solar cogeneration facilities with "buy back" agreements (utilities must purchase surplus solar generation at a given price) subject solar power owners to the same regulations that utilities face? Secondly, hybrids (solar power systems with fossil fuel backup) may be the most efficient use of energy resources; how costly are regulations which forbid the construction of new power plants using natural gas as a backup fuel? These are just two examples of cases where regulation could lead to a less-than-optimal solution. Federal involvement should be reviewed in light of the problems it can create.

E. SOCIAL IMPACTS

There are many impacts of solar thermal power usage which are difficult to measure in dollar amounts, but important nevertheless. One of these impacts is environmental: solar power systems require large amounts of land, and are expected to operate near residential areas and in high insolation areas; solar power may therefore compete for scarce urban real estate or prime agricultural land. Solar thermal systems are also among the most capital-intensive forms of energy; there has been no comprehensive study of how large demands for solar capital (especially if accelerated by substantial incentives) will affect interest rates, real estate prices, housing markets, and investment in other projects. Finally, there has been little research on how additions to solar capacity affect employment or employment patterns, or on the safety problems involved with solar thermal systems.

F. UNCERTAINTY

Uncertainty is the least measurable and most pervasive factor in solar thermal power development; it appears in the technology, costs, market demand estimates, environmental impacts, regulations, and future alternatives. Actions which could measure or reduce uncertainty would greatly assist solar power's viability. Basic research would include an analysis of the uncertainties which present the largest barriers to solar thermal power development, and a description of actions which most effectively resolve these uncertainties. Some means of expressing variability in system factors (price, reliability, etc.) so as to reflect uncertainty should also be developed. Since market uncertainty is a prime factor in hampering private investment in solar power, improved market forecasting tools might alleviate this problem.

Many complex issues still remain in the development of solar thermal power. These issues must be resolved before solar power becomes a widely used energy alternative. This report has listed some of the more pressing research needs; investigations of these problems will greatly assist the technological and commercial viability of solar thermal energy.

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