Solar Thermal Power Systems

Summary Report

MASTER

June 1980

Prepared for:

U.S. Department of Energy

Assistant Secretary for Conservation and Solar Energy

Division of Solar Thermal Energy Systems

Washington, D.C. 20585

Under Contract No. DE-AI01-79ET21036

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The Aerospace Corporation

El Segundo, California 90245

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FOREWORD

This report summarizes the work accomplished by The Aerospace Corporation from April 1973 through November 1979 in the mission analysis of solar thermal power systems. Sponsorship of this effort was initiated by the National Science Foundation, continued by the Energy Research and Development Administration, and most recently directed by the United States Department of Energy, Division of Solar Thermal Systems.

Major findings and conclusions are summarized for large power systems, small power systems, solar total energy systems, and solar irrigation systems, as well as special studies in the areas of energy storage, industrial process heat, and solar fuels and chemicals. The report describes the various data bases and computer programs utilized in these studies, and tables are provided listing financial and solar cost assumptions for each study. An extensive bibliography is included to facilitate review of specific study results and methodology.

The report was prepared by Leon R. Bush, who also directed the analysis of the solar total energy studies. The author is grateful to the many project engineers who conducted the various studies and reviewed the report content, and especially to Dr. Mason Watson, Director of the Energy Systems Group, who directed Aerospace's efforts in all of the solar thermal systems studies, and provided invaluable advice and guidance during the report preparation. The assistance of Fred Eggers in figure preparation, and Pat Dunn and Ellen Flannery in the typing and editing of the report is also gratefully acknowledged.

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I. INTRODUCTION

A. PURPOSE AND SCOPE

Since 1973, The Aerospace Corporation has supported the National Solar Energy Program through a series of mission analysis studies of solar thermal power systems. The goals of these studies were as follows:

- Formulate methodologies for evaluating alternative solar energy concepts
- Assess the technical and economic feasibility of various solar thermal energy concepts and applications and identify those having the greatest potential
- Establish technical and economic bounds for solar energy systems, subsystems, and major component design and performance parameters for selected applications
- Determine the potential market size and assess the resource, environmental, and institutional impacts of a significant market penetration by solar thermal conversion systems.

The purpose of this report is to provide the Department of Energy Staff, potential solar energy users, and other interested organizations with a summary of the methodology, assumptions, and major findings of these studies. Extensive references are provided to permit the reader to pursue detailed technical results and determine the content and availability of computer programs and data bases generated in the course of these studies. The report is limited in scope to Aerospace mission analysis in support of the Solar Thermal Program efforts. The DOE Program Summary¹ should be consulted regarding solar thermal power systems studies by other contractors. The report excludes Aerospace program field support efforts for DOE (Ft. Hood, Barstow, etc.) and other solar, non-thermal mission analysis activities (photovoltaic, OTEC).

¹Solar Thermal Power Systems Program Summary, DOE Report DOE/CS-0145 dated December 1979.

B. CHRONOLOGY

A history of Aerospace's solar thermal studies is shown in Table I-1, starting with the National Science Foundation's sponsorship of Solar Large Power Systems studies in April of 1973. The initial study included conceptual design and costing of a single trough collector configuration for the Southern California region. The next study was expanded in scope to include configuration tradeoffs and the Southwest region. Subsequent studies examined large power applications on a national basis, and addressed such issues as advanced technology, repowering, and societal impacts. Sponsorship of the study effort was transferred from NSF to ERDA in January 1975, and transferred again to DOE in October 1977 when the latter became the lead federal agency for the Solar Thermal Program. Beginning in May 1977, a comprehensive series of studies was initiated to evaluate small solar systems for power, total energy, and irrigation (pumping) applications, using many of the techniques and data bases established during the large power studies. Special studies were also initiated in the areas of thermal storage, high-temperature industrial process heat, and solar fuels and chemicals.

Depending on the specific study objectives, the above studies generally contained one or more of the following elements:

- Simulation - Usually an hour-by-hour evaluation of solar system performance, using hourly demand and insolation data as inputs.
- Configuration Tradeoffs - Comparison of the relative energy conversion efficiency and capital costs of different solar power plant designs.
- Economic Evaluation - Relative busbar energy costs of solar vs. conventional power plants for different demand requirements and plant locations.
- Market Potential - The aggregate energy or fuel which theoretically could be displaced by a given solar technology in a particular market, based on land availability, market growth, and solar capacity.

Table I-1. Chronology of Aerospace Solar Thermal System Studies

- Market Penetration - Expected aggregate energy or fuel displacement, based on favorable solar economics relative to conventional systems.
- Survey/Validation - Interviews with potential solar system users to confirm qualitative and quantitative criteria used in developing market potential and penetration estimates.

Table I-2 shows which of these elements were addressed in Aerospace's solar thermal study efforts. Rationale and recommendations for further study are discussed in Section II.C of this report.

C. REPORT CONTENT

The report is divided into two major sections and two appendices. Section II, Summary, presents the results of the mission analysis studies in terms of potential and expected fossil energy displacement at a national level by the year 2000. Major findings and conclusions are then listed for each of twelve studies, and the section concludes with a discussion of areas of future study effort. Section III, Detailed Study Results, provides a more complete description of each study, including methodology, input assumptions, and study results. An extensive list of references is provided at the end of this section.

Appendix A lists the 13 data bases and 12 computer programs developed and utilized in Aerospace's mission analysis effort. A brief description is provided for each, together with a listing of availability, pertinent references, and particular studies in which they were utilized. A summary of the types of data bases and programs included is shown in the table below:

Table I-2. Study Content of Aerospace Solar Thermal Mission Analysis

STUDY	STUDY PHASE					
	SIMULATION	CONFIGURATION TRADEOFFS	ECONOMIC EVALUATION	MARKET POTENTIAL	MARKET PENETRATION	SURVEY/ VALIDATION
LARGE POWER						
TOTAL ENERGY						
SMALL POWER						
IRRIGATION						
ADVANCED SYS						
HI-TEMP IFH

Performed by The Aerospace Corporation

<u>CATEGORY</u>	<u>TYPE</u>	<u>NUMBER</u>
Data Bases	Demand	4
	Insolation	5
	Market and Energy Price	4
Programs	Demand Forecasting	2
	Performance Simulation	2
	Utility Interface Model	2
	Utility Financial Model	2
	Market Potential/Penetration	4

Appendix B presents an overview of the economics methodologies utilized in both the large power and small power system studies. Summary tables are included listing the financial assumptions for each study and the solar unit and system costs. The latter table lists values in both base year dollars, and normalized to 1980 dollars. A separate reference section is included to facilitate review of the specific equations used in the economics methodology.

II. SUMMARY

A. MARKET POTENTIAL AND PENETRATION

A goal of the National Energy Program is to displace a significant portion of the U.S. annual fossil fuel consumption with solar energy by the year 2000. Projections of solar thermal energy market and system penetration conducted within the solar thermal mission analyses were typically calculated for several time periods including the year 2000. Detailed market penetration analyses have only been performed in the total energy and small power systems studies. Data available from the other studies has been used to estimate the potential size of the market for other solar thermal applications without a projection of the estimated penetration of these markets.

Market potential and penetration results for the year 2000 are shown in Table II-1, where the fossil energy displaced is in quads (10^{15} Btu), and includes oil, gas and coal. The values reflect an assumed electrical conversion efficiency of 0.3. Note that the table does not provide market penetration estimates for large power systems, and that no study of low temperature IPH was performed, although the solar total energy study did consider industrial applications where a part of both electrical and low temperature thermal needs were met. Some further comments on the table are in order:

- A recent review of current (1980) energy prices in the Southwest indicate that they already correspond to the 1985 price forecasts used in developing most of the market penetration estimates, and the latter thus tend to be conservative.
- The studies generally assumed a nominal federal investment tax credit of 10%. Recent legislation such as the Crude Oil Windfall Profit Tax Act of 1979 provides an additional 15% energy investment credit to industrial solar users, which would increase the calculated market penetration by the year 2000.

**Table II-1. Solar Thermal Power Systems National
Impact by the Year 2000**

STUDY	MARKET POTENTIAL		MARKET PENETRATION	
	FOSSIL ENERGY DISPLACED (QUADS)	BASIS	FOSSIL ENERGY DISPLACED (QUADS)	BASIS
LARGE POWER SYSTEMS STUDY -SOUTHWEST	1.75	ESTIMATE ASSUMED INTERMEDIATE LOAD GROWTH RATE OF 7.8%/YR; SOLAR FRACTION OF ~50%	-	NOT ADDRESSED IN STUDY
LARGE POWER SYSTEMS REPOWERING STUDY	0.40	*BASED ON OTHER CONTRACTOR'S ESTIMATES OF 10 GW _e REPOWERING IN SOUTHWEST AND SOLAR FRACTION OF ~45%	-	NOT ADDRESSED IN STUDY
SOLAR TOTAL ENERGY AND HI-TEMP. IPH STUDIES	7.95	FOR INDUSTRIAL APPLICATIONS. IPH STUDY ASSUMED WEIGHTED SOLAR FRACTION OF 35%	1.74*	BASE CASE ASSUMED 10% INVESTMENT TAX CREDIT AND NO SELL-BACK OF ELECTRICITY
SMALL POWER SYSTEMS STUDY -UTILITIES	0.26	BASED ON 7.03 GW _e MARKET AND ~ 37% SOLAR FRACTION	0.013	INCLUDED REPLACEMENT AND REPOWERING
SMALL POWER SYSTEMS STUDY -INDUSTRIAL	0.068	BASED ON 2.11 GW _e MARKET AND ~37% SOLAR FRACTION	0.002	REPOWERING ONLY
SOLAR IRRIGATION STUDY	0.49	ASSUMED SELLBACK OF EXCESS ENERGY TO UTILITY; INCLUDED 17 WESTERN STATES	0.12	CALCULATED ASSUMING SOLAR COST REDUCTION OF 28% FROM 1985 TO 2000
LOW TEMPERATURE IPH (<360°F)	-	NO STUDY PERFORMED	-	-

*INCLUDES ESTIMATED HI-TEMP. IPH CONTRIBUTION OF 0.11 QUADS

- The solar total energy systems were sized based on electrical demand, with additional collector area provided to minimize cost of combined thermal and electrical output. Sizing based on thermal demand, with sellback of excess electrical energy (cogeneration) as encouraged by Section 210 of the Public Utility Regulatory Policies Act of 1978 could increase the market penetration shown in the table.
- Application of solar total energy systems to lower temperature processes within the high-temperature industries (primarily petroleum refining) could increase the forecast market penetration by as much as 0.4 quads.

Considering all of the above, and assuming a reasonable penetration for the IPH and large power market sectors, the study results are consistent with a national solar thermal systems goal of displacement of three quads of fossil fuel per year by the year 2000¹.

B. MAJOR STUDY FINDINGS

The major findings of the solar thermal power studies are summarized in Table II-2. In reviewing these, the reader is cautioned to note the date when each study was completed. Since they cover a seven-year span, numerous changes have occurred which affect some of the results, especially where economic evaluations were concerned. Since 1972, the nation has been subject to an oil embargo, a recession, unprecedented OPEC price boosts, and double-digit inflation. There has been increased government support for solar research and development, and legislation to encourage solar adoption. Improved solar system performance, new insolation data, revised energy demand growth rates, and improved methodology and analysis techniques have also affected the various study results. In attempting any comparisons, the reader should review the detailed study results in Section III, and especially the financial and solar cost assumptions summarized in Appendix B.

¹See page 3, Solar Thermal Power Systems Program Summary, DOE Report No. DOE/CS-0145, dated December 1979.

Table II-2. Major Findings of Aerospace
Solar Thermal Power Studies

STUDY	MAJOR FINDINGS
<p>Large Power Systems -- Southern Calif.</p> <p>Completion Date: October 1973</p> <p>Configuration: Parabolic Trough</p> <p>Size: 1000 MW_e</p>	<ul style="list-style-type: none"> • Solar thermal systems appear competitive by 1990 for intermediate load applications in Southern California. • Storage capacity requirement of six hours equivalent operation or less is adequate. • Suitable land areas can be identified for siting • Variability of insolation significant even over the limited Southern California geographic region. • Appropriate methodology must consider total utility systems to assess worth of solar thermal power plant. Hour-by-hour simulation of solar plant output using insolation and utility demand profile required for proper evaluation.
<p>Large Power Systems - Southwest</p> <p>Completion Date: August 1974</p> <p>Configuration: Central Receiver</p> <p>Size: 100 MW_e</p>	<ul style="list-style-type: none"> • A Central receiver concept for intermediate loads is the preferred combination, with a fossil hybrid identified as the next best concept. • Modules with collector area/thermal storage of 1 kW²/6 hr per 100 MW_e would be economically viable in the 1990-2000 period. • Suitable siting areas totaling 21,000 to 161,000 square miles exist in the Southwest. Potential power generation is significant from a National perspective. • Standardized hourly insolation data tapes developed for consistent evaluation by all users.
<p>Large Power Systems - National</p> <p>Completion Date: April 1976</p> <p>Configuration: Central Receiver</p> <p>Size: 100 MW_e</p>	<ul style="list-style-type: none"> • On a national basis, California and Texas regions show competitive solar busbar costs. • Optimum design parameters not modified significantly by changes in utility location or summer-winter peaking of utility demand. • Substantial solar penetration requires significant backup capacity to maintain loss-of-load probability.
<p>Large Power Systems - Societal Impacts Analysis</p> <p>Completion Date: December 1978</p> <p>Configuration: Central Receiver</p> <p>Size: 100 MW_e</p>	<ul style="list-style-type: none"> • Societal benefits of alternative power plants can be evaluated from a national perspective through calculation of Net National Economic Benefits (NNEB). • Solar provides net national benefits for investment in 1985 relative to oil plants, in 1990-1995 relative to coal plants, based on sample calculation for Arizona and Florida.

**Table II-2. Major Findings of Aerospace
Solar Thermal Power Studies**

- Continued -

STUDY	MAJOR FINDINGS
<p>Large Power Systems - Advanced Central Power Systems</p> <p>Completion Date: February 1978</p> <p>Configuration: Central Receiver</p> <p>Size: 100 MW_e</p>	<ul style="list-style-type: none"> • Advanced sodium systems, Brayton combined cycle, and hybrid systems offer a potential 10-15% improvement in energy costs. • Increased solar penetration in utilities will require additional fractional conventional capacity to compensate for insolation outages and maintain loss of load probability.
<p>Large Power Systems - Repowering</p> <p>Completion Date: October 1979</p> <p>Configuration: Central Receiver</p> <p>Size: 100 MW_e</p>	<ul style="list-style-type: none"> • Repowering with water-steam technology is a high confidence option, compatible with nonreheat plants without storage. • Small amount of buffer storage is essential for efficient hybrid operation. • Acceptable cost-benefit ratios can be expected for most Southwest utilities.
<p>Solar Total Energy Systems</p> <p>Completion Date: November 1979</p> <p>Configuration: Central Receiver</p> <p>Size: 10 KW_e to 10 MW_e</p>	<ul style="list-style-type: none"> • Ratio of thermal to electric demand is an important parameter in determining economic feasibility. • Favorable 1990 economics projected for agricultural and industrial chemicals, paperboard mills, plastics and pharmaceuticals, with early penetration in the sunbelt states. A possible national energy displacement of 2.3 quads is estimated by the year 2000 if cost projections are achieved. • STES Handbook developed to permit users to economically evaluate their specific total energy applications
<p>Solar Thermal Small Power Systems</p> <p>Completion Date: August 1979</p> <p>Configuration: Central Receiver</p> <p>Size: 10 MW_e</p>	<ul style="list-style-type: none"> • Market penetrations for utilities and industry are expected to be small (14% and 5% respectively by 2015), unless government incentives are offered or solar equipment costs are reduced. • Small utilities expansion plans require early availability of a small solar option to avoid pre-empting access to this market.
<p>Solar Irrigation Systems</p> <p>Completion Date: May 1978</p> <p>Configuration: Parabolic Trough</p> <p>Size: 80 kW_e</p>	<ul style="list-style-type: none"> • Out-of-season solar-generated energy must be sold to penetrate irrigation system market. • Earliest penetration likely in Southeast Arizona • Solar cost reduction plus government incentives are required to achieve penetration. Maximum energy savings would be 0.3 percent of national use.

Table II-2. Major Findings of Aerospace
Solar Thermal Power Studies
- Concluded -

STUDY	MAJOR FINDINGS
Storage System Analysis Completion Date: September 1977	<ul style="list-style-type: none"> • Current and advanced techniques which increase the maximum storage operating temperature at central receiving power plants can significantly reduce busbar energy costs. • Shared centralized energy storage for load leveling can be augmented by solar power to provide both cost and fuel savings.
Mid and High-Temperature Industrial Process Heat (> 350°F) Completion Date: January 1979	<ul style="list-style-type: none"> • Review and surveys indicate potential applications in the petroleum, cement, glass, brick, and paper and pulp industries. • Except for secondary aluminum, primary and secondary metals have very little potential for solar IPH. • Enhanced use of solar in the cement, glass and brick industries could require pursuit of ceramic receiver technology to extend the solar energy temperature range to 2700°F, and development of efficient hot air transport techniques.
Solar Fuels and Chemicals Completion Date: January 1979	<ul style="list-style-type: none"> • A number of new, closed-loop thermochemical processes were identified which can use solar to transform carbon dioxide into carbon monoxide for use as a fuel, or a feedstock for the production of energy intensive chemicals. • Experimental work is required to determine the reaction rates at the predicted temperatures of the closed-loop carbon cycles.

C. EXTENSION OF MISSION ANALYSES

Solar thermal mission analysis activities to date have indicated that the most promising areas for fossil fuel savings included large power, total energy, and industrial process heat systems. National programs have subsequently been established for the technical development, applications engineering, testing and commercialization of these systems. As a result,

new data is being continuously generated on solar equipment performance and costs. Insolation data from a nation-wide measurement program is just now becoming available. With these new inputs, and the changes in fuel price and energy use forecasts discussed previously, it is appropriate to update the market analysis studies. Some of the updating may be implemented through sensitivity data already available while others may require more extensive simulation and analysis.

In addition to the updating, the mission analyses should be extended to include a number of study phases which were not addressed in the original effort. As can be seen from the gaps in Table I-2, a rigorous market analysis and survey of large power systems still remains to be performed, as well as a complete mission analysis of lower-temperature industrial process heat systems. In developing criteria and forecasts for the market penetration of large power solar systems, the importance of the utility interface should be recognized. Some of the issues which should be addressed include the following:

- Effect of solar on the utilities reserve margin and spinning reserve.
- Quick load-pickup requirements.
- Effect of solar capital investment on cash flow and expansion plans.
- Operation of the solar plant relative to both capacity credit and fuel savings
- Siting requirements outside of the Southwest, and possible use of Southwest sites by non-Southwest utilities.

Insights gained during the performance of these mission analyses suggest some additional areas which should be pursued. One such area is in the use of solar costs. In most of the market penetration studies, a fixed solar cost is used, based on an assumed solar equipment production level. Actually, this level will depend on the market penetration, and an iteration technique could be used to find the balance between the two. If no market penetration results, government incentives or other cost reduction

techniques could be factored in to determine the level required to achieve a given penetration. This in turn would help to provide a basis for determining the government level of expenditures in R&D and industrialization needed for a successful solar thermal program.

Another area of study is the continued analysis of advanced systems and concepts. For example, as more is learned about solar fuels and chemicals, advanced conversion cycles, and high-performance industrial process heat systems, these results should be input to the appropriate phases of the mission analyses. There has been substantial progress in the development of attractive and potentially competitive solar thermal systems in the eight years of existence of the national programs, with further evolutionary development pursuing the most attractive of these systems and application concepts clearly appropriate. A continuation of studies and analyses of new and innovative system concepts and applications is also appropriate. Those efforts should concentrate on meeting critical national needs such as mobility fuels or on high payoff concepts which may be made viable by technical breakthroughs.

III. DETAILED STUDY RESULTS

A. LARGE POWER SYSTEM STUDIES

The first mission analysis of solar large power systems performed by Aerospace was for the Southern California region, and was sponsored by the National Science Foundation in 1973. The methodology developed in this study was expanded and subsequently utilized in studies for NSF, ERDA, and DOE which covered Southwest and national applications. Its features included:

- Area definition and siting analysis
- Development of demand forecasts
- Definition of conceptual design(s)
- Insolation data base development
- Simulation of system performance
- Comparison of solar versus conventional system economics and capacity displacement considerations
- Identification of preferred systems and applications

Regional study results, and special studies concerning societal impacts, advanced designs and repowering implications are discussed in detail in the paragraphs below.

1. SOUTHERN CALIFORNIA STUDY

In this study, a 1,000 megawatt solar thermal electric plant using parabolic trough collectors oriented E-W with N-S diurnal tracking was specified at the onset consistent with earlier specifications from NSF. The mission analysis examined base, intermediate, and peaking applications, with the solar plant integrated in a large power grid. The Southern California area was initially addressed for the time period 1980 to 2000 in order to narrow the scope of the study. The location of The Aerospace Corporation in the Southern California area facilitated access to much of the required

data. Analyses for the Southern California area proved to be broadly representative for solar thermal conversion applications because of the wide variety of climatic, demographic, geomorphic, and physiographic conditions within the region, as well as the presence of several major load centers.

a. Area Definition and Siting

One of the first tasks to be performed was to define the Southern California area. Several aspects were considered including demographic, geomorphic, physiographic, climatologic, and institutional characteristics, as well as utility service districts. Figure III-1 shows the area selected for detailed study. It is defined by the service territory boundary for the Southern California Edison Company (SCE) on the north, Nevada and Arizona on the east, Mexico on the south; and the Pacific Ocean on the west. The reason for this selection was primarily to facilitate the demand data characterization of the area. This area is serviced electrically by a major regional utility company, Southern California Edison Company; a large municipal utility company, Los Angeles Department of Water and Power (LADWP); a large private utility company, San Diego Gas and Electric; and several small municipal utility companies, such as in Pasadena, Riverside, Azusa, etc. Furthermore, the boundary line selection is broadly coincident with that of the principal Southern California weather regions. This feature appeared desirable in terms of relating weather information with power demand.

In the siting analysis, criteria were developed for excluding certain areas on both technical and institutional grounds. The technical criteria considered grade, soil consistency, meteorological factors, vegetation, and seismic activity, while the institutional criteria excluded national parks and forests, urban areas, military reservations, urban and high-value farming areas, and public domain. With all the exclusions considered, the land area available for solar collector siting ranged from 5,000 to 11,500 square miles, depending on the seismic criterion, which was sufficient to

b. Demand Analysis

Demand data compiled in the study included hour-by-hour utility aggregate power demand profiles and projections of annual peak power levels in the 1990-2000 time period. These data were used in computer simulations to estimate solar thermal plant power output based on incoming insolation and used in margin analyses to determine the capacity displacement of solar plants operating as part of a power grid. These performance calculations were combined with cost and economic analyses to determine optimum solar plant parameters. The approach used in this study was to develop a demand profile forecasting model. Historical data were acquired from utilities, decomposed into trend, weather, seasonal and hourly factors, and recomposed along with predicted trend data to yield hourly data for the 1980-2000 time period. A sample of the decomposition technique using SCE data is shown in Figure III-2.

Figure III-2. Electric Power Demand Decomposition

c. Insolation Data Base

The performance evaluation of solar systems employing focusing collectors requires hourly data on direct normal insolation. Since few measurements of this parameter were available, an estimation technique was developed from a linear correlation between direct and total insolation, based on 5000 data pairs measured in Albuquerque, New Mexico and Blue Hill, Massachusetts (clear sky only).

In order to generate the data base for Southern California, total insolation and weather measurements available from five stations during 1962 and 1963 were analyzed. A correlation between total insolation and opaque sky cover led to the selection of a third-order polynomial as an estimating relationship, which was used to develop total insolation for three additional stations. Estimates of direct insolation for all eight stations were then developed using the linear correlation relationship between total and direct insolation. A summary of the insolation data base sources is shown in Table III-1. The data base for the two year period was stored on computer-compatible, magnetic tape, sorted into the following categories:

Table III-1. Insolation Data Base Sources

REGION	STATION	EXTRATERRESTRIAL INSOLATION	SOLAR POSITION	SURFACE WEATHER	HOURLY TOTAL INSOLATION	DAILY TOTAL INSOLATION	PERCENT OF POSSIBLE TOTAL INSOLATION	DIRECT INSOLATION
COAST	LA AIRPORT	C	C	M	M	M	C	E
INTERMEDIATE VALLEY	RIVERSIDE	C	C	M	M	M	C	E
COASTAL VALLEY	LA DOWNTOWN	C	C	M	M	M	C	E
COASTAL VALLEY	SANTA MARIA	C	C	M	M	M	C	E
DESERT	INYOKERN	C	C	M	M	M	C	E
LOW DESERT	YUMA	C	C	M	E	E	E	E
COAST	SAN DIEGO	C	C	M	E	E	E	E
DESERT	EDWARDS AFB	C	C	M	E	E	E	E
SUPPLEMENTAL	ALBUQUERQUE	C	C	M	M	M	C	M
SUPPLEMENTAL	BLUE HILL	C	C	M	M	M	C	M

C - Calculated
M - Measured
E - Estimated

- Identifying information, which includes such information as date, time, and solar position
- Insolation data, including the extraterrestrial, normal incidence and total insolation, as well as the ratio of total to extraterrestrial insolation
- Weather data including temperature, humidity, sky cover, and information on cloud cover and winds

In contrast to the insolation data, the weather information was incomplete; no effort was made to fill in the missing data. The insolation data for the Inyokern, California and Albuquerque, New Mexico stations were designated by the National Science Foundation as the standard insolation data base for use by all Solar Thermal Conversion System contractors.

d. System Evaluation

A computer model was developed to examine the importance of various solar power system characteristics in balancing the dynamic interaction of insolation and demand as shown in the block diagram of Figure III-3. This model consists of modular subsystem routines to facilitate substitution of more complex subroutines as these evolve. The insolation subroutines are the hourly total and normal incidence insolation data, representative of the various climatological subregions of Southern California.

The tracking model applies the appropriate geometrical and tracking corrections for the alternative collector configurations analyzed and includes a sky brightness model. Thus, the tracking model will compute the insolation energy which can potentially be collected.

The collector subsystem for a particular operating temperature was represented by its collector area and thermal efficiency. Provision is made for incorporation of a threshold insolation level, below which the collector does not operate. Similarly, the energy transport subsystem, for a given operating temperature, is simply represented by its efficiency. The thermal energy can be utilized directly by the turbogenerators, or stored for future utilization, depending on the power demand and generator rating.

*Turbogenerator

Figure III-3. Simple System Block Diagram

The storage subroutine incorporates a maximum and minimum storage capability as well as an overflow provision. A representative thermal energy heat loss rate is also incorporated within this model.

The turbogenerator subroutine converts the thermal energy into electrical energy with a conversion efficiency that is a function of the operating temperature. The turbogenerator model incorporates a maximum design (name plate) rating, as well as a minimum level of operation.

The electrical energy generated, when transmitted and combined with the conventional systems power output, is matched to meet the demand corresponding to use of the plant in an electrical base, intermediate, or peaking mode for any given forecast year. Each mode of operation was approximated by examining a band across the hourly demand profile as in Figure III-4. The model permits the simulation of one or more solar power plants integrated into a power grid on an hour-by-hour basis for at least a full year.

The model was applied to the 1990 demand loads shown in Figure III-4, using insolation data for a Yuma, Arizona location, and a solar thermal power plant with the following characteristics:

- Parabolic collectors with E-W orientation, N-S tracking
- Collector/thermal transport combined efficiency of 45%
- Thermal storage heat loss of 2%/hour
- Turbo-generator with a rating of 1000 MWe, minimum operating level of 100 MWe, and efficiency of 30%

Figure III-4. Electric Power Demand 1990
So. California Edison Company

For each demand load, hourly output of the turbogenerator was summed to obtain annual energy displacement and solar capacity factor, while the collector area and thermal storage capacity were varied parametrically. A carpet plot of the results for the intermediate load case is shown in Figure III-5. It is seen that there is little improvement in performance for storage times greater than six hours, and collector areas beyond 20 km².

- CONCENTRATING COLLECTOR ($\eta_c = .45$)
- TURBO-GENERATOR RATING $\sim 1000 \text{ MW}_e$ ($\eta_{TG} = .30$)
- LOCATION $\sim$ YUMA, ARIZONA
- TIME PERIOD $\sim$ 1990

Figure III-5. Intermediate Solar Thermal Conversion Power Plant

In order to determine optimum plant characteristics and preferred operational modes, a comparative economic evaluation was made with conventional power plants. The computer model developed for this evaluation utilized base-year (1972) capital investment costs and escalation and interest-during-construction routines to determine 1990 busbar energy costs for each solar power plant configuration and conventional (coal and nuclear) plant. Assumptions included an inflation rate of 3%, after-tax cost of capital of 7.4%, and fuel escalation rate of 2% to 9% (above inflation). Solar plant capital costs for a 1000 MWe intermediate plant were calculated at $\$891/\text{KW}_e$ (in 1972 dollars), including collector costs of $\$25/\text{m}^2$ and storage costs of $\$12/\text{KW}/\text{hr}$.

A comparison of solar and fossil plant energy costs for an intermediate mode of operation is shown in Figure III-6. Note that the solar costs include a component for backup capacity. This was determined by a reserve margin analysis in which solar plants were substituted for conventional units such that a fixed loss-of-load probability (one day in ten years) would be maintained. There is also a credit given for baseload energy displacement. This arises for certain combinations of collector area and storage, where solar power is available and storage is full during periods of low or zero demand within the 20,000-21,000 mWe "intermediate band,". Because of the low marginal cost of solar energy, once the solar plant has been built (because of zero fuel cost), it was assumed to continue operating, displacing energy in the base load region; however, no capacity displacement was assumed for this base load energy displacement.

Figure III-6. Total Busbar Energy Cost Intermediate Load (1990)

e. Summary of Findings

From the economic evaluation, it appeared that solar plants were best suited for intermediate mode operations, and could come close to conventional energy production costs, even matching them if collector costs could be reduced to \$15/m² (in 1972 \$) by 1990. For the 1000 MWe size, preferred plant characteristics included a collector area of 20 km² and six hours of thermal storage.

In this first comprehensive evaluation of solar thermal plants in a realistic operating environment, a number of milestones were achieved. These included development of models for demand forecasting, reserve margin analysis, performance simulation, and power plant economic evaluation, and creation of insolation and siting data bases. Documentation of this program effort is contained in References III-1 through III-6, and the results were sufficiently encouraging to NSF to initiate follow-on studies involving broader geographic areas (the Southwestern United States) and more comprehensive configuration tradeoff studies.

2. SOUTHWEST STUDY

The follow-on study for NSF was begun in November of 1973, and included the eight Southwestern states of California, Nevada, Utah, Colorado, Arizona, New Mexico, Texas, and Oklahoma. A siting analysis employing exclusion techniques similar to the previous study indicated a minimum potentially suitable land area of 21,500 square miles, which was over four times the area needed to meet the forecast energy demand for the Southwest through the year 2000.

a. Data Base Expansion

To develop demand projections for input to the system simulation, raw demand data, consisting of punched cards representing long-term hourly load histories of eight utility companies were processed for computer analysis. With this demand data base, the demand decomposition/recomposition forecast model was used to project hourly load profiles for the time period

1980-2000, which combined the peak projection with historically determined seasonal and hourly cyclic patterns. In addition, these data were analyzed to determine the annual load duration and total energy profiles for the individual utilities within the Southwestern United States. Samples of the demand data are shown in Figure III-7. The utilities analyzed were:

Los Angeles Department of Water & Power
Southern California Edison Company
El Paso Electric Company
San Antonio Public Service Board
Public Service of New Mexico
Pacific Gas & Electric
Sacramento Municipal Utility District
Arizona Public Service

The insolation data base was also expanded to include weather and insolation data from 20 sites, representing the major climatic regions of the Southwest. Data for Omaha, Nebraska were also included in the data base. Omaha, Albuquerque, and Tucson were the only stations within the Southwest for which any normal-incidence or direct insolation measurements were available and even for these locations the observations were limited. To complete the record for these stations and for the other stations, the direct insolation was estimated from the total insolation using the algorithm previously developed for Southern California. The data base was stored on computer-compatible tape, and made available to all contractors. A summary of the tape content is shown in Table III-2.

Figure III-7. Comparison of Southwestern United States Utility Demand Profiles for 1972

Table III-2. Insolation Climatology Data Base

- REPRESENTATIVE CLIMATIC REGIONS IN SOUTHWESTERN UNITED STATES
- TIME PERIOD 1962 - 1963 (2 year data base)
- HOURLY DATA ON MAGNETIC TAPE
(optionally available on 7-track BCD or 9-track EBCDIC tapes)
- TAPE 1
 - ALBUQUERQUE, N.M.
 - INYOKERN, CA
 - YUMA, AZ
 - EDWARDS A.F.B., CA
 - RIVERSIDE, CA
- TAPE 2
 - LOS ANGELES CIVIC CENTER, CA
 - LOS ANGELES AIRPORT, CA
 - SAN DIEGO, CA
 - SANTA MARIA, CA
 - FRESNO, CA
- TAPE 3
 - TUCSON, AZ
 - SALT LAKE CITY, UT
 - PHOENIX, AZ
 - ELY, NV
 - GRAND JUNCTION, CO
- TAPE 4
 - UMAHA, NE
 - FORT WORTH, TX
 - DODGE CITY, KS
 - MIDLAND, TX
 - EL PASO, TX
- CONTENTS:
 - IDENTIFYING INFORMATION
 - DATE, TIME, SOLAR POSITION
 - INSOLATION
 - EXTRATERRESTRIAL, NORMAL INCIDENCE, TOTAL PERCENT OF POSSIBLE TOTAL INSOLATION
 - WEATHER DATA
 - TEMPERATURE, HUMIDITY, SKY COVER, CLOUDS
 - WINDS

b. System Evaluation

At this point in time, preliminary performance and cost data became available from other NSF contractors, and were used in a comparative analysis of alternative solar thermal systems. The concepts which were evaluated included:

- Central Receiver System
- Parabolic Cylinder Trough, including N-S, E-W, and polar orientations
- Paraboloidal Dish

Modules of the Aerospace simulation model were modified to accommodate these concepts, and performance simulations were run based on a 100 MWe solar plant located in Inyokern, California, using the 1963 direct insolation data

base developed for this station and using the Southern California Edison Company service area hourly demand forecast for the year 1990. The 100 MWe size was selected rather than the 1000 MWe size used in the Southern California study, since the latter required an excessively large contiguous land area, and would lead to unrealistic tower heights and complex piping interconnections. The resultant yearly average subsystem efficiencies are shown in Figure III-8 for each of the alternative configurations.

SUBSYSTEM EFFICIENCIES

SUBSYSTEMS	CENTRAL RECEIVER	PARABOLIC CYLINDRICAL TROUGH			PARABOLOIDAL DISH
		POLAR	N-S	E-W	
COLLECTOR					
TRACKING	} 0.703	0.957	0.876	0.724	1.000
AIMING		0.945	0.918	0.849	0.940
SHADING		0.867	0.888	0.978	0.860
BLOCKING		--	--	--	--
FIRST REFLECTIVITY	0.880	0.880	0.880	0.880	0.880
SECOND REFLECTIVITY	--	0.960	0.960	0.960	--
RECEIVER					
ABSORPTIVITY	0.900	0.900	0.900	0.900	0.850
THERMAL LOSSES	0.970	0.895	0.884	0.873	0.972
DISTRIBUTION PUMP LOSSES	0.985	0.970	0.970	0.970	0.962
DISTRIBUTION LINE THERMAL LOSSES	1.000	0.900	0.900	0.900	0.900
TURBINE/GENERATOR	0.360	0.320	0.320	0.320	0.340
OVERALL EFFICIENCY ⁽¹⁾	0.192	0.149	0.134	0.111	0.173

⁽¹⁾ Does not include Waste Heat or Storage Losses

Figure III-8. Solar Thermal Conversion Systems
Subsystem Efficiencies

The overall efficiency reflects all the losses from insolation input to electric power output and, consequently, is of primary significance in comparing the various system concepts. The overall efficiency does not include waste heat or storage losses, as these are a function of the particular operational mode considered. As can be seen from this figure, the central receiver concept had the highest overall efficiency (19.2%), and the E-W oriented parabolic cylindrical trough the lowest (11.1%).

Simulations were run for each concept, in which collector area and storage size were varied parametrically to determine optimum values for base load, intermediate and peaking operation. These results were subsequently used along with the solar plant cost estimates of Table III-3 in the Power Plant Economic Model to determine busbar energy costs for each concept.

Table III-3. Intermediate Solar Thermal Power Plant Cost Estimates
\$/KW_e (100 MW_e (Rated))

PLANT TYPE	C. R.	DISH	POLAR	N-S	E-W	E-W
COLLECTOR AREA (KM ²)	1	1.15	1.20	1.2	1.5	1.5
COLLECTOR COST (\$/m ²)	30	60	70	60	60	15
STORAGE CAPACITY (hr)/COST ~\$15/KW _e /hr	6	8	8	8	8	8
ACCOUNT						
LAND	2	2	2	2	3	3
STRUCTURES AND FACILITIES	44	49	49	49	49	49
HELIOSTATS/COLLECTORS	300	690	875	720	900	225
RECEIVER/TOWER/HEAT EXCHANGER/THERMAL TRANSPORT	95	244	319	254	318	318
STORAGE/TANKS	90	120	120	120	120	120
TURBINE PLANT EQUIPMENT	80	80	80	80	80	80
ELECTRIC PLANT EQUIPMENT	21	21	21	21	21	21
MISC PLANT EQUIPMENT	4	4	4	4	4	4
ALLOWANCE FOR COOLING TOWERS	20	20	20	20	20	20
TOTAL DIRECT COST	656	1230	1490	1270	1515	840
CONTINGENCY ALLOWANCE	39	72	88	74	89	45
SPARE PARTS ALLOWANCE	3	8	10	8	10	5
INDIRECT COSTS	78	90	101	92	102	78
TOTAL CAPITAL INVESTMENT (1973)	776	1400	1689	1444	1716	968
ESCALATION TO START OF CONSTRUCTION	296	499	603	515	614	342
TOTAL AT START OF CONSTRUCTION	1072	1899	2292	1959	2330	1310
INTEREST DURING CONSTRUCTION	119	178	210	183	214	127
ESCALATION DURING CONSTRUCTION	169	291	355	301	360	198
TOTAL COST AT YR COMMERCIAL OPERATION (1990 dollars)	1360	2368	2858	2443	2904	1635

As can be seen from Figure III-9, the central receiver concept was preferred, provided the projected unit collector costs could be achieved. This concept provided competitive busbar energy costs when compared with intermediate load operation of a 400 MWe combined-cycle fossil fuel plant (assuming fuel cost escalation rates of 5% per year).

Figure III-9. Intermediate Solar Thermal Conversion Power Plants
Comparative Economic Evaluation

c. Summary of Findings

During this study, the models and techniques developed previously were refined and utilized to perform solar plant configuration tradeoff studies. The primary preferred system identified was the intermediate load stand-alone central receiver power plant. A modular concept for this system appeared to be desirable, limiting the tower height to less than 300 m. A collector area of 1 km^2 and thermal storage capacity of 6 hours per 100 MWe rated plant capacity, resulted in the lowest busbar energy cost. The heliostat and thermal storage cost objectives of $\$30/\text{m}^2$ and $\$15 \text{ KW/hr}$, when realized, would meet the long-time economic viability criterion of providing electric power with a competitive busbar energy cost of 40-50 mills/kWh (1991 dollars). This concept appeared to be technically feasible, although the relative development risk associated with the receiver was considered high.

Because the thermal storage subsystem was not well defined, a hybrid concept central receiver power plant with limited storage ($\sim 0.5 \text{ hr}$) operating in the intermediate mode was identified as an alternate system. Since a conventional fossil fuel boiler replaces the long-term thermal storage subsystem, the collector area required per 100 MWe rated plant capacity was 0.5 km^2 . Otherwise, the same system definition and cost objectives as defined above for the stand-alone central receiver power plant applied.

The Southwest study is documented in References III-7 through III-11. A preliminary market capture potential of 40,000 MWe by the year 2000 was identified for the preferred system concept (Ref. III-10). This would result in the saving of 320 million barrels of oil per year, or 1.8 quads of energy annually. Subsequent studies addressed the question of economic viability for other geographic regions, and national market potential.

3. NATIONAL STUDIES

Mission analysis of solar thermal power systems continued under ERDA sponsorship in 1975. The encouraging results of the Southwestern study led to renewed interest in the performance and operating economics of similar solar plants located in other sections of the country, and the effects of different insolation levels and load profiles on system optimum design. A study was therefore initiated to provide a fairly detailed comparison of solar plants operating in regions of the U.S. outside of the Southwest, and to explore the potential market for solar plants in those regions not previously considered.

Because of the large number of utilities operating within the U.S., it was necessary, in order to keep the study within manageable limits, to select one or more "representative" utilities from various regions, and to pair these with selected insolation stations for which credible insolation measurements were available. By doing this for a sufficient number of geographically distributed utilities, it appeared possible to develop a detailed understanding of where solar plants could be sited effectively.

The selection of appropriate utilities was based on a review of data from 40 utilities, including the 16 utilized in the Southwest study and the 24 listed in Table III-4. Load characteristics which were examined included power and energy growth trends, ratio of weekly peaks in each season, and weekly load factors. Plots of the hourly load data for each utility provided additional data used in the selection process. These efforts resulted in the identification of 10 regions within which all the utility demand data appeared to have common features. Three utilities were also found (TVA, Omaha Public Power, and Commonwealth Edison of Illinois) with singular demand features which were non-representative of other nearby utilities. These demand regions and the service areas of the three singular utilities are shown in Figure III-10.

Table III-4. Utilities Selected for Demand Analysis

UTILITY ^a	AREA SERVED ^a (mi ²)	1973 PEAKLOAD (MW)	REGION	TYPE
PUGET SOUND POWER & LIGHT CO	5,000	2,115	NW	INVESTOR
PORTLAND GENERAL ELECTRIC CO	3,350	2,492	NW	INVESTOR
PACIFIC POWER & LIGHT CO	10,000	3,402	NW	INVESTOR
IDAHO POWER CO	20,000	1,794	NW	INVESTOR
MADISON GAS & ELECTRIC CO	750	350	WC	INVESTOR
OMAHA PUBLIC POWER DISTRICT	5,000	1,058	WC	DISTRICT
MONTANA-DAKOTA UTILITIES CO	168,100	209	WC/NW	INVESTOR
ARKANSAS POWER & LIGHT CO	15,000	2,607	SC	INVESTOR
GULF STATES UTILITIES CO	40,000	3,602	SC	INVESTOR
TENNESSEE VALLEY AUTHORITY	80,000	18,800	SE	GOVERNMENT
NASHVILLE ELECTRIC SERVICE	507	1,418	SE	MUNICIPAL
FLORIDA POWER CORP	20,000	2,862	SE	INVESTOR
CAROLINA POWER & LIGHT CO	30,000	4,900	SE	INVESTOR
FLORIDA POWER & LIGHT CO	22,000	7,239	SE	INVESTOR
NEW YORK STATE ELECTRIC & GAS CORP	17,000	1,701	NE	INVESTOR
BANGOR HYDRO-ELECTRIC CO	6,000	155	NE	INVESTOR
PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION	35,000	27,059	NE	INVESTOR
VIRGINIA ELECTRIC & POWER CO	22,000	6,900	SE	INVESTOR
CLEVELAND ELECTRIC ILLUMINATING CO	5,000	2,822	EC	INVESTOR
MAINE PUBLIC SERVICE CO	500	805	NE	INVESTOR
COMMONWEALTH EDISON CO	5,000	11,750	EC	INVESTOR
CONSUMERS POWER CO	10,000	4,080	EC	INVESTOR
CENTRAL ILLINOIS LIGHT CO	1,000	790	EC	INVESTOR
AMERICAN ELECTRIC POWER SYSTEM	30,000	12,097	EC	INVESTOR
TOTAL	551,200	120,282		

^a Excludes utilities previously selected in southwest.

Figure III-10. Utility Load Regions

It was also found possible to draw boundaries separating the various demand regions which closely matched the boundaries which had previously been established for climatological characteristics. As a result of these findings, a decision was made to attempt to evaluate the performance of solar plants in each of the "demand regions" which had been defined. This goal was later reduced to the goal of examining five additional sites outside the Southwest when problems were encountered in obtaining sufficiently detailed demand data from utilities in several regions. The additional sites selected for detailed performance simulation (also the locations for insolation data to be used) were:

<u>Demand Region</u>	<u>Representative Utility</u>	<u>Insolation Site</u>
1	Consumers Power Company (CPC)	Madison, Wis.
3	Florida Power & Light Co. (FPL)	Miami, Fla.
4	Pacific Power & Light Co. (PPL)	Seattle, Wash.
6	San Antonio City Public Service Board (CPSB)	Forth Worth, Tex.
9	Pennsylvania, New Jersey Maryland Intertie (PJM)	Sterling, Va. (Dulles Airport)

These regions, plus the southwestern U.S. as represented by Inyokern, California/Southern California Edison Co., covered the range of performance to be expected in other areas of interest. Seattle, Washington, because of its very poor insolation, was expected to provide a lower bound on the performance of a solar thermal power system.

A number of data base and modeling improvements were made prior to the simulation and economic evaluation phases of the study. These are documented in detail in References III-12 thru III-14. Highlights include the following:

- a. A new demand forecasting procedure which allowed for changes in the yearly demand distribution (e.g., from winter to summer peaking).
- b. An expanded insolation and climatological data base covering 34 locations.
- c. A computer simulation which determines transient effects of cloud movement on energy output of a central receiver.
- d. A revised subroutine in the solar plant operating model which accounts for efficiency losses when operating on steam from storage.
- e. A new dispatch model governing the operation of the turbine-generator.
- f. A new Utility Financial Analysis and Planning Model (UFAP) which provides information on annual cash flows and the financial condition of a solar power plant over its lifetime, as well as time-varying busbar energy costs.
- g. An updating of solar plant capital costs to reflect latest contractor design cost estimates and the then-current economic parameter estimates, as shown in Tables III-5 and III-6 respectively. Note that the former included a doubling of collector costs.

Table III-5. Comparison of 100 MW Central Receiver Capital Investment Costs

Solar Plant Element ¹	Capital Costs (\$/kW)		% Increase
	Initial Cost Estimates (1974 Dollars)	Interim and Final Cost Estimates From Table 3-7 (1975 Dollars)	
Land	2.0	3.5	75%
Structure	43.8	52.9	21
Miscellaneous	23.6	28.7	22
Turbine Plant	80.0	107.8	35
Electrical	21.0	25.9	23
Collector	354.0 ²	709.0 ³	100
Receiver			
Thermal Storage	90.0	100.0	11
Direct Plant Costs	614.4	1027.8	
Indirect Costs, Contingencies, and Spares	161.7	296.2	83
Total Plant Construction Costs ⁴	776.1	1324.0	

1) Collector Area = 1 km², Thermal Storage = 6 hr

2) 35 \$/m²

3) 71 \$/m²

4) Excludes interest during construction and inflation costs

5) Data developed in late 1977 indicate higher costs than shown here for early plants.

Table III-6. Summary Comparison of Mission Analysis Economic Parameters

Parameter	Mission Analysis Study Phases		
	Initial Study Inputs (11/74)	Interim Parameter Selection (11/75)	Final Parameter Selection
General Inflation Rate	3.0%	5.2%	5.5%
Conventional Plant Escalation Rate	2.3 - 6.1%	5.2 - 8.6%	6.5%
Solar Collector/Receiver/Thermal Storage Escalation Rate	2.8%	2.6 - 7.6%	6.5%
Fuel Escalation Rate	3.5%	6.0 - 10.0%	6.5 - 7.5%
Revenue Escalation Rate	2.0%	4.0%	0%
Applicable Data Year	1973	1975	1976
Base Year for Costs	1975	1975	1975
Cost of Money	7.4%	8.35%	11.5%

Using all of the above, performance in each of the five regions plus California was calculated in terms of busbar energy costs as a function of collector area and thermal storage size and compared with update energy costs using conventional plants. Typical results are shown in the carpet plots of Figures III-11 through III-13. It is seen that a 100 MWe solar plant with collector area of 1 km² and six hours of storage is optimum in all areas, competing with oil plants in California, nearly competing in Texas, and considerably more expensive in the other regions (of which Madison is typical).

Subsequent to this study, data became available on measured direct-normal insolation as indicated in the following table:

<u>Station Name</u>	<u>Data Period</u>
Livermore, California	1 Aug 74 through 30 Oct 75
Raleigh, North Carolina	20 Mar 75 through 1 Apr 76
Fort Hood, Texas	1 Sep 74 through 30 Jun 76
Maynard, Massachusetts	1 Jan 75 through 31 Dec 76
Albuquerque*	1 Jan 62 through 31 Dec 62

*available previously

These measurements became the basis for a new regression analysis, in which the linear regression with total insolation was abandoned in favor of a piecewise linear fit to the data. The revised insolation data base is documented in Reference III-15, and includes revisions to the total insolation data base resulting from the rehabilitation of those data by NOAA. For regions outside of the Southwest, this resulted in an average reduction in annual normal-direct insolation of 30%.

Figure III-11. SCE/Inyokern Central Receiver Power Plant Busbar Costs

Figure III-12. CPSB/Fort Worth Central Receiver Power Plant Busbar Costs

Figure III-13. Consumers Power/Madison Central Receiver Busbar Costs

Using the revised data base, the performance analysis for the five regions outside of the Southwest was repeated, and the results are documented in Reference III-16. That analysis also utilized region-specific fuel cost forecasts developed by Sherman H. Clark Associates for input to Aerospace's Solar Total Energy Studies (Ref. III-17). As expected, the solar performance was considerably reduced in all regions, even when using forecast year 2020 fuel prices. These results, however, are mitigated by the following observations:

- Recent (1979) dramatic oil price increases are far greater than the Sherman Clark prediction, already exceeding 1985 forecasts.
- Cost benefit analyses indicated that the nation will benefit from early solar adoption, and Congress is apparently willing to encourage this through legislation providing solar tax credits and low cost loans.
- Solar repowering of existing plants can reduce costs of solar capital investment.

Some of the above factors are discussed in the sections which follow.

4. SOCIETAL IMPACTS ANALYSIS

Although some of the cost studies performed to date showed that in the near term, solar generation of electrical energy in some regions would not be cost-competitive, it was recognized that the selection of a future generation mix would be significantly influenced by environmental, socioeconomic, and resource depletion effects of alternative generating techniques. This was recognized by the favorable tax credit allowances for renewable resources provided by Congress in the Energy Tax Act of 1978.

In January of 1978, Aerospace undertook a societal impacts analysis for DOE whose objective was to quantify externalities such as financial impacts, environmental impacts, and the effects of government policies on power plant options. The criterion selected was the concept of Net National Economic Benefits (NNEB). This is a systematic measurement in dollar terms of the benefits and costs that result from the construction and operation of several different types of power generation plants. The question of the definition of "societal" was resolved by adopting a national perspective.

Net national economic benefits are defined as the present value of a future stream of benefits minus the present value of a future stream of costs. Symbolically,

$$NNEB = \sum_t \frac{1}{(1+D)^t} \left[BV(t) - FC(t) - \sum_i GP_i(t) - \sum_j EC_j(t) - \sum_k R_k(t) \right]$$

where D is the social discount rate. The "benefit" term, $BV(t)$, is the time-dependent value of the electricity produced by the plant in question, while $FC(t)$ includes the cost of plant construction, operation and maintenance, and fuel. The $GP_i(t)$ terms represent the cost impact of government policies and could include taxes and subsidies (when they fall unequally on different energy generation modes), RD&D funding, environmental control criteria, installation of a strategic petroleum reserve, and national security considerations. The $EC_j(t)$ terms refer to environmental costs due to pollution of our air and water. They would include health effects, property damage, aesthetics, and waste management. The final terms, $R_k(t)$, represent resource depletion effects and include materials, land usage, and water requirements.

Details of the study are documented in Ref. III-18. The methodology used was to compare alternative power sources applicable for intermediate and peaking load applications, assuming 100 MWe coal, oil, and solar plants hypothetically located in Arizona and Florida. Capital costs of the plants were obtained from previous studies (Ref. III-14 and III-16), fuel costs from Ref. III-17, and external costs from analyses. Factors which were quantified included foreign tax credits, costs of the strategic petroleum reserve, percentage depletion allowances, pollution costs, strip-mined land reclamation costs, and the effect on the potential gross national product of projected fuel prices increases for the oil and coal burning plants. This last-named effect is quite significant, in fact, it reduces the relative net national economic benefit of coal by as much as 10%, and oil by as much as 20%.

Figure III-14 shows the NNEB difference between solar and oil, and solar and coal as a function of initial year of operation. It is seen that from an NNEB point of view, solar is already superior to oil, and is projected to become superior to coal in the 1990 to 1995 time period. Since oil costs were comparable in both states, the earlier advantage of solar in Arizona was due to the higher insolation (and therefore higher solar capacity factor) in that state while the earlier superiority of solar over coal in Florida was due to the higher anticipated coal costs in that state.

It should be recognized that this analysis was limited. A more complete analysis would include externalities which were identified but necessarily omitted for lack of time. For example, health and environmental effects associated with construction of the generating plants have not been considered, nor have accidents related to transporting fuel. The costs of regulation, balance of payment deficits, land use, and waste disposal need attention. There are also significant problems like what fraction of the national defense budget should be charged against oil for keeping the sea lanes from the Middle East open, and how one quantifies the effect on the

world's weather of loading the atmosphere with CO_2 from excessive burning of fossil fuels. Some reflection on the influence of these externalities on the NNEB calculations indicates that their effect would be to enhance the already superior social value of solar over fossil fuel plants in the period of interest.

Figure III-14. Net National Economic Benefit Comparison for 100 MW_e Power Plants

5. ADVANCED CENTRAL POWER SYSTEMS

Initial studies of solar central power systems assumed the use of available, low risk steam and storage technology. In March of 1977, Aerospace undertook an analysis of advanced system concepts for ERDA utilizing high-pressure and temperature steam systems, liquid sodium and molten salt heat transfer media in the receiver and thermal storage subsystems, open and closed Brayton cycles, and various solar-fossil hybrid systems. It was recognized that these concepts have the potential for enhanced plant performance and decreased energy production costs with only modest extensions in the state-of-the-art technology. However, these

potentials must be weighed against the technical and economic risks associated with high temperature equipment design and operation. Technical details and results of comparative economic evaluations of these concepts are discussed in the paragraphs below, and documented in Reference III-19.

a. Advanced Steam Systems

The potential of advanced steam cycles for central power system applications has been investigated because of their widespread use, demonstrated performance, and their experience in the utility industry. Figure III-15 shows a simplified flow diagram of a typical steam system (a) along with the advanced cycle design conditions as represented by the turbine inlet pressures and throttle temperatures (b). The power conversion cycles utilize dual admission steam turbines similar to that utilized in the current technology reference system as typified by the Barstow Pilot Plant. The advanced steam cycle design points for this study have included a representation of both the state-of-the-art (1000°F) and the more advanced steam conditions which represent a significant departure from current design practices (1200°F and higher). The latter designs for the conventional power plants have been studied and built, but these systems have not been proven to be more economical than the state-of-the-art technology designs. Performance and cost data were developed as a function of operating temperatures by scaling and analysis of available data. The performance and costs of conventional equipment, such as steam power conversion and the balance of plant equipment, were also based upon a scaling analysis. The dashed lines in Figure III-15 (b) represent estimates of power conversion cycle efficiencies for advanced steam systems. Solar related data is scaled or extrapolated from the reference plant data. Receiver costs have been extrapolated according to the trends indicated by high temperature boiler equipment for steam plants. The solid lines in Figure III-15 (b) represent efficiencies which could be achieved using a single phase liquid such as liquid sodium or molten salts for both the receiver coolant and thermal

Figure III-15. Advanced Steam Systems

storage. In this concept, the thermal energy from the receiver is transported to a high temperature sodium storage tank on the ground through a low pressure sodium loop. The energy is subsequently extracted from the high temperature storage through a sodium-steam heat exchanger or steam boiler to operate a water-steam superheat-reheat cycle. The sodium loop requires a pressure of approximately 500 psi. The improvements in the power conversion cycle performance are accomplished through: (1) the use of a superheat-reheat loop providing a higher temperature steam to the low pressure stage and (2) improvements in steam conditions from storage. These improvements are not feasible for the current technology system design because of the remote location of the receiver/boiler and the inherent limitations of storage subsystems. Using performance simulation and economic evaluation models, developed previously, costs of the various systems were developed in terms of busbar energy costs. These costs were normalized with respect to the current technology target reference system such that the ordinates shown in Figure III-15 (c) directly represent the potential for energy cost reduction for various options and technology levels. It is seen that adoption of advanced steam systems might improve plant performance by 5%, and use of liquid sodium or molten salt heat transfer subsystems could lead to a 10% improvement. However, specific designs have not been investigated and large uncertainties exist in the cost of sodium related equipment. Increased costs of equipment, safety requirements, and/or higher costs of operation and maintenance could offset a major portion of performance gain. In the interim similar comments can also be made for systems utilizing molten salt as the working media.

b. Advanced Brayton Cycle Systems

Brayton open-cycle single gas turbine power plants are already in use in the utility industry for peak load applications. These systems are less efficient than steam plants but the efficiency can be improved by: (1) increasing the turbine inlet design temperature, (2) by recuperation, and (3) by use of bottoming cycles. Figure III-16 (a) shows a simplified flow diagram of a solar plant utilizing an open recuperated cycle with air cooled turbine vanes and blades. Ambient air at the compressor inlet is compressed and preheated prior to entering the receiver heat exchanger. The solar configuration assumes placing the receiver and gas turbine power conversion unit on top of the tower to shorten the high temperature gas paths. The heated air from the receiver is expanded in the turbine to generate electric power. The recuperator is used to recover the waste heat from the turbine exhaust and transfers this heat to the air entering the receiver. The turbine vanes and blades are cooled by the bleed air from the compressor for high temperature operation. Current industrial designs with advanced cooling techniques are capable of operating at 1900-2000°F. Cycle efficiencies are shown in Figure III-16 (b), including improvements possible using uncooled ceramic vanes and blades. The latter would require use of a ceramic heat exchanger receiver.

Two other Brayton systems were examined; a closed cycle system and a combined cycle system. The closed cycle system permits the use of a high heat transfer pressurized gas, such as helium, and smaller machine size due to higher power density. The combined cycle system increases efficiency by recovering the waste heat in the turbine exhaust through a steam boiler to run a steam bottoming cycle.

Figure III-16. Brayton Systems

The relative economics of all of these systems (plus a hybrid system to be discussed in the next section) is shown in Figure III-16 (c). It is seen that the simple and closed cycle systems offer only small improvements, while the other systems could provide a 10 to 15% advantage. It should be noted, however, that a comprehensive receiver technology development is required to assure the feasibility of these systems. Receiver and gas turbine reliability is also a concern. Although 2000°F to 2200°F turbine inlet temperature machines could be built and operated in the 1990 time period, experience with air cooled systems for projected lifetimes of 100,000 hours for high temperature components is lacking.

c. Solar Fossil Hybrid Systems

The use of fossil combustion to augment solar thermal energy offers the potential for enhancing the operational flexibility, reliability, and performance of solar plants. Solar fossil hybrid operations can be incorporated in the water-steam Rankine systems as well as the Brayton systems in a variety of different ways, as shown in Figure III-17. In the steam hybrid and solar-fossil hybrid concepts, it replaces the solar storage subsystem, and is used to augment the solar energy and increase the reliability and flexibility of dispatch, while in the Brayton fossil boost hybrid concept it can boost the fluid temperatures of a low technology receiver and/or storage subsystems to higher temperatures compatible with the high performance turbine capabilities. Since all of the hybrid systems use fossil fuels, their busbar energy costs will be a strong function of the expected fuel escalation rate. Figure III-17 provides an economic comparison of these systems with steam solar and Brayton solar stand alone plants, and with a conventional steam oil-fueled plant. The dotted lines represent steam plants and the solid lines are for the Brayton plants. It is seen that for moderate fuel escalation rates, the hybrid plants offer an advantage, while for rates in excess of 7%, the stand alone plants are preferred.

Figure III-17. Solar-Fossil Hybrid Concepts

6. REPOWERING ANALYSIS

The economic attractiveness of solar-fossil hybrid plants as discussed above, and the desire for an early introduction of central receiver system technology provided the impetus for a study of repowering. In December of 1977, DOE requested Aerospace to examine the repowering of existing oil-fired power plants. In this initial study, the costs of the turbine, boiler and balance of plant were eliminated, and the net present value of the savings in fuel costs less the cost of the solar repowering and integration equipment were calculated parametrically as functions of collector area and fuel escalation rate.

The baseline concept is shown in Figure III-18, and assumed a steam, no-reheat power plant, where the fossil boiler replaced the solar storage subsystem, and could be utilized during insolation outages and in the event of solar equipment failures. Results of the parametric study are shown in Figure III-19, together with the baseline assumptions, and documented in Ref. III-23. All costs were in 1977 dollars, and the fuel escalation rates included an assumed national inflation rate of 5%. It is seen from the shift in maximum peak savings that it is economical to oversize the solar collector and equipment above the turbine rated capacity. The added cost of heliostats is more than compensated by increased savings in fuel and fuel costs.

Figure III-18. Solar Repowering Concept

BASELINE ASSUMPTIONS:

- SOLAR AND FOSSIL PLANT SIZE - 100 MW_e
- NO STORAGE, CF SOLAR = 0.25
- MDAC DESIGN BASIS
- INTERMEDIATE LOAD OPERATION
- COLLECTOR COST = \$88/m²
- START OF REPOWERING OPERATION, 1985
- FUEL COST (\$/MBtu) = 2.3
- SOLAR RETROFIT LIFE (yr) = 30

Figure III-19. Sensitivity to Fuel Escalation Rate

Subsequent to this initial study, interim studies of repowering were conducted which addressed several key issues, including market potential, design-specific options, and the economics of integration into utility systems. Details of these studies are documented in Ref. III-21, and major findings are summarized in the paragraphs below.

a. Market Potential

A review of plant characteristics and land availability of identified repowering candidates in the Southwest resulted in a total of approximately 10,000 MWe of solar market, including both reheat and non-reheat plants. These estimates are expected to be reduced when more detailed surveys are made and other constraints such as boiler cycling capabilities are included. On the other hand, relaxation of constraints, such as the distance of the solar tower from the fossil unit, at some performance penalty, can increase the solar market significantly. The solar capacity potential for the 1985-2000 time frame would be substantially increased when contributions of process heat and new hybrid plants to the solar market are included.

b. Design Options

A review of the available solar central receiver system technology and an investigation of the technology match with the candidate fossil plants to identify possible repowering configurations indicates that a variety of technologies would be needed to meet the differing technical requirements of the market and to accommodate the preferences of the utilities for different technologies. The repowering with water-steam system technology in general offers a higher confidence option. This technology will be better suited for repowering of non-reheat plants in applications for which storage is not required either for technical or economic reasons. However, considerations of insolation characteristics, boiler firing requirements and associated economics indicates that a small amount of buffer storage is essential for an efficient hybrid operation. The need for larger amounts of storage will depend upon the individual applications. Storage may be required in situations where little or no oil is saved by repowering (e.g. oil portion of the fuel saved by the solar energy is negated by the expenditure of oil by the fossil boiler), and where increased solar fraction, capacity credit and fuel oil savings are required for technical or economic reasons.

c. Utility Integration

The assessment of the economic attractiveness of repowering involves a complex interaction of parameters associated with solar plant design and utility system characteristics, such as load demand, site insolation, and conventional generation mix. Studies were conducted to evaluate the integration of a water-steam solar technology repowered plant into various utility systems. The measure of economic attractiveness used was the cost benefit ratio (C/B), defined as the ratio of the cost of solar retrofit equipment to the savings (benefit) to the utility. The savings include reduction in expenditures for conventional power equipment, net savings in the system fuels (oil, gas, coal, etc.) and reduction in O&M costs.

A utility simulation model was used to compute load duration curves associated with the total power generated from fossil fuel in the utility with and without solar repowering. Fuel expenditure of the repowered plant was estimated by a hybrid simulation model which accounted for boiler operating losses associated with starting, shutdown, cycling, and standby operations. Study results are shown in the bar chart in Figure III-20. The first bar represents the baseline case; a 50 MWe intermediate oil steam plant in a synthetic EPRI-E utility which is assumed to be repowered with a solar collector size of 233,000 m². The plant is located in Midland, Texas, and Aerospace insolation tapes for this location were used. An Aerospace demand forecast for 1985 developed from EPRI data was used for the demand profile and load duration curves. For the reference case, a cost/benefit ratio of .83 is obtained. The other cases represent repowering of plants for utilities in Arizona, Nevada, and New Mexico, and appear to be in the regime of economic acceptability.

Figure III-20. Economics of a Repowered Solar Plant

B. SMALL POWER SYSTEM STUDIES

Initial Aerospace mission analysis of solar small power systems in 1974 addressed the conceptual design of solar total energy systems. Subsequent studies for ERDA and DOE were expanded to include:

- Solar Total Energy Systems for Industry
- Solar Thermal Small Power Systems for Utilities and Industrial Power Plants
- Solar-Powered Irrigation Systems

Unlike the large power studies, which provided only a limited treatment of market potential, these studies developed techniques for analyzing market potential and market penetration in considerable depth from both a regional and national point of view, as discussed in the paragraphs below.

1. SOLAR TOTAL ENERGY SYSTEMS

A Solar Total Energy System (STES) is characterized by the use of solar energy for on-site generation of electricity, with recovery and reuse of turbine waste heat to meet thermal demands such as process heat, space heating and cooling, and water heating. A typical STES is shown in Figure III-21. Because much of the waste heat from the turbine can be utilized, the overall system efficiency for a STES can be considerably greater than that of a solar electric plant, and offers the promise of improved economic viability. The early studies documented in Reference III-13 identified subsystem design concepts for a 200 KWe STES using parabolic trough collectors, and defined the operating parameters required for hour-by-hour simulation. Demands (both electrical and thermal) were defined for residential, commercial and industrial applications, and comparative analyses employing a STES simulation model indicated that the industrial applications would be favored from the standpoint of economics and land

availability. Subsequent studies focused on development of market penetration estimates, field surveys of attractive applications, and techniques for assisting potential users in calculating STES performance.

Figure III-21. Typical Solar Total Energy System

a. Market Penetration

In order to develop market penetration estimates, the STES simulation model was used to determine optimum STES performance for various industrial application characteristics such as system size, thermal-to-electric demand ratio and phasing of demand relative to daily insolation. An idealized application was first defined, using the demand inputs and assumptions shown in Figure III-22 (a), and the optimum performance determined by varying collector area and the sizes of high temperature and low temperature storage as shown in the carpet plot of Figure III-22 (b). Two performance parameters were calculated; the equivalent cost ratio (ECR) -- the

annualized cost of STES relative to the annualized cost of the displaced thermal and electric energy, and the percentage fuel displacement (FD) -- the fraction of the fuel consumption displaced by the STES.

Figure III-22. Characteristics of STES Idealized Application

Having determined the performance of the idealized application, simulations were repeated for different demand (phasing) patterns, thermal-to-electric (T/E) ratios and locations, as shown in Figure III-23. Correlations were then developed which enabled ECR and FD to be expressed as mathematical functions of insolation and T/E ratio. These relationships permitted performance assessment of STES for a given industry and location without resorting to repeated computer simulation, and are documented in Reference III-22.

Figure III-23. STES Performance Sensitivity Relationships

At the time of the study, efficiency and cost figures available from contractor studies appeared to be superior for the central receiver configuration, so this configuration was used in developing STES cost as a function of size and operating time period. Cost estimating relationships were developed for each subsystem and combined to obtain total capital and operating costs. Subsystems examined included land, structure, solar plant, turbine electrical plant, master controls, miscellaneous plant equipment, and operating and maintenance costs. Costs were calculated for system sizes ranging from 10 KWe to 10 MWe for the 1985, 1990, and 1995 time periods.¹ The resulting costs ranged from a high of \$12,730/KWe for a 10 KWe plant in 1985 to a low of \$1475/KWe for a 10 MWe plant in 1995. The latter figure reflects the DOE design goal of \$65/m² for quantity heliostat production.

¹See Figure B-1 in Appendix B.

Relationships were then established between these cost data and the nominal costs used in the "idealized" system performance application simulations to estimate equivalent cost ratios for systems of different sizes. These are documented in Reference III-23.

These relationships were then combined with census data on energy use and application characteristics and used with the simulation-derived STES performance relationships to develop a computer code called SAM -- STES Application Model, as shown in the block diagram of Figure III-24. Use of this code provided the ECR and fuel displacement by fuel type for all combinations of 140 industries, 50 states, and 7 future time periods between 1985 and 2015. The required data inputs for energy use and price forecasts of competing fuels (by fuel type, user type and state) were developed by Sherman H. Clark Associates under subcontract to Aerospace (Reference III-17). Detailed results and summaries by state and by industry were given by the model. SAM results indicated that the manufacturing industries will require 16.5 quads of energy in 1985, increasing to 26.5 quads by 2015. Of these totals, approximately 32% are high temperature demands ($> 600^{\circ}\text{F}$) which STES configurations (as described in this study) could not replace. Of the remainder, STES has a potential of displacing approximately 51% of the fuels used (5.6 quads in 1985 and 9.5 quads in 2015). In terms of the scarce fuels such as natural gas and oil, STES has a maximum displacement potential of 4.1 quads annually. This is shown in the bar chart of Figure III-25.

It should be noted that the size of the STES markets cited above are maximum potential displacements, independent of economics. For many of these applications, however, the minimum ECR will be greater than 1 and hence these applications will not be economically attractive. When only those STES industrial applications were sought which were projected to have an ECR less than 1 by 1985, none were identified and only two (California paint and drug manufacturing) were identified for the 1990 period. By 1995,

Figure III-24. STES Application Model (SAM) and Market Penetration Model (MPM)

Figure III-25. STES Energy Displacement Potential

however, 114 economically viable STES applications in fifteen different states were identified, and these applications could displace a total of 0.8 quads annually. Promising STES applications were identified in California, Texas, Florida, Hawaii, and New Jersey. Industries with large potential fuel displacements included agricultural chemicals, industrial organic chemicals, plastics, and drugs.

In order to estimate expected STES market penetration rather than maximum potential, a second computer code was developed called the Market Penetration Model (MPM). The MPM program accounted for size-related variations in STES costs and geographic variations in insolation and competing fuel prices. The model took suitability into account and considered new construction only, since retrofit would have involved considerably higher costs, installation difficulties, and problems with land availability. Technical and economic risk factors were also included to provide a more realistic estimate of STES market penetration. Results of MPM showed an initial penetration by 1990, with penetration rates greatest in Texas, California, Florida, and New Jersey. By the year 2000, a 76% penetration rate could be achieved, and 1.8 quads of energy saved annually. This figure increased to 6 quads by 2015, of which 2.2 quads would be natural gas and fuel oil energy savings.

Results of the STES Market Penetration Analysis are documented in Reference III-24. They include the effect of changes in cost assumptions and governmental incentives on market penetration, and were developed by running MPM for different percentage changes in ECR, and analytically relating these to changes in the input data parameters. Sensitivities are shown in the nomograph of Figure III-26. A 30% tax credit incentive was found to be particularly effective, in that the incentive could encourage some market penetration as early as 1985, and double the estimated market penetration by 1995, compared to the nominal case.

Figure III-26. STES Market Penetration Sensitivity

b. STES Applications in High Temperature Industries

The above studies of STES market penetration using a central receiver/heliostat configuration excluded eight industries whose major thermal energy needs involved temperatures in excess of 600°F. The specific industries were:

<u>SIC</u>	<u>Industry</u>
291	Petroleum refining
321	Flat glass
322	Glass and glassware, pressed or blown
324	Cement, hydraulic
325	Structural clay products
331	Blast furnace and basic steel products
332	Iron and steel foundries
333	Primary nonferrous metals

From Figure III-25, it is seen that the forecast energy use of the above high-temperature industries constitutes almost a third of the total energy use. It was therefore decided to analyze the processes within each industry and examine energy use by temperature range to determine the additional energy displacement which could be achieved by the introduction of STES. Since no hard data existed on the cost and performance of new system configurations employing second generation high-temperature technology, the study assumed the same STES configuration as the previous study, i.e., a tower-mounted central receiver with a heliostat collector field. It was also assumed that turbine waste heat could be supplied at 600°F, and that some thermal energy would be available directly from the receiver at temperatures up to 900°F for use by the industrial process.

The analysis of energy use indicated that of the eight high-temperature industries, only petroleum refining (SIC 291) and iron and steel foundries (SIC 332) had lower temperature processes whose energy requirements could be satisfied by the assumed STES concept. More advanced very high-temperature STES concept operating at peak temperatures of up to

4800°F have been postulated, but were not considered in this study. The contribution to STES market penetration was significant, especially in petroleum refining. As an example, the net effect by the year 2000 was to increase total STES energy displacement by 0.4 quads, or 21.1%. Detailed results of the study are contained in Reference III-25.

c. Field Survey of STES Potential Industrial Applications

As with any free enterprise system which offers a choice of alternatives, it is the customer and his investment criteria that ultimately determine the market and rate of market penetration. In the case of STES industrial applications, it was appropriate that the theoretical studies of market penetration be augmented by a field survey, in which some of the assumptions and relationships used in the analysis could be validated. The selection of firms to be visited in the field survey was based on a detailed market analysis. Data from this analysis had indicated that there would be STES market penetration for certain industry-state combinations by 1990. Both the amount of fuel displaced and the percentage market penetration were used as criteria in selecting preferred combinations. Once these had been selected, trade associations were contacted and marketing guides used to identify specific companies. Survey participants and their locations are listed in Table III-7; interviews were conducted in July and August of 1978.

Details of the survey are documented in Reference III-26. It should be noted that most of these firms were multinational in scope and reputation, with sales ranging from \$10 million to over \$6 billion per year. From a technical viewpoint, these companies can be characterized as large energy users, with daily electrical demands ranging from 2 to 50 MW, and operating continuously 24 hours a day, seven days per week. Three of the companies (C&H Sugar, Crown Zellerbach, and Colgate-Palmolive) already used cogeneration to supply much of their electrical needs, and were thus familiar with the total energy concept. Over half of the companies felt that there was little technical risk in adopting STES, and that a few years

Table III-7. Field Survey Participants (STES)

Industry	SIC	Company	Location State (City)	Management Level Briefed
Sugar Refining	2062	C&H Sugar	CA (Crockett)	VP, Operations
Paperboard Mills	2631	Crown Zellerbach	CA (Antioch)	VP, Operations
Plastics	2821	El Paso Products Rexene/Dart Ind Plastics Mfr Co	TX (Odessa) TX (Odessa) TX (Dallas)	VP, Technical Dir, Engineering VP, Engineering
Pharmaceuticals	2834	Pharmaceutical Co Squibb	NJ NJ (New Brunswick)	VP, Tech Oper Dir, Oper Plan
Soaps & Detergents	2841	Purex Colgate-Palmolive	CA (Lakewood) NJ (Jersey City)	Sr VP, Energy Dir, Engineering
Industrial Organic Chemicals	2869	Allied Chemical	CA (El Segundo)	Dir, Western Oper
Agricultural Chemicals	2874	Agric Fertilizer Co Occidental Petr	FL FL (White Springs)	VP, Manufacturing Dir, Research

of demonstrations in the field by large users would be sufficient for them to evaluate the STES performance. In the financial area, most of the companies used an investment criteria which required a minimum after-tax discounted cash flow internal rate of return on the order of 10 to 15%, which was consistent with the assumptions used in the market penetration analysis.

From an operational standpoint, land availability proved to be the most significant constraint to STES adoption. Half of the companies surveyed had no land available, and their five-year plans did not include any expansion at future sites. A few firms had new plants in areas other than those visited (North Carolina, Puerto Rico), and these might be more suitable in terms of land costs and availability.

The dozen firms interviewed in the field survey included only seven industries in four states, with a combined total energy use of 42 trillion Btu's annually. This represents only 0.3% of the total industrial energy use recorded in the 1974 Census of Manufactures, involving 1,945 industry/state combinations and over 300,000 industrial firms. The conclusions drawn from the field survey must therefore be regarded as trends and initial responses to exposure to STES concepts and requirements, rather than data having statistical significance. More specific surveys and design evaluations will be required to obtain the latter.

d. STES Evaluation Handbook

In the course of the field survey, industry executives and plant managers expressed considerable interest in the STES concept, and how STES might be applied to their own individual plant locations and needs. This interest became the basis for the development of a STES Handbook (Reference III-27). This handbook provides an analytic tool that can be used by industry to quickly assess the economics and performance of a specific STES application when employing a central receiver configuration. Inputs provided by the user include plant location, thermal and electric demand, and available land area and cost. With the aid of simple charts, tables and hand calculator, the user can determine investment requirements, financial viability, cash flow and fuel savings for any given year of STES implementation. The calculational procedures also facilitate the assessment of changes in government tax credit incentives or user rate of return criteria.

The sequence of decisions and computations which are presented in the Handbook appear in the flow chart of Figure III-27. The process begins with the user specifying the basic operating parameters of a proposed STES application, including annual thermal and electric demands, process heat temperature requirements, and desired electrical capacity. If the plant is below a minimum size, or outside of the temperature limits specified, then the STES configuration used in the Handbook does not apply and it is suggested that the user review other potential solar energy systems such as

Figure III-27. STES Computational Flowchart

distributed collectors. If the screening criteria are met, a thermal-to-electric ratio is computed and compared with a set of lower and upper limits. For $T/E < 1$, only a portion of the waste heat from the turbine/generator system can be utilized, and a solar electric system might be more effective than STES. For $T/E \geq 15$, the amount of electricity generated would be so small compared to the thermal needs, that a solar IPH system might be preferred, and the cost of a turbine/generator system eliminated. T/E values between these limits are accommodated in the performance table for STES. This table was generated from the performance relationships developed as part of the STES market penetration study discussed previously. In order to utilize this table, the daily direct normal insolation must be specified, and this can be obtained from a table or map furnished in the Handbook appendix which specifies this parameter as a function of plant location.

One of the performance parameters obtained from this table is the land area requirement for solar collectors. If sufficient land is available, then a full-sized STES can be considered, optimized to provide the best economic return. If this amount of land is not available, then the STES size is scaled down proportionately and the reduced parameter values used in the subsequent calculations. These must still meet the minimum plant size criteria. The next step in the process is to specify the user's financial parameters, and assume a start year in which STES will be operational. The latter is required because the cost of STES will be expected to decrease as the production level increases with time, while the costs of competing fuels are expected to increase. Once this is specified, the tables and graphs in the appendices can be used along with supplied equations to compute ACR, the annualized charge rate for STES, and ECR_M , the equivalent cost ratio. ECR_M is the basic measure of economic viability. If it is less than one, then the STES will be economic and provide more than the required rate of return when operating over its lifetime. If the ECR_M is greater than one, two options can be considered. The first is to select a later start year and repeat the computation. The second would be to calculate the effect of the user accepting a lower return on equity. A worksheet is provided to allow the ECR_M to be calculated for a number of iterations of this type.

Subsequent to the ECR_M computation, the internal rate of return is determined. A calculation is then made of the amount of fossil fuel which STES can displace. Equations, tables, and worksheets are next used to compute the cash flow on an annual basis. For those companies which prefer to use a before-tax gross payback period as a measure of the worth of an investment, a technique for calculating this quantity is also presented. Since the STES costs and fuel price inputs to the tables and graphs are in 1977 dollars, the values of capital investment requirements and cash flow are also in 1977 dollars. A table is also provided which allows conversion to current dollars, i.e., the year in which the Handbook is utilized for computations.

2. SOLAR THERMAL SMALL POWER PLANTS

A study of small solar thermal power systems was initiated in 1977 to determine the conditions under which these systems could be cost-effective sources of electric power for utility and industrial applications, using electrical generators of no more than 10 MWe rated capacity. The approach involved the accumulation of a national data base characterizing existing generating units, cost tradeoff analyses involving both repowering and replacement, and the development and application of a technique for determining potential market penetration, as discussed in the paragraphs below.

a. Data Base Development

The first phase of the study, documented in Reference III-28, developed data on size distribution of generator units by type for small utilities, extracted from the Electrical World Directory of Electric Utilities. Some data was also compiled on solar system costs for a central receiver configuration and financial variables appropriate to a small utility economic analysis.

In the next phases of the study, the data base on utility systems was considerably expanded. These data were developed from combining a Federal Energy Administration report and the Electrical World Directory of Electric Utilities. Where a discrepancy existed between the two sources with respect to a specific utility, the utility was contacted by telephone to resolve the discrepancy. This effort culminated in the preparation of an inventory of small generating units in each of the 50 states. The inventory for each state listed the name of each utility system with small generating units; indicated whether the utility is investor-owned, municipal, or other (normally, an electric cooperative); and listed the number and sizes of each steam turbine, diesel generator, and gas turbine in each utility. All of this information was published in Reference III-29. In addition, the report summarized the data for each state in terms of the number of utility systems, generating units, and generating capacity. Figure III-28 summarizes statistics derived from the survey for small generating units in the United States, and shows the location of the 25 states with the largest number of small generating units. Although not included in Reference III-29, data was also gathered on the age of each unit (where available) for subsequent use in market penetration analyses. It is seen from the survey that the maximum potential of solar small power systems (≤ 10 MWe) in the utility market is almost 8000 MWe of capacity.

Two sample surveys of small utilities were conducted to determine potential growth in this market, and attitudes toward solar. The first of these involved 14 utilities in Arizona, New Mexico, and Texas (Reference III-30). It was found that except for those systems completely isolated from the U.S. power grid, future increases in demand would largely be met by purchasing additional power from current suppliers. There also appeared to be a trend toward forming joint ventures and building large coal-fired plants. As for solar versus conventional powering, the primary criterion would be relative cost. These results were confirmed in a second survey involving 48 utilities in 16 western states (Reference III-31).

TYPE OF UNIT	NUMBER	PERCENT	CAPACITY, MW _e	AVE POWER, MW _e
STEAM-ELECTRIC	581	15.0	2947.3	5.07
DIESEL GENERATOR	3243	83.8	4724.6	1.46
GAS TURBINE	45	1.2	221.6	4.92
TOTAL	3869	100	7893.5	2.04

Figure III-28. Geographic Distribution of Utility Small Power Units

A data base for the industrial small power systems market was obtained by screening data from the Energy Information Agency in the U.S. Department of Energy to select systems less than 10 MWe in rated capacity. These data were compiled originally by the Federal Power Commission as part of the Form 4 Industrial Ledger and Form 12-C Ledger for 1976. The inventory is documented in Reference III-32, and summarized in Figure III-29. The potential industrial market is only one-quarter of the size of the utility market discussed previously.

The industrial data base was also supplemented by a sample survey involving 36 companies operating 48 plants in the western United States (Reference III-31). In general, these plants generated two-thirds of their power, operated 24 hours per day, seven days per week, and burned natural gas as their primary fuel. Most of those interviewed said that competitive system costs and reliability would be primary requirements before they would consider solar-powered electric systems, and quoted requirements on payback period for capital equipment projects ranging from 1-10 years, with an average period between 6 and 7 years.

b. Cost Tradeoff Studies

Based on the capital cost data shown in Table III-8, a preliminary breakeven cost analysis of solar thermal and oil- and gas-fired, steam-electric and diesel plants of 1 MWe and 10 MWe capacity in hypothetical utility applications was conducted for the five southwestern states of Arizona, California, Nevada, New Mexico, and Texas, which have the highest insolation levels in the U.S. Variables considered in this analysis included the type of ownership (municipal or investor-owned), solar plant operational mode (repowering and replacement), heliostat cost (\$50, \$70, \$140, and \$210 per square meter), and startup date for the solar thermal power plants (1985 and 2000). Insolation data and forecast levelized fuel costs used in the analysis were the same as those used in the previous STES studies, as documented in Reference III-15 and III-17, respectively.

TYPE OF UNIT	NUMBER	PERCENT	CAPACITY, MW _e	AVE POWER, MW _e
STEAM-ELECTRIC	477	65.3	1765.7	3.70
DIESEL GENERATOR	251	34.4	336.5	1.34
GAS TURBINE	2	0.3	9.0	4.50
TOTAL	730	100.0	2111.2	2.89

Figure III-29. Percentage Distribution of Industrial Small Power Systems

Table III-8. Capital Cost Assumptions for Breakeven Cost Analysis

SYSTEM	COST (1977 \$/kW _e)	
	1 MW _e	10 MW _e
SOLAR CENTRAL RECEIVER ^a		
REPOWERING MODE	2734	1285
REPLACEMENT MODE	5032	2230
STEAM - ELECTRIC	2600	1132
DIESEL	400	300

^a No storage, heliostat cost goal = \$70/m².

The small solar thermal power systems were examined for two operational modes, repowering and replacement. In the repowering mode, the solar power system provides thermal energy during periods of acceptable insolation to the steam turbine of a conventional steam-electric plant, as well as to a thermal storage system. (In these initial repowering and replacement analyses, the solar thermal power plant was sized for "zero" storage to minimize capital costs.) Whenever the insolation is too low, the steam-electric plant generates its own power by burning fossil fuel. In the repowering mode, the solar power system costs include the solar collectors (heliostats), receivers, controls, and associated piping and valves. In the replacement mode, the power conversion equipment, i.e., turbine-generators, must also be purchased for the solar thermal power system. Repowering would be the preferred operational mode for a steam-electric plant which already has the power conversion equipment. Replacement would be the required

operational mode for a diesel generator, which does not use turbine generators. Whenever the insolation is too low for operation of the solar thermal power system, the diesel generator would be turned on to produce electrical power.

Results of the systems cost comparison were developed in terms of relative busbar energy cost for 1985, and are documented in Reference III-30. Effects of insolation, system size, and operating mode are shown in Figure III-30. It is seen that the economy of scale associated with increasing plant size is the most dominant variable examined. A one MWe solar plant is more cost-effective than steam-electric in only two regions, while a 10 MWe plant is more cost-effective in all five regions. Repowering is also seen to be always more cost-effective than replacement for a solar thermal power plant. In addition, repowering is only about two-thirds as sensitive to decreases in the solar insolation level as replacement. The decreased sensitivity results from the fact that repowering does not involve the purchase of the turbogenerating equipment, which is very expensive in the range of power examined in this study and is of the same order of magnitude as the fuel costs over the 30-year plant life.

As part of the study of Reference III-30, DOD utility systems were also examined as a potential generic class of user for small power systems. However, only one Army base and nine Navy bases generate all of their own power; 19 other Navy installations generate part of their power. Northwest Guam Air Force Base was investigated as a site for an experimental solar thermal power system since it generates power for a satellite tracking station with large diesel generators. Although there is land available to install a solar thermal power system, insolation data acquired in June of 1978 indicated that the insolation is approximately equivalent to Miami, which is lower than anticipated.

Figure III-30. Results of Cost-Effectiveness Analyses

c. Market Penetration

The methodology used to develop market penetration forecasts for solar small power systems was similar to that previously employed in evaluating solar total energy systems. The data bases were the characteristics of the individual utility and industrial units of References III-29 and III-32. A penetration probability was calculated for each unit, based on its equivalent cost ratio (ECR), i.e., the ratio of the annualized cost of solar to the annualized cost of the energy which it would displace. The ECR's calculated for each unit were optimized by computer simulations, in which the size of the collector and amount of storage were varied to determine the lowest ECR. In the repowering mode, the energy cost was that of the displaced fuel, while for the replacement mode it was the cost of purchased electricity.

The product of the unit rated capacity and the penetration probabilities were aggregated by state and nationally to determine the market penetration, and this process was repeated at five-year time intervals from 1985 through 2015. A ranking was also obtained of the penetration probabilities, which would be useful in contacting potential solar users. A sample printout for the utility repowering market is shown in Figure III-31. In the ECR calculations, the insolation data base and forecasts of energy prices were the same as those used previously (Ref. III-5 and III-17), but an updated set of solar central receiver capital costs was developed as a function of unit size and time period, based on a composite of study results by Battelle, JPL, and SERI. The cost of a 10 MWe baseline solar thermal power plant in the repowering mode at 1990 production levels was assumed to be \$3642/kW, with corresponding heliostat costs of \$100/m². Details of the data inputs, methodology and market penetration study results are given in Reference III-31.

STATE	CITY	UTILITY	OWN	STATUS	NPLANT	MSIZE (KW)	TYPE	NYEAR	PROB	PEN (KW)
NM	RATON	RATON PUBLIC SERVICE CO.	M	0	1	6600	S	1962	.3136	2069.63
KS	WINFIELD	WINFIELD MUNICIPAL ELECTRIC LIGHT DEPT.	M	0	1	10000	S	1957	.0885	884.68
KS	MC PHERSON	MC PHERSON BOARD OF PUBLIC UTILITIES	M	0	1	10000	S	1957	.0885	884.68
KS	WELLINGTON	WELLINGTON MUNICIPAL UTILITIES	M	0	1	7500	S	1956	.0452	338.72
TX	GARLAND	GARLAND ELECTRIC DEPT.	M	0	2	8500	S	1957	.0419	712.72
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	7500	S	1958	.0308	231.29
NS	SCHUYLER	SCHUYLER DEPARTMENT OF UTILITIES	M	0	1	5000	S	1958	.0167	83.38
TX		TEXAS A&M UNIVERSITY	O	0	1	5000	S	1958	.0153	76.41
MN	HIBBING	HIBBING PUBLIC UTILITIES COMMISSION	M	0	1	10000	S	1965	.0134	133.54
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	2	5000	S	1965A	.0134	133.83
HI		HAWAIIAN ELECTRIC CO., INC.	I	0	1	4925	S	1974	.0128	62.85
MO	FULTON	FULTON BOARD OF PUBLIC WORKS	M	0	1	6000	S	1959	.0107	64.09
IA	WEBSTER CITY	WEBSTER CITY MUNICIPAL LIGHT & POWER	M	0	1	7500	S	1960	.0094	70.16
IA	SPENCER	SPENCER MUNICIPAL UTILITIES	M	0	1	7500	S	1960	.0094	70.16
IA	MT. PLEASANT	MT. PLEASANT UTILITIES	M	0	1	7500	S	1966	.0094	70.16
IA		CENTRAL IOWA POWER COOPERATIVE	O	0	1	8000	S	1957	.0079	63.18
MN	WILLMAR	WILLMAR MUNICIPAL UTILITIES COMM.	M	0	1	7500	S	1956	.0045	33.80
IA		IOWA STATE UNIVERSITY	O	0	1	6000	S	1961	.0044	26.53
IA	ATLANTIC	ATLANTIC MUNICIPAL UTILITIES	M	0	1	5000	S	1958	.0019	9.52
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	10000	S	1967	.0017	16.68
MN	NEW ULM	NEW ULM PUBLIC UTILITIES COMMISSION	M	0	1	6000	S	1957	.0015	9.01
MI	GRAND HAVEN	GRAND HAVEN BOARD OF LIGHT & POWER	M	0	2	10000	S	1961	.0011	22.34
IL	WINNETKA	WINNETKA WATER & ELECTRIC DEPT.	M	0	1	10000	S	1960	.0011	11.07
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	7500	S	1956A	.0010	7.75
OH	PAINESVILLE	PAINESVILLE ELECTRIC DIVISION	M	0	2	7500	S	1956A	.0010	15.50
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	7500	S	1956A	.0010	7.75
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7500	S	1956A	.0010	7.75
WI	MENASHA	MENASHA ELECTRIC & WATER UTILITIES	M	0	1	8975	S	1956	.0009	8.33
OH	COLUMBUS	COLUMBUS, DIVISION OF ELECTRICITY	M	0	1	7000	S	1956A	.0009	6.21
IN	WASHINGTON	WASHINGTON LIGHT & POWER DEPT.	M	0	2	5000	S	1957	.0009	8.97
MD	HAGERSTOWN	HAGERSTOWN MUNICIPAL ELECTRIC LIGHT PLAN	M	0	2	10000	S	1960A	.0007	13.57
OH	SHELLY	SHELLY MUNICIPAL ELECTRIC PLANT	M	0	1	6000	S	1956A	.0006	3.41
OH	ST. MARY'S	ST. MARY'S MUNICIPAL LIGHT & POWER	M	0	1	6000	S	1957	.0006	3.41
MN	SPRINGFIELD	SPRINGFIELD PUBLIC UTILITIES	M	0	1	4000	S	1960	.0006	2.53
IL	PERU	PERU LIGHT DEPT.	M	0	1	8000	S	1960	.0006	5.11
WI	RICHLAND	RICHLAND CENTER MUNICIPAL UTILITIES	M	0	1	7500	S	1966	.0005	3.86
NC		UNIVERSITY OF NORTH CAROLINA	O	0	1	10000	S	1961A	.0005	5.39
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	3	7500	S	1955A	.0005	10.47
FL	KEY WEST	KEY WEST UTILITY BOARD	M	0	2	5000	S	1957A	.0003	2.96
OH	ORVILLE	ORVILLE MUNICIPAL UTILITIES	M	0	1	5000	S	1956A	.0002	1.02
MI		MICHIGAN STATE UNIVERSITY	O	0	1	6000	S	1958	.0002	1.04
LA	NATCHITOCHES	NATCHITOCHES MUNICIPAL ELECTRIC LIGHT &	M	0	1	6250	S	1962	.0001	.66
LA	MORGAN CITY	MORGAN CITY MUNICIPAL ELECTRIC PLANTS	M	0	2	6250	S	1963	.0001	1.32
IL	HIGHLAND	HIGHLAND ELECTRIC LIGHT DEPT.	M	0	1	6000	S	1961	.0001	.40
LA	MONROE	MONROE UTILITIES COMMISSION	M	0	1	6000	S	1955A	0.0000	.16

Figure III-31. Example of Individual Utility Plant Rankings Based on SSPS Repowering Mode Adoption Probability

Figure III-32 shows the expected penetration of the 7930 MWe utility market. The curves correspond to a 2% penetration by 1990, increasing to 14% by 2015. These are maximum values, subject to verification of land availability, insolation, fuel costs, and financial assumptions. Earliest penetration is expected for municipal utility repowering, followed by later growth in the replacement market segment. Additional data from the study indicate that the equivalent fuel displacement by the year 2000 is on the order of 13.7 trillion BTU annually, and that the highest penetration probabilities are assigned to utilities in Arizona, Hawaii, Kansas, and New Mexico.

Figure III-32. Utility System Market Penetration

It is clear from the above that an increase in market penetration of solar small power systems which will contribute substantially to national energy objectives will require a commercialization strategy involving substantial government aid. A set of sensitivity studies was therefore made using the market penetration model, and sample results are shown for investor-owned utilities in the nomograph of Figure III-33. As an example, an increase in tax credit from 10% to 30% (which reduces ECR by 32%) results in an increase in the year 2000 penetration by a factor of 5 (from 80 MWe to 400 MWe). The nomograph can also be used to evaluate other effects such as increasing fuel prices, or reductions in O&M costs.

Figure III-33. Impact of Cost Variation on Market Penetration of Investor-Owned Utilities

A similar analysis was made of the expected penetration of the 2111 MWe industrial market (which includes industrial plants, government facilities, and universities). Because the data base did not provide the installation date of the conventional power system, there is no criterion for deciding when a conventional, fossil-fueled power system is to be shifted from the repowering category to the replacement category.

Therefore, the penetration analysis first considered all conventional power systems for replacement during the 30-year period from 1985 to 2015 and then considered all systems for repowering during this same period. Figure III-34 shows cumulative market penetration for the repowering and replacement categories. The capacity displaced for repowering applications commences earlier and is considerably greater than that for replacement applications. Therefore, repowering applications should be favored in subsequent investigations in order to gain earlier access to the industrial market and to capture the largest possible fraction of the available market. Nonetheless, the capture ratio is quite small even at the year 2015 where only five percent of the available market is penetrated.

Figure III-34. Industrial Market Penetration

The aforementioned results are not additive because steam turbines are found in both categories. However, the diesel and gas turbine systems in the replacement category can be summed with the repowered steam turbine systems.* This increment is very small and adds only about 4 MWe to the cumulative displaced capacity in 2015. Favorable market penetration was predicted for repowering applications in Arizona, California, Hawaii, and New Mexico. Although not located in these particular states, a number of federal government power systems also ranked relatively high in expected penetration when compared with installations at industrial sites.

3. SOLAR-POWERED IRRIGATION SYSTEMS

A study was initiated in March of 1977 to determine the technical and economic feasibility and the potential market within the agricultural community for solar thermal power systems designed for pumping water with a possibility of meeting other farm power needs. Irrigated crops are estimated to amount to 14 percent of all export crop values. Potential loss of the irrigated crop production sector, due to rising prices and possible shortages of conventional energy sources, would have a significant (\$2-3 billion) impact on the nation's balance of trade and on local economies. Emphasis was placed on examining the prospects for early entry of dispersed solar thermal systems into the irrigation power market. An additional purpose was to estimate the impact of government economic incentives on this market potential. An extensive data base was developed on irrigation energy demand, and combined with solar system characteristics to explore economic tradeoffs.

The choice of the solar-powered irrigation system design concept was restricted to a system that was typical of existing and planned experimental solar irrigation facilities. This concept was based on a field of distributed, single-axis tracking, parabolic trough collectors which provided heated working fluid to a Rankine-cycle turbine generator that delivered electrical power to an irrigation pump. Thermal storage was

assumed to stabilize and extend the solar irrigation system daily operational period. A provision for seasonal water storage was included in the analysis to determine its effect on system performance and lifetime costs. Standby electric power from a local utility was retained as an option.

a. Data Base Development

With the aid of two dozen contacts and consultants at various state universities and the Department of Agriculture, data was developed on a county-by-county basis listing acreage by crop, irrigation requirements, pumping depth, power unit distributions, and type of water sources (ground or surface). A computer program was developed to compute energy demand profiles by month for input to solar tradeoff studies, and to aggregate the data to obtain total market potential. The data base and associated programs are documented in References III-33 and III-34. A screening process was employed to determine the geographic region where solar irrigation systems would be most concentrated. It is seen from Figure III-35 that the 17 western states (comprising the Pacific, Mountain, Northern Plains, and Southern Plains regions) account for 83% of the nations irrigated cropland, and because of deepwell locations, they consume 93% of the irrigation energy. Since they also represent the higher insolation regions of the country, the 17 western states were the only ones contained in the computerized data base.

The county data was aggregated by state to develop the irrigation market energy demand for pumping groundwater, and is summarized in Table III-9 by state for three cases: (a) energy delivered to pump drive unit (all pumps driven by electric motors); (b) energy delivered to pump drive unit (drive units conform to the current mix of petroleum and natural gas-fueled engines and electric motors); (c) energy delivered in the form of fuel to engine-driven pumps and to electric-generating utilities. Overall, 346×10^{12} Btu of irrigation energy in fossil fuels is required just for

Figure III-35. National Distribution of Irrigated Acreage Percent of Total U.S. Pumped Irrigation by Farm Production Region.

Table III-9. Irrigation Energy Market Demand Summary (Groundwater Sources)

STATE	ENERGY DEMAND		
	MOTOR-DRIVEN PUMPS (10^9 kWh)	ENGINE- AND MOTOR-DRIVEN PUMPS (10^9 kWh equiv.)	FUEL ENERGY (10^{12} Btu)
ARIZONA	3.38	7.15	42.4
CALIFORNIA	4.91	5.27	54.5
COLORADO	1.04	2.12	12.8
IDAHO	3.58	4.07	40.0
KANSAS	1.37	5.40	20.2
MONTANA	0.32	0.36	3.5
NEBRASKA	1.64	5.49	22.1
NEVADA	0.13	0.21	1.5
NEW MEXICO	1.31	4.54	18.5
NORTH DAKOTA	0.07	0.12	0.8
OKLAHOMA	0.71	2.58	10.2
OREGON	0.95	0.95	10.4
SOUTH DAKOTA	0.10	0.30	1.3
TEXAS	6.25	22.11	89.7
UTAH	0.36	0.50	4.1
WASHINGTON	1.00	1.00	11.0
WYOMING	0.29	0.42	3.3
TOTAL	27.41	62.59	346.3

pumping groundwater supplies. An additional 142×10^{12} Btu is required for surface water pumping, resulting in a grand total of 488×10^{12} Btu, using a 1969 data base for irrigated acreage. Continued growth in this acreage can be expected to result in increased irrigation energy expenditures out to 1985. After the time, limitations in land and water availability would be expected to slow this growth, exclusive of any negative impact from increased costs of energy or curtailment of energy supplies.

b. Analysis of Market Penetration

A comparative analysis of Solar Irrigation Systems (SIS) was made using the simulation model previously used for total energy and small power systems analysis, suitably modified to reflect SIS parabolic trough performance and cost characteristics. Collector area, turbine-generator size, thermal storage and water storage were systematically varied in a solar tradeoff study to determine an optimum configuration. Optimization was based on minimizing the equivalent cost ratio (ECR), i.e., the ratio of the annualized cost of SIS to the annualized cost of the displaced conventional energy. The latter was obtained from special price forecasts developed on a county-by-county basis for the leading agricultural states by Sherman H. Clark Associates, and documented in Reference III-35.

The analyses included three operational strategies; a basic system with high temperature storage, a system where water can be pumped into a reservoir during the off-peak season and withdrawn during peak irrigation months, and a strategy in which excess solar generated electric energy is sold back to the utilities. Two specific applications were modeled; an alfalfa farm in Arizona, and a corn crop in Nebraska. These offered interesting contrasts in growing season, insolation characteristics, irrigation methods, and irrigation well depth. Another parameter which was varied was ownership, since the financial characteristics used in computing SIS annualized costs were quite different for small, medium, and large farms, and electric cooperatives.

Detailed results are discussed in Reference III-34. A sample demand pattern for a small alfalfa farm using the sell-back strategy is shown in Figure III-36. This strategy gave the lowest ECR (1.33) and effectively provided complete energy displacement, since the energy purchased in the peak months is balanced by the sell-back during the off-season period.

Figure III-36. SIS Energy Balance and System Economics, 80kW_e Turbine, Sell-Back Strategy

Using a strategy of meeting a level energy demand year round and a corresponding baseline solar cost of \$4700/kW_e for an 80 kW_e unit in 1985, ECR's were calculated for each of the 17 western states. Results were plotted in terms of the reduction in baseline solar cost required to achieve breakeven costs (ECR=1) and SIS market penetration in each state. Figure III-37 shows the cumulative effect of the cost goal reduction for small and large farms. It is seen that the large-farm market starts to become

available if solar irrigation system costs can be reduced to 94% of the estimated \$4700/kW_e baseline system costs, whereas costs for small-farms must drop to 80% of the baseline figure. Approximately 60% of the market would become available to solar irrigation systems, if system costs were to decrease to 40% of the baseline cost for small-farm applications and to 50% for large-farm applications.

Figure III-37. Solar Irrigation System Market Potential for Small and Large Farms

Arizona, California, Kansas, New Mexico, Nebraska, and Texas were found to be leading candidates for solar irrigation system installation on the basis of (a) high levels of insolation, (b) large expenditures of energy for irrigation purposes, and (c) prospects for rising fuel costs. These states account for 85% of the total irrigation energy consumed in the 17 western states. Based on comparative cost analyses, the first irrigation market available for penetration in 1985 by solar power systems would include large farms in southeastern Arizona. This area consumes approximately 1.5% of total irrigation energy in the 17 western states. Cost-effective regions in the other five states, representing approximately 30% of total irrigation requirements of the western states, are next in ranking.

Government economic incentives would permit a significant relaxation of the cost reductions required to make a solar irrigation system competitive with conventional energy sources. Excluding effects of inflation either a rebate of solar irrigation system property taxes, a 20% investment tax credit, or an interest-free loan could open the large-farm markets to solar irrigation systems without cost reductions from the baseline estimate. Small farms cannot generally take advantage of the investment tax credit, but interest-free loans could place them on a financial par with large farms. If solar irrigation system capital costs were to be reduced to 60% of the baseline costs by the year 2000, and if interest-free loans were to be applied to this expenditure, then 60% of the irrigation market would be available for penetration. Since the total irrigation market was estimated as 0.49 quads (groundwater plus surface water pumping), this would correspond to a total fuel displacement of 0.29 quads annually, or 145,000 barrels of oil per day.

C. SPECIAL STUDIES IN ADVANCED TECHNOLOGY

A number of studies were undertaken at the request of ERDA and DOE to examine the cost and/or market potential implications of the use of advanced solar technologies. Areas which were examined included advanced storage techniques (both dedicated and shared), high temperature solar industrial process heat applications, and solar fuels and chemicals production. These are discussed in the paragraph below.

1. ADVANCED STORAGE SYSTEMS

Storage capacity is an important parameter in the design of advanced solar plants since it provides flexibility for dispatching solar plants and enhances the plant capacity factor and economic worth to the utilities. Because of the importance of storage study efforts have been directed towards applications and requirement analyses of two generic classes of storage systems. These have included on-site storage located at each solar plant site and utility system shared central storage.

a. On-site Storage

Two issues are of particular concern for on-site storage; sizing of storage capacity to minimize overall solar plant costs and the impact of storage performance on plant operations. The former issue was addressed in the large power system studies described in Section IIIA of this report. The latter was investigated in a parametric study of both current technology and advanced systems, and is documented in Reference III-19.

Figure III-38 shows the impact of varying the storage performance characteristics on the electric production costs of a reference system. The curves on the left show the improvement in power conversion efficiency as the storage design is improved in terms of its steam conditions at the turbine inlet. The curves on the right have been developed utilizing a

solar plant simulation model for various water-steam and liquid sodium storage designs. The simulation was conducted for an Inyokern site for projected utility load characteristics beginning in 1990. Other assumptions are outlined in the figure. Cost of storage was varied parametrically. The resulting energy costs were normalized with respect to that of the reference system cost. These curves show percent improvements in the energy production cost of a solar plant as a function of storage subsystem or turbine performance and unit costs. Similar analyses for Brayton solid-gas storage are documented in Reference III-19.

ASSUMPTIONS

- CURRENT TECHNOLOGY WATER-STEAM AND LIQUID SODIUM SYSTEMS ANALYSED
- 100 MW_e PLANTS, 6 HOUR STORAGE, 0.41 PLANT CAPACITY FACTOR
- STORAGE EFFICIENCY 0.85
- O&M COSTS ASSUMED SAME FOR ALL SYSTEMS
- WATER-STEAM SYSTEM
 - POWER CONVERSION EFFICIENCIES
 - $\eta_{PR} = 0.35$ (receiver operation)
 - $\eta_{PS} = 0.27$ (storage operation)
 - VARIABLES
 - STORAGE STEAM CONDITIONS
 - STORAGE COST

- LIQUID SODIUM SYSTEMS
 - SODIUM COOLED RECEIVER, SODIUM STORAGE
 - STEAM REHEAT CYCLE
 - $\eta_{PR} = \eta_{PS}$
 - VARIABLES
 - TURBINE INLET STEAM CONDITIONS
 - SODIUM EQUIPMENT COST

Figure III-38. Impact of Storage Characteristics on Steam Rankine System Effectiveness

b. Shared Storage Systems

A shared storage system is one that can be charged by both solar and conventional power generation plants, and discharged as appropriate to meet the total system demand. This concept, shown in Figure III-39(a), employs the principle of load leveling to improve the economics of the utility. In Figure III-39(b), the hatched area in the trough of the daily demand profile of a typical utility corresponds to energy that is used to charge storage when it is relatively inexpensive to do so. The hatched area in the peak of the demand profile corresponds to the energy that is extracted from storage. When the "load is leveled" in this manner, some of the peaking units with high operating cost can be retired, resulting in a net cost saving (but sometimes with increased fuel usage).

An example of some of the results of the shared storage systems analyses is shown in Figure III-39(c). Cost and fuel savings are measured from a reference system comprised of conventional power plants without storage. The savings that can be achieved by operating in a load leveling mode by means of centralized energy storage such as pumped hydroelectric are labeled "no solar - load leveling only". In this case, \$4810 per megawatt-hour of storage capacity per year in operating costs are saved. This amount is theoretically available to be spent for the storage subsystem. Since projected annual costs of many storage devices fall below this level, it can be concluded that load leveling alone is a viable concept from a cost standpoint. However, it is seen that fuel is not saved for this case; in fact, 1.02 million million additional Btu's of fuel are required to compensate for the efficiency losses of the storage system.

Figure III-39. Storage Application Analyses

For comparison, three cases of solar augmented load leveling (shared storage) are shown for comparison. The cost of electrical energy produced by the solar plant is varied parametrically for each case as shown. The results show that utility operating cost savings are still achievable and, furthermore, that there are net fuel savings as well. Detailed results are given in Reference III-19. In summary, the studies indicate that the shared storage concept works to the mutual benefit of the solar plant-utility system. It can provide cost and fuel savings that are otherwise not attainable from energy storage systems separately dedicated to the solar plants.

2. MID AND HIGH TEMPERATURE INDUSTRIAL PROCESS HEAT (IPH)

As part of a continuing review and evaluation of the total Solar Thermal Power systems Program, a number of potentially attractive new applications of solar thermal technology were identified in mid-1977 which warranted more detailed examination. One of these possible applications involved the production of mid-and high-temperature industrial process heat from solar energy, with emphasis on those applications which might be served by solar thermal technology developed for large scale power production. Whereas previous systems studies involved detailed simulation, cost tradeoffs and market penetration forecasting, the emphasis in this study was to size the market potential, identify promising applications, and determine future program needs through surveys and interviews with user segments of the industry.

The study began with a review of industrial energy use. The industrial process heat market was found to be approximately 27% of the 69×10^{15} BTU's (i.e., 69 quads) total U.S. energy consumption in 1971. The estimated 1977 annual energy consumption was projected to be approximately 80 quads, consistent with a 2.4% annual growth rate. The breakdown of 1971 net energy consumption by market sector is shown in Figure III-40(a). Industry consumed approximately 40% of the total consumption (including purchased fuels plus electricity). Process steam and direct process heat comprised 68.4% of the industrial consumption.

Figure III-40(b) summarizes the distribution of process heat temperature requirements based upon a review of several recent studies. These data suggest that the Low-Temperature Industrial Process Heat Program, which is scoped to deliver thermal energy at or below 350°F using flat plate or low concentrator collector technology can satisfy approximately 22%

of industrial process heat requirements. The figure implies that the next 33% (i.e., 22 to 55 percent) of industrial process heat requirements fall in the 350°F to over 2000°F range and can be satisfied utilizing technology now developed for the generation of electric power.

Figure III-40. Industrial Energy Consumption

Five two-digit standard industrial classifications (SIC) groups account for about 75% of the industrial sector's total energy use, mostly in the form of process heat at temperatures above 350°F. These five groups are Paper and Allied Products, Chemicals, Petroleum Products, Stone, Clay and Glass, and Primary Metals. Histories of their energy use are shown in Figure III-41 (with cement split out separately from the stone, clay and glass category). Studies of these groups were performed and documented in two phases; a technology assessment phase covering chemicals, petroleum and cement (Reference III-36), and a field survey covering the remainder of the groups (Reference III-37). Highlights from these studies are presented in the paragraphs below.

Figure III-41. 1967-1976 Annual Energy Consumption (in quads) of Five Largest Energy - Using Industries

a. Technology Assessment

A review of the existing and planned hardware suitable for solar IPH applications indicated a basic division into distributed parabolic troughs and dishes for medium temperature applications, central receivers and distributed dishes for high temperature use, and hot air (Brayton cycle) concepts and ceramic receivers for very high temperatures. An illustrative application was therefore selected for study in each of the medium-, high-, and very high-temperature process heat ranges. These applications were:

- Crude Oil Tank Farm Heating (350°F - 550°F)
- Petrochemical/Refinery Steam Plant (550°F - 1000°F)
- Cement Manufacture (1500°F - 2000°F)

Each of these applications is currently served by fossil-fueled process heat systems and represents a candidate for solar thermal process heat systems.

(1) Tank Farm Heating

A tank farm heater such as the one sketched in Figure III-42 might be used to heat crude oil to obtain a proper viscosity for moving and processing the fluid. Typically there is adequate area above the tank and inside the emergency containment levy for collection of sufficient solar energy. A second advantage of the tank farm application is that the latent heat of the liquid stored in the tank provides a natural energy storage mechanism. Furthermore, a tank heating system is already installed at typical refineries which could be used during periods of extended bad weather or in the evenings to reduce temperature fluctuations.

Figure III-42. Supplemental Solar Steam Tank Farm - Crude Oil Asphalt Storage

Assuming a minimum of two solar tank heating units per refinery, a review of refineries located in medium-to-high insolation areas indicated a potential market of over 100 units, with an additional 55 units usable at cement plants which require tanks for storing their primary or back-up fuel. Discussions with Continental Oil Company (see Reference III-36) and subsequent calculations indicate that the combined market might total 0.3 trillion Btu's annually. Penetration of this market would depend upon the production level of solar systems and the cost of competing fuels.

(2) Steam Plants

Refineries or chemical plants typically require a combination of process heat, process steam and pumping energy. Most existing steam plants at refineries or chemical plants are now gas- or oil-fired. Steam temperatures of 750°F and pressures around 650 psig for 24 hr/day, 365 day/yr are typical of refinery use. Table III-10 lists capacity and estimated steam requirements for major refineries in the higher insolation regions. Analysis indicates that a solar collector of the central receiver configuration (with six hours of storage) could displace 35 to 45% of the fuel required for steam generation and thus represents a sizable potential market. A preliminary estimate of conventional versus solar annualized costs using present worth methodology for several assumed equipment life cycle periods is documented in Appendix C of Reference III-36 and suggests that solar process steam plants could become economic in the late 1980's or 1990's.

(3) Cement Plants

In 1962 there were 170 portland cement plants in the United States. In the U.S., high shipping costs, local market size, and large distances between market areas dictate that plant size be limited to that plant

Table III-10. Petroleum Refineries

COMPANY AND LOCATION	CRUDE CAPACITY (B/CD)	ESTIMATED STEAM CAPACITY (MW _t)
CALIFORNIA		
ATLANTIC RICHFIELD CO., WATSON	93,000	454
GULF OIL, SANTA FE SPRINGS	21,900	132
MOBIL OIL, TORRANCE	95,000	338
SHELL OIL, WILMINGTON	50,000	236
STANDARD OIL, EL SEGUNDO	120,000	550
UNION OIL, GRANDE	1,500	96
UNION OIL, RODEO	37,000	165
UNION OIL, WILMINGTON	83,000	286
KANSAS		
AMERICAN OIL, NEODESHA		85
CRA, INC, COFFEYVILLE	8,000	85
MOBIL OIL, AUGUSTA	17,000	132
NATL. COOP. REF., McPHERSON		121
PHILLIPS PET., KANSAS CITY	15,000	234
SKELLY OIL, EL DORADO	20,000	179
OKLAHOMA		
CHAMPLIN PET., ENID	22,000	102
CONTINENTAL OIL, PONCA CITY	13,000	217
SEQUOIA REFINING, PONCA CITY	10,500	96
SUN OIL, DUNCAN	17,000	126
SUN OIL, TULSA	31,500	245
TEXACO, WEST TULSA	13,500	129
TEXAS		
AMERICAN OIL, TEXAS CITY	70,000	663
ATLANTIC RICHFIELD, HOUSTON	70,000	605
BP OIL CORP., PORT ARTHUR	28,000	220
CHEVRON OIL, WESTERN DIV., EL PASO	24,600	179
COASTAL STATES PETROCHEMICAL, CORPUS CHRISTI	33,000	365
COSDEN OIL & CHEM., BIG SPRING	25,000	151
CROWN CENTRAL PET., PASADENA	38,000	231
DIAMOND SHAMROCK, SUNRAY	12,000	104
GULF OIL, PORT ARTHUR	158,100	904
HESS OIL & CHEM., CORPUS CHRISTI	-	129
HUMBLE OIL, BAYTOWN	149,000	948
MARATHON OIL, TEXAS CITY	20,000	118
MOBIL OIL, BEAUMONT	103,000	866
PHILLIPS PET., BORGER	-	234
PHILLIPS PET., SWEENEY	-	234
PONTIAC REF., CORPUS CHRISTI	7,000	146
SHELL OIL, DEER PARK (Houston)	64,400	445
SIGNAL OIL, HOUSTON	21,000	198
SOUTHWESTERN OIL, CORPUS CHRISTI	9,000	143
SUNTIDE REF., CORPUS CHRISTI	10,000	135
TEXACO, PORT ARTHUR	108,000	852
TEXACO, PORT NECHES	22,000	124
TEXAS CITY REF., TEXAS CITY	14,500	137
UNION OIL OF CALIF., NEDERLAND	39,000	288
UTAH		
AMERICAN OIL, SALT LAKE CITY		101
CHEVRON OIL, WESTERN DIV., SALT LAKE CITY	27,000	118

capacity necessary to supply the local construction market. Contacts with the industry have led to several suggestions for the possible application of solar energy manufacturing of cement which are summarized in Figure III-43. The normal flow of material and heat in a dry process plant is shown in solid lines. Potential applications for solar heat are shown in dashed lines. The first application would be in pre-drying. This would be applicable to those plants located at wet quarries. The second application for some wet quarries is to provide solar input to the crusher-dryer in the form of hot air. A third application suggested is preheating or precalcining the solids before entering the kiln.

Figure III-43. Cement Manufacture Dry Process

The precalcining application appears to be the most effective method of introducing high quality solar heat into the reaction system directly with a minimum of equipment. Solar energy introduced at the precalcining step would displace coal or other fossil-fuel otherwise consumed at the kiln. Also precalcining would reduce the size of the kiln required at a new plant or alternatively at an existing plant it could increase production from an existing kiln. Calculations indicate that a 600,000 ton/year current plant would require a precalcining energy input rate of 180 MBtu/hr. This would provide a substantial market for solar IPH, provided DOE solar equipment cost goals are achieved.

The technology assessment of Reference III-36 summarized the above application studies and recommended a program approach to the development of solar IPH systems. The suggested approach included expansion of economic and application studies, design and integration analysis of specific industrial applications, and further development of solar high-temperature technology.

b. Field Survey

Subsequent to the technology assessment, a field survey was conducted to assess potential applications of solar thermal electric technology to supply mid-and high-temperature process heat to the primary metals, paper and pulp, and stone, clay and glass industrial groups. Interviews with industrial associations and representative industrial plants were held to obtain feedback on solar impact and feasibility. Since only a limited number of interviews could be conducted, a selection was made based on the high-temperature characteristics, energy use, and geographic location of the larger firms. Typical temperature requirements for these industries are shown in Figure III-44. Except for paperboard mills, the bulk of the energy use was above 1800°F, and most of the industries used waste heat from the

high temperature process to supply lower temperature needs. In the case of paperboard mills about 10% of their energy is used for calcining, and the remainder supplies steam in a cogeneration mode to satisfy electrical and low-temperature process heat requirements. The annual energy use at the level 3 SIC code for these industries is shown in Table III-11. It is seen that there is a large potential for fossil fuel savings, provided that a significant number of plants are in regions of high insolation, and that their processes are compatible with a solar system.

- DESIRED WORKING FLUID IS HOT GAS
- ALL INDUSTRIES REQUIRE 1800°F OR HIGHER

Figure III-44. Process Heat Temperature Requirements for Selected Industries

Table III-11

Energy Use by Selected Industries
1976 Survey of Manufacturers

SIC	Industry	Annual Energy Use (Trillions of Btu)
262,263	Paper Mills and Paperboard Mills	1053
322	Glass; Pressed or Blown	215
325	Structural Clay Products	104
327	Concrete, Gypsum, Lime	223
331	Blast Furnace and Basic Steel	1524
333	Primary Non-Ferrous Metals	442
334	Secondary Non-Ferrous Metals	35

Much of this information was developed through discussions with the various industry associations. Interviews were held with 19 associations, and the results are reported in detail in Appendix B of Reference III-37. The final selection of companies to be interviewed is shown in Table III-12. In many of the cases, the particular industry selected accounts for the largest share of energy use within an industrial group. For example, glass containers account for 52% of the energy use in the glass industry, and is over twice that of the flat glass industry. In the concrete, gypsum and lime industry (SIC 327), lime represents 44% of the total energy use. Similarly, the brick and structural clay tile industries use 55% of the energy represented by structural clay products (SIC 325). The companies listed in Table III-12 have large plants in the southern and western regions of high insolation.

Table III-12. Field Survey Participants (IPH)

INDUSTRY	SIC	COMPANY	INTERVIEW LOCATION STATE (City)	MANAGEMENT LEVEL BRIEFED
PAPERBOARD MILLS	2631	FIBREBOARD/LOUIS-PAC	CA (Antioch)	Mgr, Eng
		SOUTHWEST FOREST IND	AZ (Phoenix)	Sr. V.P., ADMIN
GLASS CONTAINERS	3221	GLASS CONTAINERS CORP/ NORTON SIMON	CA (Fullerton)	V.P.
		KERR GLASS MFR CORP	CA (Los Angeles)	ASST V.P., MFR
		THATCHER/DART IND	CA (Los Angeles)	CORP GR V.P., TECH PLANNING
BRICK	3251	ACME/JUSTIN IND	TX (Ft Worth)	GEN PROD MGR
		HENDERSON CLAY PROD	TX (Henderson)	V.P. / GEN MGR
CLAY	3259	GLADDING, McBEAN & CO	CA (Corona)	PROD MGR
		PACIFIC CLAY PROD	CA (Santa Fe Sprs)	MGR, CHEM MFR & RESEARCH
LIME	3274	U.S. LIME/FLINTKOTE	CA (Monterey Park)	V.P., PRODUCTION
STEEL	3312	KAISER STEEL	CA (Fontana)	DIV SUPT, ENG & UTIL
		U.S. STEEL	PA (Monroeville)	DIV CHIEF, PROC ANAL
SECONDARY ALUMINUM	3341	TRI-ALLOY	CA (Montclair)	PLANT ENG
		U.S. REDUCTION/AM-CAN	CA (Fontana)	PLANT ENG

Each industrial interview began with a briefing on the status of solar technology. Current DOE projects were described, and operation of the central receiver and distributed collector systems were also discussed. The briefing content also included charts showing three types of solar systems for three different temperature ranges, a map with insolation contours for the United States, and data on land requirements to achieve a given displacement of fuel or a given level of steam generation for industrial process heat solar energy systems. A chart on the operational, technical, and financial issues associated with possible solar adoption was then used as a starting point for detailed discussions. Results of the interviews are documented in Appendix A of Reference III-37.

An initial analysis of the solar process heat applications identified in the industrial interviews was made to identify the more attractive candidates. Three temperature ranges, 350°F-550°F, 550°F-1000°F, and 1500°F-2000°F were considered so that the three types of hardware currently under development for solar electric applications could be reviewed for potential utilization in producing industrial process heat. Although there were some requirements for thermal energy in the lowest temperature range, these could generally be satisfied using waste heat available as a product of concurrent higher temperature processes. Thus, a solar system supplying only lower temperature heat would not be attractive for these industries. For the higher temperature ranges, preliminary solar system schematics were outlined for each industry using representative thermal energy, electrical energy, and temperature requirements. A sample schematic for the brick industry is shown in Figure III-45. Estimates were also made of both the annual potential fuel savings and the land area requirements for each application.

Figure III-45. Solar High Temperature IPH System for a Brick Plant

Although the primary metals industry is very energy intensive, the interviews confirmed that there is very little potential for solar. The iron and steel industry currently uses coal as a reducing agent, and there is sufficient excess heat to satisfy other lower temperature needs. The aluminum, copper and zinc industries generally use electrolytic processes, and thus are not presently candidates for solar industrial process heat. Only a few possible applications exist in this industrial group in secondary aluminum production and in limited reheating in the steel and copper industries. If increasing costs of electricity and energy shortages force a conversion from current metal reduction processes to high-temperature chemical reduction processes, the applicability of solar IPH could increase.

A potential market does appear to exist for solar IPH in the glass container, brick and clay, and lime and cement industries. In addition, a solar total energy system involving generation of electricity using steam turbines and making use of the waste heat for process needs could have potential in the paper mill and paperboard mill industry. Although this industry already burns its own wastes and generates some of its own electricity, solar is a clean energy source which additionally could reduce the use of fossil fuels.

Current energy use and potential solar applications for a selected subset of these industries are shown in Table III-13. By the year 2000, this energy use is forecast to increase by 50%, with most of the growth projected for the south and southwest, regions of higher insolation. Once the technology is tailored for the industry and the cost of solar system reduced, there is a potential for fuel savings in these industries of over 1/2 quad annually.

Table III-13. Potential Solar Applications for High-Temperature Industrial Process Heat

INDUSTRIAL GROUP	SPECIFIC INDUSTRY	1976 INDUSTRY ENERGY USE, (10 ¹² Btu/yr)	SOLAR APPLICATION		% SOLAR SELECTED EXAMPLE
			POSSIBLE SOLAR CONCEPT	PROCESS	
STONE, CLAY AND GLASS	GLASS CONTAINERS	215	OPEN-CYCLE HOT AIR WITH FOSSIL FUEL BOOST	FURNACE AND KILN FIRING, PRE-HEAT	40
	BRICK CLAY PIPE CERAMIC TILE EXPANDED SHALE	104			47
	LIME, GYPSUM, PLASTER	223	RADIANT HEAT RECEIVER, OR OPEN-CYCLE HOT AIR	LIME CALCINING	37
PRIMARY AND SECONDARY METALS	NON-FERROUS METALS	477	OPEN-CYCLE HOT AIR	FURNACE FIRING FOR SECONDARY ALUMINUM	52
PAPER AND ALLIED PRODUCTS	PAPER MILLS AND PAPERBOARD MILLS	1053	STEAM AND OPEN-CYCLE HOT AIR	STEAM FOR COGENERATION, AND HOT AIR FOR CALCINING	32

Some of the technical considerations of interest to the industrial firms included the need for precise temperature control in the glass, brick and clay industry, and the ability to switch from solar to fossil fuel operation without adversely affecting their processes. Also, techniques would have to be developed for the efficient transport of hot air from the solar receiver to the furnace or kiln where it would be utilized. Finally, the pressures and control of the oxidation or reduction atmosphere in their furnaces or kilns would require additional review. In general, these industries were not concerned about the operation of the solar portion of the system, and felt that a few years of full-scale operation would be sufficient to judge the adequacy of that subsystem.

Other issues surveyed included land availability and plant investment criteria. Half of the plants surveyed had sufficient land for solar collectors. Land was less available in the glass and secondary aluminum industries where the plants are located close to their markets or sources of raw materials, and more available in the clay and brick industries which are

located in the more remote areas. If a new plant were to be built, land might be more available since the tendency is to locate in an area where land is relatively inexpensive. Present plant investment criteria differ between firms in a given industry and between industries, with payback periods varying from 2-3 years in the brick and clay industries, to 5-7 years in the glass industry.

In order to encourage the development of solar IPH systems, a number of actions were formulated for possible DOE implementation. For each of the industries which appeared favorable, it was recommended that (1) conceptual design and technology application studies be initiated involving the designers/suppliers of the furnaces and kilns which are common to the industry, (2) the current market survey and analysis program be expanded to assess market potential, determine field test programmatic requirements, and evaluate application economics, and (3) additional discussions and interchanges be initiated with the industrial associations to expedite the technical information transfer between the user and the solar system designer/supplier. All of the above should be phased to structure engineering field tests in the more promising industries.

3. SOLAR FUELS AND CHEMICALS

A solar fuels and chemicals study was performed subsequent to the process heat study to identify new industrial processes for the production of transportable fuels and essential chemicals which could capitalize on the high temperatures achievable through solar thermal power technology. The primary accomplishment of this study was the identification of new closed-loop thermochemical processes for the reduction of carbon dioxide to carbon monoxide, one of the two basic building blocks for the synthesis of transportable fuels and organic chemicals by the well-known Fischer-Tropsch

process. Figure III-46 illustrates the wide variety of fuels and materials which can be produced from CO and H₂ through the use of the carbon recovery cycle. A near-term application of these processes would use carbon from fossil fuels in an open-loop system, rather than carbon from the closed-loop recovery system, to reduce the CO₂ to CO. The study was documented in Reference III-38.

Figure III-46. Carbon Cycle Concept

The solar fuels and chemicals study was limited to the examination of processes requiring temperatures in excess of 1000°K (1373°F) since lower temperature processes had already been examined in studies concerned with the application of waste heat from nuclear power plants to industrial processes. In developing the carbon cycle processes, the primary activity

included an extensive literature search and the thermodynamic evaluation of a number of candidate chemical cycles. In reviewing the existing chemical literature, slightly over four million abstracts were accessed, using a key word search by means of a computer. Approximately 330 publications were identified as having potential value. Each of these abstracts was reviewed and 104 of the technical articles were subsequently examined in detail. In addition, many of the authors were contacted for information on more recent publications.

Although both hydrogen and carbon closed- and open-loop chemical cycles were studied, it was concluded that the carbon cycles offered sufficient additional potential to warrant concentrating on them in subsequent work. Among the reasons for this selection is the fact that, whereas over 98 percent of the energy used to reduce the CO_2 to CO is released in the combustion of CO to CO_2 , only about 75 percent of the energy required to reduce the H_2O to hydrogen is released when the hydrogen is burned, due to the fact that water is formed as a vapor rather than in the liquid state. Thus, the overall efficiency is higher for the carbon cycle than for the hydrogen cycle.

Carbon monoxide, in addition to being used as a feedstock for the production of hydrogen and organic chemicals, is an excellent fuel and can be used to power existing fossil fuel power plants for the production of electric power and industrial process heat. Hydrogen can be produced from CO by means of the water-gas shift reaction:

Subsequently, hydrogen and carbon monoxide can be combined in the Fischer-Tropsch process over a number of specific catalysts to form methane, methanol, gasoline, higher alcohols, ethylene glycol, and numerous other organic chemicals which have a large commercial market.

Several commercial chemical processes exist currently with the capability of separating carbon dioxide, which comprises 12 to 18 percent of power plant stack gas, from the balance of the flue gas. In the near term the CO_2 can be reduced to CO by coal or other carbonaceous materials. However, for the long term, it is desirable to develop a closed-loop carbon recovery cycle to reduce the CO_2 to CO and oxygen, using carbon produced in the cycle itself to accomplish this reduction. Three thermodynamically-allowed processes for the reduction of CO_2 (see Table III-14) were identified with theoretical thermodynamic efficiencies between 44 and 60 percent.

Table III-14. Potential Carbon Cycles

CYCLE	THEORETICAL EFFICIENCY (%)	
	WITHOUT SEPARATION	WITH SEPARATION ^a
<u>OPEN-LOOP CYCLE USING EXTERNAL CARBON SOURCE</u>		
$\text{C} + \text{CO}_2 = 2\text{CO} \text{ (1000}^\circ\text{K)}$	98	
<u>CLOSED-LOOP CYCLES TO PRODUCE CARBON</u>		
<u>DIRECT REDUCTION OF CO_2</u>		
$2\text{Cd (l)} + \text{CO}_2 = 2\text{CdO} + \text{C} \text{ (600}^\circ\text{K)}$	56	46
$2\text{CdO} = 2\text{Cd (g)} + \text{O}_2 \text{ (1900}^\circ\text{K)}$		
$2\text{Zn (g)} + \text{CO}_2 = 2\text{ZnO (s)} + \text{C} \text{ (1300}^\circ\text{K)}$	44	37
$2\text{ZnO} = 2\text{Zn (g)} + \text{O}_2 \text{ (2400}^\circ\text{K)}$		
<u>SECONDARY REDUCTION OF CO_2 VIA CO</u>		
$\text{C} + \text{CO}_2 = 2\text{CO} \text{ (1000}^\circ\text{K)}$	60	49
$2\text{Ni} + 2\text{CO} = 2\text{NiO} + 2\text{C} \text{ (600}^\circ\text{K)}$		
$2\text{NiO (l)} = 2\text{Ni (l)} + \text{O}_2 \text{ (2850}^\circ\text{K)}$		

^a Accounts for work required to separate products by suggested chemical process.

Both experimental and theoretical work are necessary to establish the full potential of the closed-loop carbon recovery cycles. The purpose of the experimental work is to demonstrate that at least one of the cycles, which has already been identified as thermodynamically feasible, will actually proceed at a reasonable rate at or near the predicted temperature. The theoretical effort is attempting to identify additional thermodynamically allowable carbon and hydrogen cycles with higher efficiencies than those already identified. As soon as one of the processes has been shown to be feasible, including the demonstration of a commercially viable reaction rate, a conceptual design should be established for a plant to produce carbon monoxide from CO_2 by a closed-loop carbon recovery cycle. The design should include options for both an electric power plant burning CO and O_2 and a chemical plant to convert CO and H_2O to CO_2 and H_2 . The H_2 and additional CO can then be reacted over catalysts in the Fischer-Tropsch process to form the desired chemical(s), including gasoline. These plant designs are necessary to establish plant and process costs for the production of power and chemicals by means of solar energy.

In addition to the fuels and chemicals work described previously, Reference III-38 describes work also carried out in the following areas:

- Review and presentation of data identifying the fuels and materials which are the most significant in the energy, economy, and identification of promising relationships to solar technology.
- Examination of traditional methods of production for fuels and materials to determine potential energy savings.
- Summary of the literature on the hydrogen economy and the production and use of hydrogen for energy storage, transportation, conversion, and metals production.

- Presentation of new concepts for materials production and closed-loop energy storage capitalizing on the higher efficiencies and new processes possible through high temperature solar technology.

In the area of energy economy, a cursory review of the role of fuels and materials determined that fuels and materials are significant in this economy and indicated that the fuels and materials sector is compatible with temperatures achievable with the state-of-the-art in solar technology. For example, liquid fuels account for 44 percent of all energy projected to be consumed in the United States between 1970 and 1985; currently, these fuels account for about 95 percent of all transportation energy. Transportation energy (25 percent) together with industrial energy, including electrical power generation, account for approximately 70 percent of the National total energy consumption. Production of fuels and materials accounts for about half of the industrial energy consumption with approximately half of this energy going into the production of iron and petroleum. Solar thermal power technology currently under development should allow temperatures of the order of 1400°K (2060°F) to be achieved in the solar receiver and to be used for the production of fuels and chemicals in the near term through open-loop cycles and in the far term through closed-loop carbon recovery cycles.

In discussing the production of fuels and materials, the primary emphasis has been placed on the existing techniques used to produce the fuels and metals and on indicating how solar thermal technology might be used to reduce the consumption of depletable energy that is currently being used in their production. For example, petroleum production uses approximately 10 percent of the energy in the oil to provide process heat in the refining step. This energy could conceivably be replaced by solar energy to save significant amounts of oil. In the metals reduction sector, solar energy could provide the high temperatures needed to reduce the ore to the metal, but it is not obvious that it would be feasible to produce aluminum or magnesium in commercial quantities through the use of solar energy.

The use of solar energy in connection with closed-loop energy storage systems has a high potential, but little consideration has been given to this application of solar energy in the past. A novel concept has been conceived by Aerospace consisting of a dual system for energy storage which features a gaseous medium ($\text{CO} + \text{H}_2$) for transmission and condensed system (NaHF_2) for storage. While this system incurs the penalties of additional complexity and some loss of efficiency, it requires significantly less storage volume than a gaseous system and should be capable of being constructed for a much lower capital investment.

Potential problem areas pertinent to solar-derived fuels and chemicals have been identified. These problems are primarily associated with the limited high temperature experience in industry and include materials compatibility, separation of reaction products, development of solid electrolytes and high-temperature electrodes, selective emission of receiver coatings at high temperature, and a lack of chemical kinetics data and high-temperature thermodynamic data. The kinetics and thermodynamic data are essential for the determination of the technical and economic feasibility of any new process. Research should be pursued to acquire the necessary data to demonstrate the feasibility of these new solar fuels and chemicals processes.

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- III-22 Solar Total Energy Systems Technical Progress Report, Aerospace Corporation Report No. ATR-77(7692-01)-1, dated 1 August 1977.
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- III-34 Solar-Powered Irrigation Systems Study Technical Summary Report, Volume I: Analysis of Market Potential, Aerospace Corporation Report No. ATR-78(7693-01)-2, dated 31 May 1978.
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APPENDIX A

DATA BASES AND COMPUTER PROGRAMS

The purpose of this appendix is to summarize the various data bases and computer programs utilized in Aerospace's Solar Thermal Mission Analyses. Descriptions of each element are provided, along with references to available, more detailed documentation. The relationships among these elements are shown in Figure A-1. In a typical large power systems analysis, hourly electric demand data from a specific real or synthetic utility is processed by a demand forecasting program and combined with insolation data in a performance simulation to yield predicted fuel displacement and solar plant capacity factor. During the latter simulation, solar plant characteristics, e.g., collector area and storage capacity, are usually varied to optimize the performance. Utility generating unit characteristics are then added and used in various dispatch or system reliability analysis models to determine loss of load probability (LOLP) and infer the capacity displacement of the solar plant. Finally, capital and operating costs of conventional and solar plants are combined in a power plant economic model to determine the relative busbar costs of energy production, and the effect on utility financial parameters. In the analysis of solar total energy systems and small power electric systems, a further step is employed in which an applications (potential market) data base is combined with cost information to determine market penetration estimates. The pages which follow describe each data base and computer program in a common format, and indicate their use in the various mission analysis studies.

Figure A-1. Solar Thermal Mission Analysis Elements

Category: Demand Data Bases

Description: These data bases were developed by processing raw utility data defining the integrated hourly demand for entire utility systems into a common Electric Edison Institute (EEI) format, and storing the data on magnetic tape for later input to demand forecasting programs. The data from the utilities generally were complete histories for a number of years or FPC Form 12 data only which provides hourly demand data for the first weeks in April, August and December. Data were also separately supplied by the utilities and the regional power associations on their long-range peak demand forecasts. The data base derived from the EPRI synthetic utility model included demand levels of monthly peaks.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
So. Cal. Edison Demand, 1962-1972	Southern California Large Power Systems Study	Proprietary, not available for external distribution
Southwest Utilities Demand (see listing, Table A-1)	Southwest Large Power Systems Study	Continuous data proprietary, Form 12 data available from FPC records
Nationwide Utilities Demand (see Table III-4 in text)	National Large Power Systems Study	Form 12 data, FPC records
EPRI-F Synthetic Utility Demand	Repowering Analysis	See Ref. A-1

Table A-1. Demand Data Base Content - Southwestern Study

<u>Data Base / Utility-Agency</u>	<u>Deck Name*</u>	<u>Card Abbreviation**</u>	<u>Time Spans***</u>	
DATA BASE DMD/A (Local time)				
Arizona Public Service Co.	APS	AR	1962-1972	(Form 12)
City Public Service Board	CPSB	CP	1967-1973	(Continuous)
Dallas Power & Light Co.	DPL	DA	1964-1972	(Form 12)
Edwards Air Force Base	EAFB	ED	1971	(Continuous) 2 Subst.
			Feb. 1973	(Continuous) 1 Subst.
El Paso Electric Co.	EPE	EP	1962-1966	(Continuous)
			1967-1968	(Form 12)
			1969-1971	(Continuous)
			1972	(Form 12)
Los Angeles Department of Water & Power	LADWP	LA	1962-1973	(Continuous)
DATA BASE DMD/B (Local time)				
Nevada Power Co.	NPC	NP	1962-1965	(Form 12)
			1968-1972	(Form 12)
Oklahoma Gas & Electric Co.	OGE	OK	1962-1972	(Form 12)
Pacific Gas & Electric Co.	PGE	PG	1962-1972	(Form 12)
Public Service Co. of Colorado	PSCO	CO	1962-1972	(Form 12)
Public Service Co. of New Mexico	PSNM	NM	1962-1968	(Form 12)
			1969-1973	(Continuous)
Southern California Edison Co.	SCE	SC	1962-1973	(Continuous)
Sacramento Municipal Utility District	SMUD	SM	1962-1972	(Form 12)
Sierra Pacific Power Co.	SPPC	SP	1962-1972	(Form 12)
Texas Electric Service Co.	TES	TE	1965-1972	(Form 12)
Tucson Gas & Electric Co.	TGE	TU	1962-1972	(Form 12)
Texas Power & Light Co.	TPL	TP	1962-1972	(Form 12)
Utah Power & Light Co.	UPL	UP	1962-1972	(Form 12)
DATA BASE DMD/D (Standard time)				
Los Angeles Department of Water & Power	LADWP	LA	1962-1973	(Continuous)
Sacramento Municipal Utility District	SMUD	SM	Jul. 1964- Feb. 1974	(Continuous)

* UPDATE deck identifiers cannot contain special characters such as ampersands (&). Therefore, the above abbreviations were selected.

** Utility abbreviations are constrained to two characters on the Aerospace Corporation adaptation of the EEI card format.

*** The notation Form 12 is used to indicate hourly observations during the first full weeks of April, August, and December. Continuous implies a sequence of hourly observations without chronological breaks.

Category: Insolation Data Bases

Description: Computer simulations of solar energy systems employing focusing collectors require input on hourly direct normal insolation typically for each hour of the year. Since few measurements of this parameter were available during early solar thermal studies, an estimation technique was developed from a linear correlation between direct and total insolation. Data bases were established and stored on magnetic tape, whose content included the following:

- Identifying information, such as location, date, time and solar position
- Hourly insolation data, including extraterrestrial, normal incidence and total insolation, as well as the ratio of total to extraterrestrial insolation
- Weather data including temperature, humidity, sky cover and information on cloud cover, precipitation and winds

A total of ten stations were included in the data base for the initial large power systems studies. This was expanded to 20 stations for the Southwest study, and 34 for subsequent studies. By 1977, additional measurements of direct insolation became available, and improvements were made to the total insolation data originally supplied by the National Oceanic and Atmospheric Administration (NOAA). This led to the development of a revised insolation data base, in which the linear regression used for estimating direct normal insolation was replaced with a piecewise linear fit to the new data. This data base includes 26 stations, and is available on magnetic tape in a standard (SOLMET) format from both Aerospace Corporation and the National Climatic Center (NCC) in Asheville, North Carolina.

For many application and market penetration studies, direct insolation on an hourly basis is not required, and data on a daily, monthly or annual basis is sufficient. Mean daily values of direct and global (total) insolation for 27 stations were calculated by Aerospace, and similar data have been prepared by A. D. Watt of Watt Engineering, Limited. A typical set of contours from the latter data base is shown in Figure A-2.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Direct Normal Insolation* for Southern California (10 stations)	Southern California Large Power Systems Study	See Table III-1 in text, no longer available
Hourly Insolation Climatology Data Base* (34 stations)	Southwest and early National Large Power Systems Studies, initial STES Studies	Reference A-2, available on 9 magnetic tapes
Revised Insolation Climatology Data Base (26 stations)	Later National Large Power Systems and STES Studies	Reference A-3, available from NCC and Aerospace (separate tape for each station)
Mean Daily Direct-Normal Insolation by month and year (26 stations)	Used in accuracy checks with A. D. Watt data	Reference A-3 (Table 5-3) available from NTIS as document No. SAND-78-7047
Average Annual Contours of Direct Normal Insolation	STES, SPS, and SIS Market Studies	Reference A-4, available from U. S. Government Printing Office as document No. HCP/T2552-01

* Obsolete - replaced by later data bases

Figure A-2. Contours of Average Daily Direct Normal Insolation

Category: Market & Energy Price Data Bases

Description: A variety of data bases were developed to characterize current or forecast energy use as a function of location and type of application. These were either used directly or input to a preprocessor program for use in market studies. Data bases were also developed which forecast prices of thermal or electric energy as a function of fuel type. The major data bases included:

- Industrial Applications - This data listed energy use by fuel type, state and level 3 SIC industry, extracted from the 1974 Survey of Manufacturers (conducted by the Bureau of the Census). This was combined with state and industry forecasts for 1985-2015 (by Sherman Clark Associates) in a STES Application Model preprocessor program for use in market penetration studies.
- Small Power Plant Applications - Two data bases were developed; an inventory of utility small generating units by utility name and location listing the type, number and size of each unit, and a similar inventory of industrial small generating units.
- Irrigation Applications - This data base utilized the 1969 Census of Agriculture and irrigation surveys to provide county-related data for the seventeen western states. It included irrigated acreage by crop and type of irrigation, pumping depth, irrigation efficiency and crop watering requirements. The data was input to a computer program which calculated irrigation energy demand.

- o Energy Price Forecasts - Two data bases were developed by Sherman Clark Associates; agricultural fuel and electric energy prices by county for six western states, and a more comprehensive forecast of residential, commercial, industrial, and power plant fuel and electricity prices by state and fuel type for the 1985-2015 period, in five year increments. A sample of the latter is shown in Table A-2 for the state of Maryland.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Industrial Energy Use Forecasts (1985-2015)	STES Market Penetration	Reference A-5, available from NTIS as document No. SAN-1101-78/1(Vol. 2)
Inventories of Utility and Industrial Small Generating Units (≤ 10 MWe)	Small Power Systems Study	References A-6 and A-7, available from NTIS as documents Nos. ATR-78 (7693-05)-1 (Vol. 2) and DOE/ET/20516-1
Irrigation Data Base (17 Western States)	Solar Irrigation Study	Not documented
Energy Price Forecasts* (1985-2015)	Recent Large Power and all Small Power Systems Studies (STES, SSPS, SIS)	Reference A-5 (see above)

* Should be updated, in view of recent large OPEC price increases

Table A-2.
Energy Prices⁺ in Maryland and Washington, D. C.
(In Original Units and Cents per Million Btu), 1974-2015

	Original Units*									Cents per Million Btu								
	1974	1975	1985	1990	1995	2000	2005	2010	2015	1974	1975	1985	1990	1995	2000	2005	2010	2015
Residential																		
Natural gas	171	233	390	501	586	625	617	608	606	167c	227c	380c	489c	572c	610c	602c	593c	591c
Electricity	3.58	3.95	4.30	4.60	5.00	5.40	5.70	6.20	6.70	1049	1157	1260	1348	1465	1582	1670	1817	1963
Light fuel oil	35.8	36.0	56.6	62.9	70.0	76.9	77.1	77.5	77.7	257	258	406	452	502	552	553	556	558
Commercial																		
Natural gas	149	206	364	479	568	610	606	602	604	145	201	355	467	554	595	591	587	589
Electricity	3.59	3.85	4.40	4.70	5.10	5.50	5.80	6.30	6.80	1052	1128	1289	1377	1494	1612	1699	1846	1992
Light fuel oil	29.9	32.9	53.0	59.3	66.4	73.3	73.6	73.9	74.2	215	236	380	426	477	526	528	531	533
Heavy fuel oil	11.83	12.52	21.65	24.30	27.30	30.30	30.40	30.50	30.60	194	205	355	398	448	497	498	500	502
Coal	33.56	38.77	48.11	54.81	62.44	71.01	79.54	89.67	101.75	146	159	201	230	262	298	335	376	429
Industrial																		
Natural gas	118	137	295	412	503	548	548	547	554	115	134	288	402	491	535	535	534	540
Electricity	2.34	2.67	3.10	3.60	4.10	4.70	5.20	5.80	6.50	686	782	908	1055	1201	1377	1524	1699	1904
Light fuel oil	26.9	29.9	49.4	55.7	62.9	69.8	70.0	70.4	70.6	193	216	355	400	452	501	502	505	507
Heavy fuel oil	11.53	12.22	21.35	24.00	27.00	30.00	30.10	30.20	30.30	183	194	339	381	428	476	478	479	481
Coal	31.96	36.77	42.77	48.72	55.50	63.12	70.70	79.70	90.44	137	151	179	204	232	265	298	336	382
Power plants																		
Natural gas	60	102	--	--	--	--	--	--	--	59	100	--	--	--	--	--	--	--
Light fuel oil	26.9	29.9	49.2	55.5	62.6	69.5	69.8	70.1	70.4	193	216	353	398	449	499	501	503	505
Heavy fuel oil	10.83	11.52	20.70	23.35	26.35	29.35	29.45	29.55	29.65	172	187	329	371	418	466	468	469	471
Coal	26.96	31.77	35.64	40.60	46.25	52.60	58.92	66.42	75.37	116	130	149	170	194	221	248	280	318
Nuclear	--	0.22	0.39	0.45	0.54	0.66	0.82	1.01	1.26	--	22	39	45	54	66	82	101	126

* Natural gas--cents per thousand cubic feet; electricity--cents per Kwh; light fuel oil--cents per gallon; heavy fuel oil--dollars per barrel; coal--dollars per ton; and nuclear--cents per Kwh.

Sources: Historical--
Projected--SEEA.

+ All prices are stated in 1977 constant dollars except for 1974 and 1975 which are stated in actual dollars.

Category: Demand Forecasting Programs

Description: These programs process utility hourly demand data in a standard EEI format and produce a forecast demand data tape which can be utilized in solar electric plant simulations. They operate by decomposing the input data into daily, weekly and monthly cyclic components, and exponential trends. Printed output includes annual load duration and load energy distributions, load factor, and total energy measures for each forecast year. Although not available in the earlier models, procedures were incorporated which allow for changes in the yearly demand distribution (e.g., from winter to summer peaking).

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Initial Demand * Forecasting Model	Southern California and Southwest Large Power Systems Studies	See Reference A-8 for logic flow diagrams and program listing
Revised Demand Forecasting Model	National Large Power Systems Studies	See Reference A-9 for equation modifications

* Obsolete

Category: Solar Thermal Performance Simulation Models

Description: These models dynamically simulate the interaction of time-varying insolation, electric and thermal demand, and time-lag effects of thermal storage. Variations in turbine efficiency and operating logic are simulated, and geometrical and tracking corrections for alternative collector configurations are included. Equations also account for energy losses in the energy transport and thermal storage subsystems.

Solar power plant simulation outputs include monthly and yearly values of solar thermal power to storage and to the turbine/generator, solar electric power generated and outage frequency distribution, and solar plant capacity factor (solar power output as a percentage of rated capacity of the turbine/generator). In the STES simulation, the outputs also include annual amounts and ratio of displaced thermal and electric energy, and equivalent cost ratio.

These simulations are used to evaluate the relative performance of alternative solar configurations, and optimize subsystem parameters such as collector area and thermal storage capacity as a function of insolation and demand inputs. The solar outage rate from the power plant simulation is input to margin analysis and dispatching programs for economic evaluation (as shown in Figure A-1), and the STES simulation output is utilized in market penetration analyses. By setting the thermal storage to zero and introducing a fossil fuel boiler, the simulation has been utilized in solar/fossil hybrid studies as well.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Solar Thermal Power Plant Simulation Model	Various versions used in Southern California, and National Large Power System Studies, and Solar/Fossil Hybrid Studies	User's Guide available as Reference A-10, which includes program listing and a sample problem
Solar Total Energy System (STES) Simulation Program	Used in STES Studies. Modified versions were created for the SSPS and SIS performance analysis	User's Guide available as Reference A-11, and thru NTIS as document No. ORNL/Sub-7525/2. Input and Program tapes are available thru ORNL. No documentation exists for the modified programs used in the SSPS and SIS analyses.

Category: Utility Interface Programs

Description: These programs determine the net costs or savings resulting from the introduction of solar plants in a utility system. The Marginal Analysis Program (MAP) first estimates the capacity distribution of a grid of conventional power plants required to meet a given loss-of-load probability, using hourly load data as input. Solar plants are then introduced which replace the conventional plants, keeping the total configuration size or generating capacity the same. Solar power outages due to either insolation variations or assumed equipment failures degrade the system capacity, and the program then computes the additional conventional capacity which must be added to maintain the desired loss-of-load probability. The cost of this capacity is then utilized in various power plant economic models as an input in determining solar busbar energy costs.

In the Utility System Economic Model (USEM), input load data is used to compute load duration curves for a utility system, both with and without a new (solar) plant. The program uses these load duration curves to optimize the generating mix and calculate the cost of production. Auxiliary program subroutines calculate fuel savings, manipulate economic parameters, and summarize comparisons.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Margin Analysis Program (MAP)	Southern California, Southwest and National Large Power Systems Studies	User's Guide available Reference A-12.
Utility System Economics Model (USEM)	Solar Thermal Repowering Studies	No formal documentation available

Category: Utility Financial Models

Description: These models provide data on fossil and solar power plant capital investment costs and busbar energy costs for comparative economic studies. Inputs to these calculations include plant construction costs, plant capacity factors and displaced fossil fuels from simulation studies, and back-up capacity requirements from margin analysis studies. Assumptions must also be made on fuel costs and escalation rates, interest rates, cost of taxes and insurance, etc. Major models which were developed included:

- Power Plant Economic Model (PPEM) - This model calculates the construction costs for each plant subsystem account in terms of real dollars and escalates the cost to the start of construction. A cost scaling routine is included to adjust for different plant sizes. The program also accounts for interest and escalation costs during construction. A discounted cash flow technique is used to equate the present value of capital investment with net revenues during operation. Annual fixed and variable costs are combined to calculate busbar energy costs and cash flows.

- Public Utility Financial Analysis and Planning Model (PUFAP) - This model calculates a sequence of financial exhibits applicable to a single power plant within a utility system using accounting principles and formats approximating those in use by the utility industry. Some of the outputs available on an annual basis include cost of service components (O&M, depreciation, taxes, return on rate base), income and retained earnings, balance sheet parameters, cash flow, and rate of return. The model was originally coded in a computer language leased from Getty Oil and is no longer in use at Aerospace. A similar model in FORTRAN is under development.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Power Plant Economic Model (PPEM)	Southern California, Southwest and early National Large Power Systems Studies	User's Guide available as Reference A-13
Public Utility Financial Analysis and Planning Model (PUFAP)	Later National Large Power Systems Studies	This model used a proprietary computer language no longer available to Aerospace. A similar model is now being developed in FORTRAN

Category: Market Potential and Penetration Model

Description: These models combine the performance relationships developed through solar system simulations with specific application data bases to evaluate market potential and/or penetration. They vary in complexity depending on the application, ranging from a simple demand aggregation model for solar irrigation systems to a set of interrelated models for computing STES market penetration forecasts. Highlights of these models are as follows:

- Irrigation Market Energy Demand Program - This model starts with the county data file on crop acreage, irrigation requirements and water pumping depth and computes monthly energy demand for both ground water and surface water pumping. This data is then aggregated to yield statewide and regional energy demand in terms of both electrical and mechanical energy, and equivalent fossil fuels. Penetration of this potential solar market is calculated off-line using the results of SIS economic trade-off studies.
- STES Application Model (SAM) - This program combines the industrial data base discussed previously with statewide insolation data to estimate performance for each industry and location. Levelized costs of STES and fuel price forecasts are then combined with energy growth forecasts to develop the potential STES market. SAM computes equivalent cost ratios (ECR's) and fuel displacement by fuel type for all combinations of 140 three-digit SIC industries, 50 states and 7 future time periods between 1985 and 2015 in five-year increments. The program also aggregates STES energy displacement potential by state, industry, and fuel type. Summary data for applications where $ECR \leq 1$ are also developed for use in ranking studies.

Market Penetration Model (MPM) - This model operates on the output of SAM by treating the ECR for each application and location as a distribution about the median value calculated by SAM. The distributions are obtained using a Monte Carlo technique to combine separate distributions which define the variations within each state of STES size-related costs, insolation, competing fuel costs, and interest rates. The distribution of ECR for each state and industry is appropriately modified by technical and financial risk factors. MPM then computes the percentage of firms having favorable ECR's ($ECR \leq 1$). The resulting market penetration percentages are combined with the potential market computed previously and suitability factors to yield total STES market penetration as a function of state, industry and time.

Small Solar Utility and Industrial Market Models (SSUMM and SSIMM) - These models perform functions similar to those of SAM and MPM discussed above, except that they operate on data bases of specific existing utilities and industrial applications. For each application, ECR's are computed as a function of time, where the calculations includes effects of replacement and repowering options and ownership economic factors. These results are then used to compute probabilities of solar adoption, ranked, and aggregated to yield national penetration forecasts of the small power utility and industrial markets.

DATA BASE OR MODEL	APPLICATION	DOCUMENTATION/AVAILABILITY
Irrigation Market Energy Demand Program	Solar Irrigation Study	See Reference A-14 for logic flow and equations.
STES Applications Model (SAM)	Solar Total Energy Systems Study	User's Guide available as Reference A-15, and thru NTIS as document No. ORNL/Sub-7525/3. Input and program tapes available thru ORNL
STES Market Penetration Model (MPM)	Solar Total Energy Systems Study	User's Guide available as Reference A-16, and thru NTIS as document No. ORNL/Sub-7525/4. Input and program tapes available thru ORNL
Small Solar Utility Model (SSUM) and Small Solar Industrial Market Model (SSIMM)	Small Solar Power Systems Study	See Reference A-17 for equations and model descriptions. Available from NTIS as document No. DOE/ET/20516-2

APPENDIX A

REFERENCES

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APPENDIX B

ECONOMIC METHODOLOGY AND COST ASSUMPTIONS

The purpose of this appendix is to present an overview of the techniques and cost assumptions used in evaluating the economics of the various solar thermal power plant configurations considered in Aerospace's Mission Analysis Studies. Specific page references are also provided to allow quick access to detailed equations used in each study. A description of utility financial computer models and their availability has already been presented in Appendix A.

1. ECONOMICS METHODOLOGY - LPSS

In the large power systems studies, solar plants with various assumptions regarding configuration and geographic location were compared with each other and with various kinds and sizes of fossil-fueled electric plants to determine the conditions under which the solar plants would be economically competitive. These economic studies generally compared relative busbar energy costs (mills per kilowatt hour) based on capital investment costs and various sets of assumed economic parameters. Inputs to these calculations included plant construction costs, assumed plant lifetime, and construction period; annual plant capacity factor; and assumed economic parameters such as interest rates, plant and fuel cost escalation rates and costs of taxes and insurance. The effect of the solar plant on utility operations was included by increasing the busbar energy costs to account for additional capacity requirements (determined from reliability analyses), and adding a fuel credit when a solar plant operating in excess of scheduled intermediate demand displaced baseload fuel.

A discounted cash flow technique to equate capital investment costs with net revenues during operation was used in developing the busbar energy costs. The economic analysis first determined the cash outlays required to finance the construction of a power plant by estimating the cost in current dollars, and then determining the additional costs incurred by escalation from current dollars through the construction period. The interest expenses incurred from the start of construction through the completion of the power plant was also calculated. This combination of construction and escalation costs, and interest expense during the building of the power plant determined the present value of the total capital investments at the year of commercial operation. The power plant busbar energy cost (mills per kWh) was then calculated to yield the same present value for the net revenue after considering any further capital investment and all operating expenses incurred during the plant operational period. These expenses were classified as either fixed (e.g., interest, dividends, debt, depreciation, and taxes) or variable (e.g., operations, maintenance, and fuel) expenses. The discount rate used in these calculations was a weighted average of return on common and preferred equity, and long term debt (after taxes). Equations completely describing these calculations are listed in Appendix A of Reference B-1, and their application to the various large power systems studies is discussed in Section IV.D of Reference B-2.

2. ECONOMICS METHODOLOGY - STES, SSPS, SIS

In the total energy, small power and irrigation systems studies, a common methodology was employed using the concept of equivalent cost ratio (ECR). This was defined as the ratio of the annualized cost of a solar installation to the annualized cost of the electric and/or thermal energy which the solar system displaced. Thus any system with an $ECR \leq 1$ would be cost effective over its expected lifetime. The ECR was calculated from:

$$ECR = \frac{ACR \cdot CC}{ED \cdot AEC}$$

where ACR = annualized cost rate

CC = capital costs

ED = alternative energy displaced annually

AEC = annualized unit cost of the alternative displaced energy

The ACR is usually computed as the sum of four terms; the annualized cost of capital rate, operation and maintenance cost rate, insurance cost rate and property tax cost rate. The discount rate used in computing the cost of capital should be the same as the rate used in annualizing AEC. A generalized discussion of the annualized cost rate methodology is presented in Reference B-3. Specific equations and assumed or derived economic parameter values used in each study are documented as follows:

- STES - Reference B-4, Appendix B, and Reference B-5, Appendix A
- SSPS - Reference B-6, Section 6.2.3
- SIS - Reference B-7, Section 9

A summary of the various financial and economic factors used in both the above studies and the Large Power System Studies is given in Table B-1. Note that many of the factors are a strong function of the type of ownership. Also, any comparison must discern whether before-tax or after-tax values are being presented and whether or not inflation effects are included.

3. SOLAR COST ASSUMPTIONS

The costs of the various solar systems used in these studies were generally derived from design/cost estimates by the NSF, ERDA and DOE system contractors. For the large power plant studies, solar plant costs were expressed by investment account (in $\$/kW_e$) in accordance with the account structure used by the Federal Power Commission. Three additional accounts were provided for the solar plants: heliostats/collectors; receiver/tower/heat exchanger, and thermal storage/tanks (see Table III-3). The Power Plant Economic Model was used along with estimated escalation rates of each account to compute the capital investment at the year of commercial operation. Cost-scaling relationships were also included to determine the relative economics of different size power plants.

Table B-1. Baseline Economic Parameters

STUDY	LPSS				STES	SPSS			SIS		
	SO. CALIF.	SOUTHWEST		NATIONAL							
OWNERSHIP	PRIVATE UTILITY	PRIVATE UTILITY	PUBLIC UTILITY	PRIVATE UTILITY	INDUSTRIAL	PRIVATE UTILITY	MUNICIPAL UTILITY	INDUSTRIAL	LARGE FARM	SMALL FARM	COOPERATIVE
ASSUMED PARAMETERS:											
PLANT LIFE-yrs (oper./acct.)	30/30	30/30	30/30	30/20	30/20	30/20	30/20	30/20	30/30	30/30	30/30
DEBT RATE (%) ^a	5.4	8.0	5.0	8.5	4.5	3.25	2.30	4.5	5.0	5.0	2.0
EQUITY RATE (%) ^a	11.7	12.0	-	12.6	10.0	7.0	-	10.0	-	-	-
DEBT/ASSET RATIO	0.5	0.5	1.0	0.55	0.5	0.55	1.0	0.5	1.0	1.0	1.0
INCOME TAX RATE (%)	40 ^b	40 ^b	0	50	50	50	0	50	50	0	30
INSURANCE RATE (%)	0.2	2.0	2.0	2.0	0.5	0.25	0.25	0.5	0.5	0.5	0.25
PROPERTY TAX RATE (%)	0.25				2.0	2.0	2.0	2.0	2.0	2.0	2.0
INVESTMENT TAX CREDIT (%)	0	0	0	10	10.0	10.0	0	10.0	10.0	0	0
O&M COSTS (% of cap. inv.)	0.8	0.8	0.8	1.5	2.0	2.0	2.0	2.0	1.0	1.0	2.0
INFLATION RATE (%)	3.0	3.0	3.0	5.5	-	-	-	-	-	-	-
FUEL COST ESCALATION RATE (%) ^a	6.7-8.2	3.4-7.8	3.4-7.8	6.5-7.5	2-4	2-4	2-4	2-4	1.5-2	1.5-2	1.5-2
CALCULATED PARAMETERS:											
COST OF CAPITAL (%) ^a	7.4	8.0	5.6	11.2	6.13	4.0	2.3	6.0	2.5	5.0	1.4
BEFORE-TAX ANNUALIZED COST RATE (%) ^a	NA	18.6	8.5	17.1	12.1	9.5	8.0	12.1	8.0	9.3	7.8

^a Entries for LPSS include inflation.

^b Tax rate includes effect of investment credit.

In the case of the STES study, the market penetration analysis required inputs on solar system cost of a central receiver configuration as a function of both size and time. A special Aerospace cost model (ST-N127) was developed which provided STES costs for capacities from 10kW_e up to 10MW_e , and operational start dates for 1985, 1990 and 1995. These cost forecasts are shown in Figure B-1, where they are compared with test facility, pilot plant, and commercial plant cost estimates developed by DOE contractors.

A summary of solar costs used in each of the Aerospace studies is shown in Table B-2. It should be noted that a range of configurations, sizes and operational start dates are represented. Since the studies were performed over a period from 1972 through 1979, a number of different base years were used for the constant dollar values. The second column of each study therefore lists unit and system costs in 1980 constant dollars. The GNP price deflator was used for the conversion, assuming a 1980 estimated index of 180.0 (1972 = 100). This resulted in the following table of multipliers:

BASE YEAR	1972	1973	1974	1975	1976	1977	1978	1979
Multiplier to convert to 1980 \$	1.800	1.698	1.549	1.414	1.231	1.265	1.180	1.088

Figure B-1. Comparison of Aerospace Model of STES Total Costs (\$/kW_e) with Contractor Data, 1977 Cost Base

Table B-2. Solar System Study Cost Assumptions (in base year and 1980 dollars)

STUDY	LPSS						STES		SPSS		SIS	
	SO. CALIF.		SOUTHWEST		NATIONAL							
CONFIGURATION	PARABOLIC TROUGH		CENTRAL RCVR		CENTRAL RCVR		CENTRAL RCVR		CENTRAL RCVR		PARABOLIC TROUGH	
OPERATIONAL YEAR	1990		1990		1990		1990		1990		1985	
SIZE	1000 MW _e		100 MW _e		100 MW _e		1.0 MW _e		10.0 MW _e		80 kW _e	
SYSTEM LOCATION	YUMA, ARIZ		INYOKERN, CA		INYOKERN, CA		ALBUQUERQUE, NM		INYOKERN, CA		COCHISE CTY, ARIZ	
BASE YEAR FOR DOLLARS	<u>1972</u>	<u>1980</u>	<u>1973</u>	<u>1980</u>	<u>1975</u>	<u>1980</u>	<u>1977</u>	<u>1980</u>	<u>1978</u>	<u>1980</u>	<u>1977</u>	<u>1980</u>
UNIT COSTS:												
COLLECTORS (\$/m ²)	25	45	30	51	61	86	95	120	83	98	151	191
RECEIVER (\$/kW _e)	-	-	95	161	96	136	450	569	439	518	-	-
STORAGE (\$/kW _e -hr)	12	22	15	25	17	24	15	19	16	19	15	19
OTHER* (\$/kW _e)	220	396	291	494	515	728	1245	1575	1774	2093	400	506
SYSTEM COST (\$/kW _e)	891	1604	776	1318	1324	1872	3070	3884	4578	5402	4700	5946

* Includes Indirect and Contingency Costs, Turbine-generator, etc.

APPENDIX B

REFERENCES

- B-1 Power Plant Economic Model Program Description and User's Guide, Aerospace Report No. ATR-74(7417-16)-1, dated 1 June 1974.
- B-2 Solar Thermal Conversion Mission Analysis: Final Report, Aerospace Corporation Report No. ATR-77(7523-22)-3, dated 1 May 1976, issued 25 February 1978.
- B-3 The Cost of Energy from Utility-Owned Solar Electric Systems, ERDA/JPL-1012-76/3 dated June 1976.
- B-4 Solar Total Energy Systems Second Technical Progress Report, Aerospace Corporation Report No. ATR-77(7692-01)-2, dated 1 December 1977.
- B-5 The STES Handbook: A Technique for Evaluating Industrial Applications of Solar Total Energy Systems (STES), Aerospace Corporation Report No. ATR-79(7811-01)-1, dated 1 October 1979.
- B-6 Solar Thermal Small Power Systems Study Program Study Report, Phase II: Study Results, Aerospace Corporation Report No. ATR-79(7780)-2, dated 12 July 1979.
- B-7 Solar-Powered Irrigation Systems Study Technical Summary Report, Volume I: Analysis of Market Potential, Aerospace Corporation Report No. ATR-78(7693-01)-2, dated 31 May 1978.