100 4-1-82 I-2295 ① 382

SANDIA REPORT SAND82-8002 · Unlimited Release
Printed February 1982

CONF-8110176--

MASTER

Department of Energy Solar-Central-Receiver Annual Meeting

Division of Solar Thermal Technology
Department of Energy
Washington, D.C.

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550
for the United States Department of Energy
under Contract DE-AC04-76DP00789

NOTICE

PORTIONS OF THIS REPORT ARE ILLEGIBLE. It has been reproduced from the best available copy to permit the broadest possible availability.

Issued by Sandia Laboratories, operated for the United States Department of Energy by Sandia Corporation.

SAND82-8002
Unlimited Release
Printed February 1982

DEPARTMENT OF ENERGY SOLAR-CENTRAL-RECEIVER ANNUAL MEETING

Sponsored by

Division of Solar Thermal Technology
Department of Energy
Washington, D.C.

ABSTRACT

This document contains the papers presented at the Department of Energy Solar Central Receiver Annual Meeting held in Claremont, California, from October 13 to 15, 1981.

SAND--82-8002

DE82 011932

DEPARTMENT OF ENERGY SOLAR CENTRAL RECEIVER ANNUAL MEETING
CLAREMONT, CALIFORNIA
October 13, 14, and 15, 1981

October 13, 1981: Systems Session
Chaired by A. C. Skinrood, Sandia National Laboratories, Livermore

SYSTEMS SESSION

OVERVIEW OF THE
SOLAR THERMAL TECHNOLOGY PROGRAM

Gerald W. Braun, Director

Division of Solar Thermal Technology

I. INTRODUCTION

The entire Department of Energy will soon be engaged in justifying its existence as part of a congressionally mandated "Sunset Review" process. The issues raised by this process are often overlooked in the day-to-day administration of programs, yet they bear an important relationship to the philosophy behind each program. This seems to be an appropriate time to consider the ideas and concepts upon which this program is predicated.

In most discussions of solar thermal technology the focus is on the details of the individual solar thermal concepts. Generally this approach is appropriate, however, it increases the difficulty of understanding the program as a whole. By considering the Solar Thermal Technology Program as a single entity, this examination will show that the program is necessary, appropriate and effective.

The current solar thermal program rests firmly on two bases; one legislative and one practical. The program was initiated by the Solar Energy Research, Development and Demonstration Act of 1974. This legislation outlined the approach that the program should take to the development of solar thermal energy and also set out specific goals for the program. The Solar Thermal Technology Program has closely followed the guidance of Congress and has pursued each of the suggested initiatives. The practical basis for the program is the concept of cost reduction through research and development. The technical feasibility of most solar thermal concepts has been established during the past several years. The need for system cost reductions is one of the major problems which has prevented widespread development and use of the technology. These cost reductions involve technical risk and can be best achieved through research and development on materials, components, subsystems and systems. Accordingly, the Solar Thermal Technology Program is stressing research and development.

II. THE SOLAR THERMAL TECHNOLOGY PROGRAM: PROGRESS AND PRIORITIES

The objective of the Solar Thermal Technology Program is to provide a financial and technical basis for the energy R&D and manufacturing industries to develop solar thermal technologies to a point which allows potential suppliers and users to make positive capital investment decisions. This objective derives from the legislation that authorized the program, the Solar Energy Research, Development and Demonstration Act of 1974. While the strategy chosen to meet this objective has been tailored over time to reflect technical progress and the reordering of programmatic priorities, this objective has remained unchanged.

The authorizing legislation sought to provide a thorough, long-term approach to the development of solar thermal energy. Specific solar thermal activities authorized by Congress included:

- The design, construction and operation of facilities and powerplants (1-10 MWe) in order to demonstrate the technical and economic feasibility of utilizing various forms of solar energy;
- The large-scale utilization of solar energy in the form of direct heat;
- The development of thermal energy conversion for the generation of electricity and the production of chemical fuels;
- The design and development of hybrid systems involving the concomitant utilization of solar and other energy sources;
- An investigation of the direct use of solar heat as a source for industrial processes;
- The utilization of thermal and all other byproducts of solar facilities;
- An examination of energy storage.

The Solar Thermal Technology Program has followed the Congressional guidance very closely and has pursued initiatives in each of the areas specified by the Act.

All of the solar thermal concepts addressed by the authorizing legislation share a common development pattern. However, in 1974 the concepts were at different points in their technical maturity. The result for the Solar Thermal Technology Program was that the technical work called for in the Act varied greatly in difficulty. To date, most of the straightforward objectives have been met, while many of the more challenging developmental efforts remain to be completed. The strategy responsible for previous program successes will be used in the development of the remaining solar thermal concepts, thus affording the program the full benefit of the experience it has gained.

The technical accomplishments of the Solar Thermal Technology Program illustrate the parallel developmental paths that the various solar thermal concepts are proceeding along, as well as the different points on those paths that each of the technologies may be found at today. Major program accomplishments include:

- The construction of a grid-connected 10 MWe pilot plant;
- The initiation of construction of a 400 kWe Solar Total Energy System which will provide electricity, process steam and heating and cooling for a knitwear factory;
- The construction and operation of eight industrial process heat systems which incorporate state-of-the-art parabolic trough technology;
- The completion of designs for Repowering, Cogeneration, Hybrid and Small Community applications; and
- The identification of solar fuel processes and laboratory and bench-scale testing of those processes showing promise.

Perhaps the most important achievement of the Solar Thermal Technology program, however, is the establishment of a parabolic trough industry. With a relatively small investment the program was able to make a significant contribution in a specific technical area and then turn the technology over to the private sector.

An implicit and often overlooked aspect of the Solar Thermal Technology Program is the important role that research and development has in cost reduction. Solar thermal energy systems are technically feasible today, however, these systems are expensive. In order for the technology to reach economic viability, low-cost materials, components and systems must be investigated and developed.

The traditional route to cost reduction has been mass production, but for solar thermal technology, research and development holds more promise. This design-to-cost philosophy results in increased technical risks. Materials and components must be pushed to their performance limits. Discovering new low-cost materials and how to get the most out of proven materials, requires an aggressive research and development program. Already, in meeting the technical challenges posed by component development, the Solar Thermal Technology Program has realized significant cost reductions in two major system types (troughs and heliostats).

Despite the substantial progress that the program has made, the need for a Federal solar thermal research and development effort remains critical. While improvements have been made in the technical and economic characteristics of the technology and an industry base is being established, the program must continue in order to satisfy Congressional intent. The designs that have been developed within the Solar Thermal Technology Program must be tested and evaluated over the next five years to ensure their workability. Many complex control and life-cycle cost issues must be resolved on existing designs before work is completed, and the information developed must be transferred to industry.

The composition of the solar thermal industry and the diffuse nature of the benefits that accrue from research and development (R&D) programs necessitates Federal involvement in the technical validation of solar thermal systems. The industry currently consists of small, highly specialized firms with limited R&D resources and small R&D groups within the divisions of large corporations. The latter groups are often in competition for corporate resources with larger R&D groups within the same division and find themselves at odds with prevailing research and management philosophies. Therefore, only a small number of firms are likely to maintain an active solar thermal R&D program in the absence of Federal involvement. Elimination of the Federal presence in this area will result in less sharable technical information. This will increase the costs and risks that each solar thermal supplier will be exposed to without a concomitant increase in that supplier's profits.

While some potential users of solar thermal systems have shown a willingness to commit matching funds in application projects, the uncertainty surrounding solar tax credits has resulted in a general reluctance to invest in solar energy. The unanswered technical, economic and Federal policy questions associated with solar thermal energy systems preclude a sufficiently large R&D investment by the utilities or by other potential users. Utility involvement is further restricted by regulatory practices which limit utility investment in energy R&D.

The objective embodied in the Solar Energy Research and Development Act of 1974, to develop the technology to the point where market forces can take over, has not yet been met. The private sector is reluctant to invest in manufacturing equipment for solar thermal energy systems until the technology has been proven on a suitable scale. With or without Federal assistance in R&D, a technology verification step is a necessary prerequisite to the initiation of mass production. At a minimum, private industry involvement in projects involving repowering, salt ponds, parabolic dishes, hemispherical bowls and fuels and chemicals will be required before the Solar Thermal Technology Program can be considered successfully completed.

The Solar Thermal Technology Program has not only coordinated solar thermal developmental efforts in this country but has helped establish the U.S. solar thermal industry as the world's leader. While alternatives to the current Federal program do exist, R&D must still precede the development of a viable solar thermal industry. Financial incentives encouraging the production and use of solar thermal systems and a reduction in subsidies currently enjoyed by fossil fuels would serve to increase interest in solar thermal technology. In such an environment, solar thermal manufacturers would be able to fund their own research efforts. The cost of the required level of incentives, however, would be far greater to the taxpayer than the current approach of cooperatively developing cost effective designs prior to attempts at mass market production of solar thermal technology.

An alternative approach would be to rely entirely on the solar thermal technology development work that has been done in other countries (principally Japan and W. Germany) and to import components and systems. This course of action would require the United States to surrender its current technical leadership role in this area, and would run counter to the stated intent of Congress.

III. THE SOLAR THERMAL TECHNOLOGY PROGRAM: A JUSTIFICATION

The Solar Thermal Technology Program grew out of the realization that new solutions are required to help meet our nation's energy demands. The fuel shortages and price escalations of the early seventies precipitated the passage legislation authorizing a long-term Federal program to provide continuity and focus to R&D on Solar Thermal Technology.

Seven years later, this objective remains unchanged and, despite the progress that the program has made, many of the conditions that led to the formulation of the Solar Thermal Technology Program still exist. Alternatives to conventional energy are still necessary in order to introduce an element of stability into the energy picture. The reduction of risks related to the cost, quality and availability of energy remains a national priority. Solar energy and other renewable energy sources have the potential of providing reliable and inexpensive energy and serving as a buffer against escalating fossil fuel prices and supply uncertainties.

Currently, manufacturers cannot achieve the near-term profits necessary to justify the investments in research and development or facilities and equipment required to produce solar thermal systems. Compounding this problem is the fact that, despite large increases over the past decade, energy costs remain a small percentage of industry's total expenditures. As a result, both users and suppliers of energy have little incentive to invest their high cost venture capital in Solar Thermal Technology systems.

The development of solar thermal energy is a major undertaking that, as Congress realized, requires the support of the Federal Government. New energy technologies capable of contributing to our nation's energy requirements consist of complex, integrated systems. The resources and talents of many organizations are necessary to provide an emerging energy technology with adequate support and coordination. At this point, major private industries are unable to make the required commitment to solar energy and the Federal Government is providing most of the necessary economic and technical stimulus.

The attributes of solar thermal systems, which spawned congressional interest in the technology in 1974, continue to make solar thermal unique among alternative energy sources. Solar thermal technology is the only renewable technology with the potential to provide energy systems which can be a true one-to-one substitute for conventional energy systems. Solar thermal systems produce heat which may be used directly or as steam, or may be converted into electricity or fuels. These products are familiar and essential inputs into the existing energy supply infrastructure and allow solar thermal energy to be employed without disrupting the current energy distribution system.

The inherent flexibility and versatility of solar thermal energy makes it the only technology capable of addressing all legislated provisions. Specific solar thermal attributes include:

- The ability to provide both thermal and electrical energy at almost any scale, from a few tens of kilowatts to hundreds of megawatts;

- The technology's suitability to retrofit applications in which solar energy supplants or supplements the heat source of existing plants (this feature should help smooth the transition to renewable energy sources);

- The capability, unique among solar technologies, of providing high-temperature heat without a chemical, mechanical or electric-to-thermal conversion step; and

- The technology's compatibility with economic thermal energy storage which allows near continuous delivery of low-cost energy.

The development of solar thermal energy will benefit far more people than is commonly realized. Between 80 and 85% of the nation possess sufficient solar resources to allow solar thermal systems to operate effectively and efficiently. an even larger portion of the country could potentially benefit from development of the technology as solar thermal manufacturing would undoubtedly occur nationwide. Direct beneficiaries will include the manufacturers of solar thermal components and systems as well as those industries and utilities which actually employ the technology. Included will be firms producing components for both domestic and export markets, as well as those firms involved in integrating and installing these systems; municipal electric utilities and rural electric cooperatives, which currently rely on a high proportion of fossil fuels as a fuel source; investor-owned electric utilities in high insolation and/or high fuel price regions; and industries using industrial process heat in high insolation and/or high fuel price regions.

The economic benefits that will be conferred on society by a mature solar thermal industry will accrue to many Americans. Specific indirect beneficiaries will include the customers of electric utilities employing solar thermal energy and the consumers of industrial goods manufactured with the use of solar process heat. Even more importantly, the widespread use of solar thermal energy systems will help stabilize energy supplies and prices thereby reducing national vulnerability to fluctuations in energy prices and availability.

The compatibility of solar thermal systems with conventional energy conversion technology, and with existing energy supply and distribution infrastructures will help lower energy costs. Further savings will accrue as the use of solar thermal energy extends the life of conventional systems through reduced fuel use and production. The negligible environmental impacts of solar thermal systems will also reduce society's costs because solar thermal installations give off no harmful effluents.

IV. SUMMARY

The Solar Thermal Technology Program was established with the assumption that the development of high-risk energy alternatives is necessary and that it is an appropriate pursuit for the Federal Government. Among renewable energy technologies, solar thermal was correctly perceived as having unique potential and was selected for development. The intervening years have not changed the quality or importance of the contribution that solar thermal technology can make to our national energy needs. As a result of the program we are much closer to realizing the benefits that solar thermal technology has to offer. Continuation of the Solar Thermal Technology program will assure that past accomplishments are capitalized upon and that technical progress in this area continues.

TECHNICAL OVERVIEW
CENTRAL RECEIVER PROGRAM

Clif Selvage
Sandia National Laboratories
Livermore, California

INTRODUCTION

When I consider the period since 1973-1974--when we initially established a set of goals--I have to observe that the Central Receiver Program has been an interesting one. Today I'd like to review with you what has happened technically in that program, from the standpoint of one who has rejoined it (who never really left it) and become active in it again. Figure 1 outlines the basic parts of the Central Receiver Program and its major activities from FY 1979 to FY 1983.

Over the next two days we'll hear about several projects:

- I'm going to concentrate on the technical development area. I will be reviewing a bit of history as well as discussing where the program stands technologically.

- In applications, we have Electrical Generation, Industrial Process Heat, Cogeneration, Repowering/Industrial Retrofit, and Fuels and Chemicals. You will receive information about all these projects except Fuels and Chemicals. I'm not going to say much about Fuels and Chemicals either; however, I do think that one of our next challenges is to develop and apply central receiver technology to that very interesting process. This application offers possibilities for satisfying another set of our nation's energy needs.

- Finally, we will talk at this meeting about several DOE-approved and proposed projects:

  - The Central Receiver Test Facility (CRTF)

  - The 10 MWe Solar Central Receiver Pilot Plant near Barstow, CA

  - The International Energy Agency project near Almeria, Spain

  - The Repowering/Industrial Retrofit PON

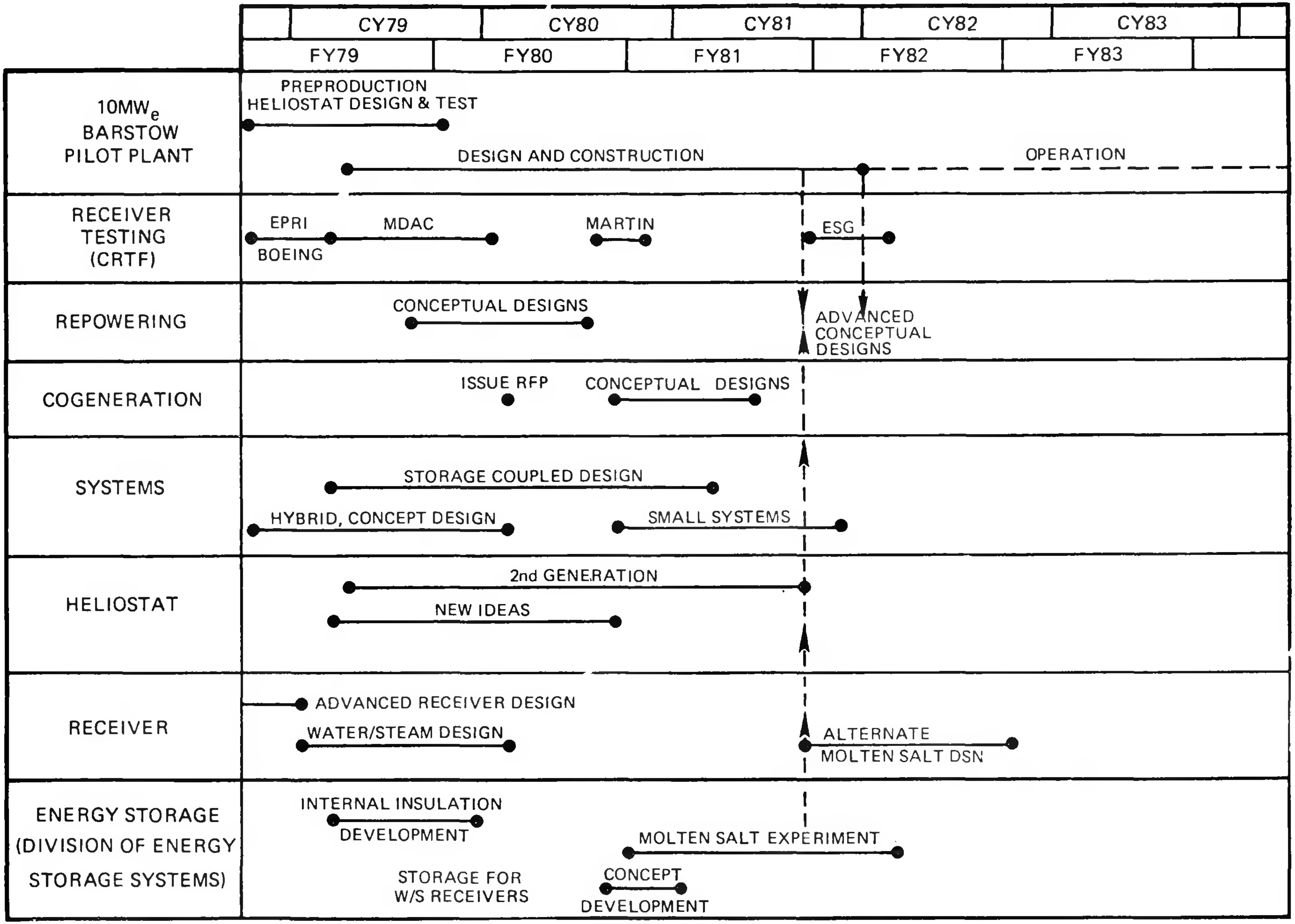


Figure 1. Central Receiver Program

- The Bureau of Reclamation/Colorado River proposed development project

Now let's get to where I really wanted to go.

TECHNOLOGY DEVELOPMENT: HELIOSTATS

In the initial stages of heliostat development, we had systems research experiments with four contractors: Boeing Engineering and Construction, Minneapolis Honeywell, Martin Marietta, and McDonnell Douglas. Four designs were built and then tested at several locations around the country. (We should note that McDonnell Douglas ended up with a different design than the one they started out with--the front surface mirror originally used an acrylic coating that didn't work out too well. As a result, McDonnell Douglas built another heliostat at their own expense and ERDA/DOE evaluated it.) After evaluations of all the heliostats were made, we wrote a pilot plant specification based on the McDonnell design. Martin Marietta won the competition for the pilot plant heliostats. Competition in the marketplace really worked; the result is seen in the 1,818 heliostats now installed at the Barstow pilot plant.

We also initiated a "New Ideas" contract to stimulate new and different ideas. We contracted Solaramics, McDonnell Douglas (who modified their pilot plant design), Boeing (who modified their plastic dome), and General Electric, and evaluated the results. We needed to concentrate on reducing costs, obtaining manufacturable designs, and understanding more clearly where we were headed--and so the second-generation heliostat effort resulted.

The second-generation heliostat contract evaluation was completed this year. A report to the public was made, presenting the outcome of the evaluation process. There are minor deficiencies in all the second-generation designs. But these problems are the sort that you, as industry, will resolve as a quality engineering and manufacturing engineering effort. The design approaches do not require additional research and development.

According to our evaluation, any one of the four designs could meet the original heliostat cost goals that we established. In a fairly realistic analysis of those costs, i.e., the cost of making heliostats at a lower quantity than we had originally forecast (25,000 as opposed to 50,000 a year), it looks as if our cost goals can be met in the range of $100 to $130 a square meter. That's significant. To me, at least, it means that we've come very close to arriving at a goal we established some time ago. This has been made possible through your efforts, those of the industrial people, perhaps with a little prodding and a little help, but certainly with a lot of evaluation and a lot of critiquing of your designs.

There are undoubtedly new ideas to investigate for their viability to drive heliostat costs down still further. We will look for those; we will continue to have an open door, an open ear, for different suggestions that could bring us closer to our original cost goals, or even to beat them.

TECHNOLOGY DEVELOPMENT: RECEIVERS

In 1977 Gerry Braun observed that heliostats would be the cost driver for central receiver systems and that the technical battleground would be in the receiver area, with working fluids and coolants. His remarks reflected the status of recent research on two different receiver designs. As I think many of you remember, the original systems research experiments (SREs) incorporated three receiver designs: two cavities and one open receiver. Since we didn't have a solar test facility then--a CRTF--we evaluated the receivers with radiant heat in several different locations. We concluded that for Barstow we would use an external design and subsequently evaluated one panel of that design at the CRTF.

Our objective in receiver technology development has been, of course, to obtain experimental data on receiver performance. We obtained data originally in the SREs with radiant heat. In early 1979 the first test run at the CRTF was completed with an air-cooled cavity receiver by Boeing with EPRI. We tested a module of the Barstow water/steam receiver at the CRTF; we also tested a five-tube receiver with radiant heat to try to understand and control departure from nucleate boiling. We have now finished testing the Martin Marietta salt-cooled receiver. A sodium receiver by Energy Systems Group (ESG) is currently under test at the CRTF.

In all of our testing, we've never really had a receiver fail. We may have had some surprises. We may have been dissatisfied with the way the tubes held, or the way things bent or reacted, or the performance that we got; but we've never really had a failure. Our designs, one might say, are conservative.

The next step, technologically, would be to try to make those designs more efficient--with thinner walls, higher pressures, higher temperatures, higher fluxes--to improve the overall system efficiency. That's the technical arena in which we can work. We will explore further the possibilities of the salt-cooled systems. If funded, we will go forward with the contracts that have been let for a design analysis of a second-generation salt receiver and thereby discover if the design can be improved at higher fluxes and at higher temperatures for better performance.

TECHNOLOGY DEVELOPMENT: ENERGY STORAGE

Our objective in energy storage technology is to develop thermal energy storage for solar thermal applications. The DOE Division of Energy Storage Systems has primary responsibility for this development. Ongoing program activities include molten salt stability and compatability experiments, and conceptual designs for thermal storage for saturated steam and superheated steam receivers. A 7 MWht molten salt experiment is currently under construction at the CRTF. By April 1982, testing of the experiment should be complete; a report will follow in June.

CONCLUSION

Our major milestones for technology development in FY 1982 can be summarized as follows:

- Heliostats

  Complete second-generation summary report (December 1981)

- Receivers

  Complete ESG sodium receiver test (February 1982)

- Energy Storage

  Complete construction of molten salt experiment (December 1981)

  Complete testing of molten salt experiment (April 1982)

  Complete report on molten salt experiment (June 1982)

Although there is no work scheduled beyond that time period, we will still be looking for ideas that can potentially drive down costs for a multitude of different kinds of systems as well as for heliostat, receiver, and storage subsystems.

10 MWe SOLAR THERMAL CENTRAL RECEIVER PILOT PLANT

R. N. Schweinberg
U. S. Department of Energy

J. N. Reeves
Southern California Edison

Introduction

The 10 MWe Solar Thermal Central Receiver Pilot Plant is a large-scale experiment which will apply the results of research and development experiments to a solar-powered electrical generation plant to provide data that will move these systems closer to technical and commercial feasibility. The technology is either in hand or has been demonstrated in experiments and test facilities, but has not previously been integrated into a full system for operation in a utility context. The primary objectives are to demonstrate technical feasibility, economic potential and environmental acceptability.

Department of Energy Headquarters responsibility for the project has been assigned to the Division of Solar Thermal Energy Systems within the Office of Solar Heat Technologies. A Solar Ten Megawatt Project Office (STMPO) has been established by the San Francisco Operations Office (SAN) with responsibility for the day-to-day planning, direction, execution and control of the project within the approved envelope of technical objectives, cost estimates, and schedule milestones. The project is a joint utility and government-funded project. The Associates, comprised of Southern California Edison Company, the Los Angeles Department of Water and Power, and the California Energy Commission, are participating in the engineering management, construction, operations, and technology transfer activities of the project, in accordance with a Cooperative Agreement between DOE and the Associates. Figure 1 is a photograph of the plant taken during the second week of September 1981. All major plant equipment had been installed as of that date.

Project Costs

Project capital costs are delineated in Figure 2 showing a breakdown by major system.

Project Schedule

Figure 3 shows the overall project schedule. Construction activities are approximately 90% complete. Plant startup has been initiated concurrent with construction completion. The next key project milestone is Turbine Roll, which is scheduled for December 1981.

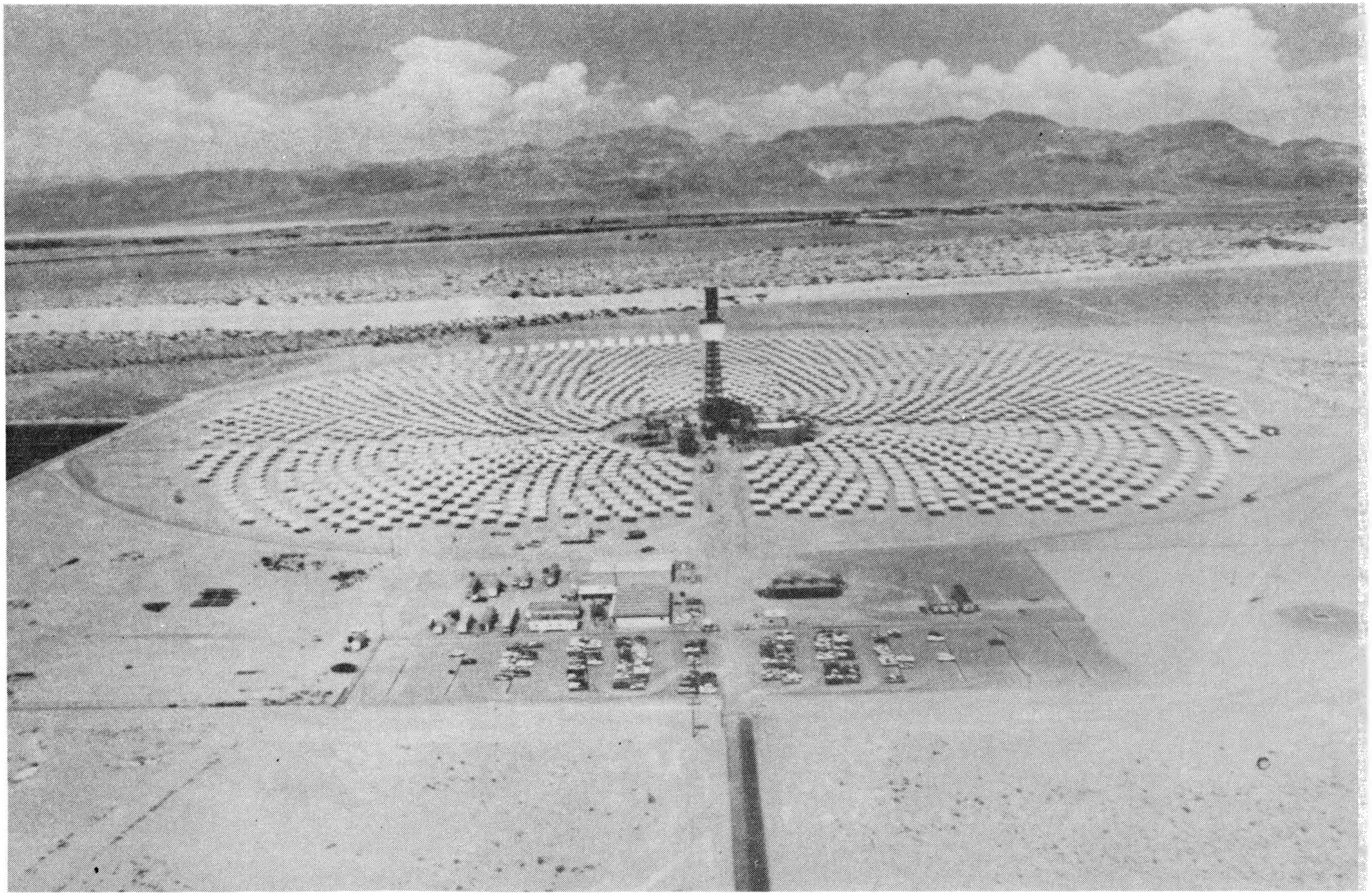


Figure 1. 10 MWe Solar Thermal Central Receiver Plant (September 1981)

SOLAR FACILITY DESIGN		$31,170,000	
o COLLECTOR FIELD FABRICATION & CONSTRUCTION	$41,365,000		
o RECEIVER FABRICATION & CONSTRUCTION	21,924,000		
o THERMAL STORAGE FABRICATION & CONSTRUCTION	10,323,000		
o PLANT CONTROL SYSTEM	3,048,000		
o BEAM CHARACTERIZATION SYSTEM	865,000		
o MISCELLANEOUS SUPPORT SYSTEMS	11,305,000		
SOLAR FACILITY FABRICATION/CONSTRUCTION COST		$88,830,000	
TOTAL SOLAR FACILITY COST			$120,000,000
TURBINE GENERATOR DESIGN & CONSTRUCTION COST			21,350,000
TOTAL PLANT COST			$141,350,000

Figure 2. Pilot Plant Project Capital Costs

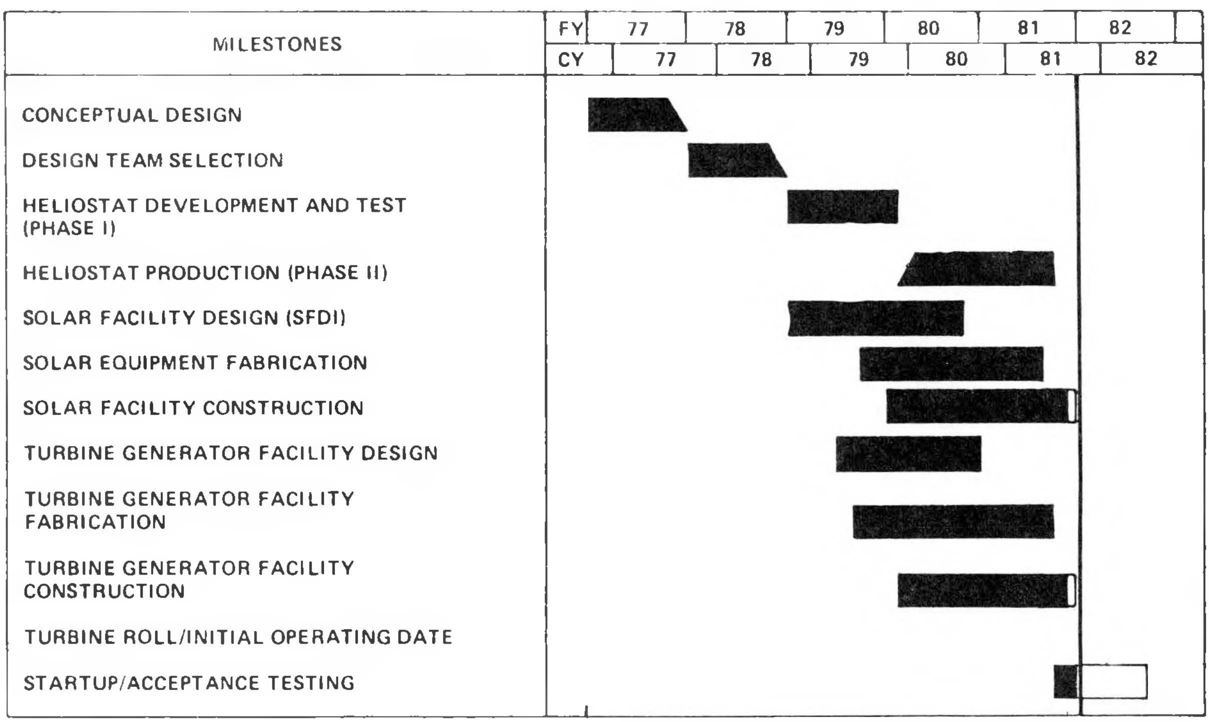


Figure 3. Baseline Milestone Schedule

Solar Facilities

DOE is responsible for funding design and construction of the Solar Facilities, including heliostats, receiver, thermal storage and master control systems. The major prime contractors are:

Martin Marietta Aerospace - Fabrication and installation of heliostats and associated controls.

McDonnell Douglas Astronautics - System integration, master control, receiver (Rocketdyne), thermal storage (Rocketdyne) and A/E services (Stearns-Roger)

Townsend and Bottum - Construction management

Accomplishments/Schedule

Accomplishments over the last year are shown in Figure 4. In summary, the site construction activities have shifted emphasis from civil to mechanical and then into electrical. Offsite fabrication is complete and all major plant equipment has been delivered. In order to accomplish Turbine Roll on an expeditious schedule, both construction completion and startup initiation are being performed in parallel as shown in Figure 5.

On October 7, 1981, velocity flushing, chemical cleaning, and steam blows of the main steam and feedwater piping loops had been completed. These activities were accomplished with temporary rental equipment.

The logic, scope and sequencing of startup activities has been established. The actual Turbine Roll date will be directly affected by the progress made at each stage of startup. Current progress is several weeks behind the Figure 5 schedule.

Costs

In December 1979, DOE approved an increase in the Solar Facilities funding from $108M to $118M. In February 1981 this additional $10M was made available to the project. One month later in March, funding was reduced to $117M because of a required reduction in DOE's budget for FY 81. The currently approved estimate for completing construction and startup thru turbine roll is $120M. In order to hold the construction costs at this ceiling the following items have been deferred:

a. Thermal storage activation
b. Plant level operational status displays software development
c. Coordinated and automatic control software development

A report containing detailed actual costs for design, hardware fabrication, and construction will be available from DOE by March 1982.

o Solar Facilities

- Site Dedication Ceremony	October 1980
- Completed Receiver Tower Erection	November 1980
- Completed Warehouse	January 1981
- Powered Up East Heliostat Field	February 1981
- Completed TSS/PSS Pipe Rack Steel Erection	March 1981
- Completed TSS Skid Installation	April 1981
- Completed Receiver Panel Installation	June 1981
- Completed Computer Console Installation in Control Room	July 1981
- Completed BCS Target Installation	July 1981
- Completed Oil Filling of TSS Tank	July 1981
- Completed Core Electrical and Mechanical Construction	September 1981
- Completed Heliostat Installation	September 1981
- Completed Chemical Cleaning and Steam Blows	October 1981

Figure 4. FY1981 Accomplishments

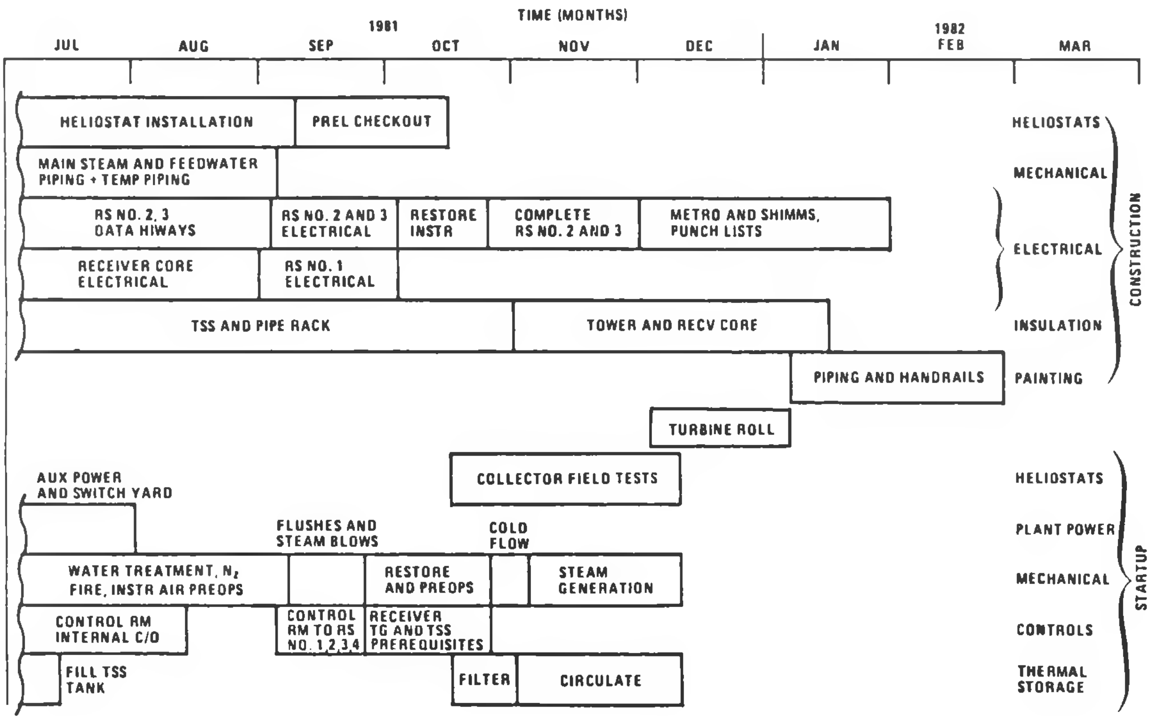


Figure 5. Pilot Plant Project Activity Schedule

Heliostats

The heliostat features are shown in Figure 6. Fabrication and installation experience by major component is summarized below:

- o Pedestals

  - Installation started November 3, 1980 and was completed June 19, 1981
  - Units installed per day were 27-60 (minimum - maximum)

- o Drives

  - Final assembly at Daggett Hangar started November 17, 1980 and was completed July 31, 1981
  - Units assembled per day were 1 - 18 (minimum - maximum)
  - Installation started November 20, 1980 and was completed August 7, 1981
  - Units installed per day were 5 - 50 (minimum - maximum)

- o Mirror Assemblies

  - Pueblo module fabrication started January 9, 1981 and was completed August 31, 1981
  - Module production was 100 - 279 (minimum - maximum) per 24 hour day
  - Final assembly at Daggett Hangar started February 16, 1981 and was completed September 10, 1981
  - Final assembly production was 2 - 18 (minimum - maximum) per 8 hour day
  - Site installation started February 20, 1981 and was completed September 10, 1981
  - Units installed per day were 4 - 40 (minimum - maximum)

- o Heliostat Controls

  - Denver fabrication started November 3, 1980 and was completed May 15, 1981
  - Installation started February 16, 1981 and was completed September 25, 1981
  - Units installed per day were 10 - 40 (minimum - maximum)

Problems encountered during the last year are summarized in Figure 7. The heliostats are currently undergoing preliminary acceptance tests as individual units. Afterwhich, the full field will be checked out, including its interface with the master control and beam characterization systems.

Based on Pilot Plant experience, Martin Marietta has recommended that the following site construction items be completed prior to the start of heliostat installations:

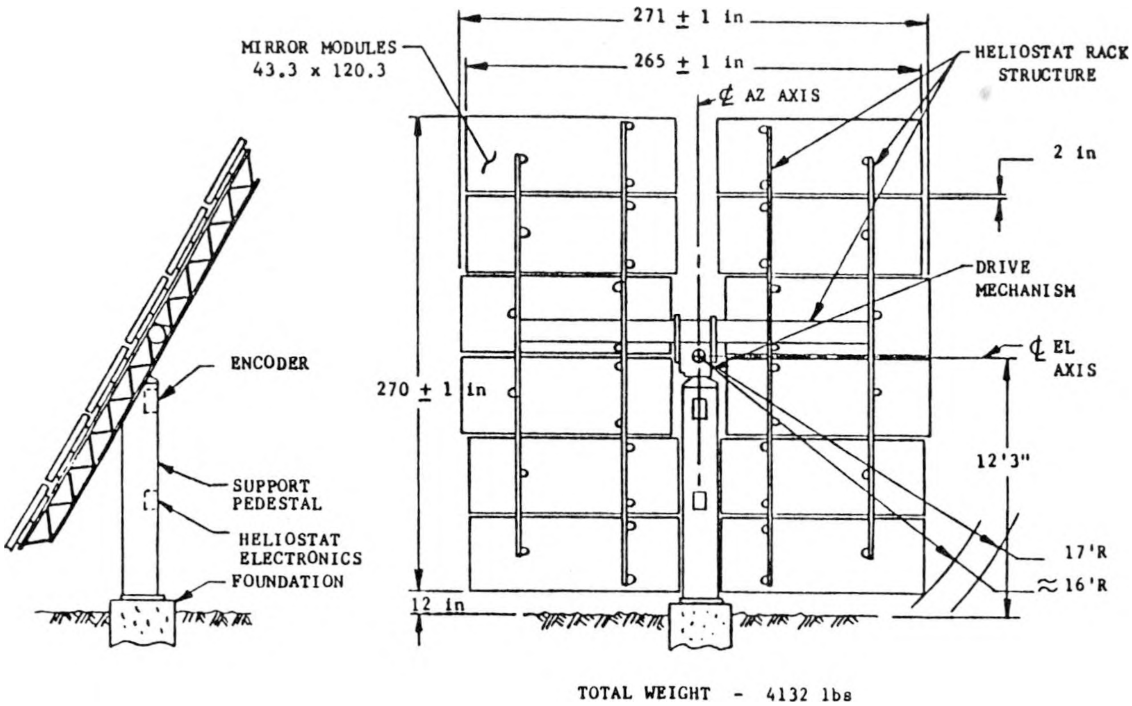


Figure 6. 10 MWe Collector Subsystem Heliostat

Problem	Resolution
- Production drive failed during simulated 90 MPH wind load test	- Additional elevation pinion gears tested without failures; High wind stow position revised to reduce loading
- High glass loss during startup of mirror module fabrication on ceramic tools	- Standard float glass used for approximately 136 heliostats; field performance impacted less than 1%
- Fifty-seven doubler pad bond failures have occurred at site. Doubler pads hold mirror modules to structural rack assembly	- Adhesive process control improved; Pad pull test initiated; riveting retrofit may be necessary; approximately 150 spare modules available at site
- Random communication failures occurred in heliostat control boxes	- Boxes modified to increase capacitor size and jumper connections added
- Lightning storm caused failure of I/O communication couplers in field and control room	- Provide additional grounding protection of control cable in core and field areas to protect against electromagnetic pulses

Figure 7. Heliostat Problems and Subsequent Resolutions

- Data cabling installed in entire field
- Power cabling energized in entire field
- Control room available for permanent control console
- BCS targets installed

Receiver

Characteristics of the once-thru to superheat external receiver are shown in Figure 8. The panel fabrication history at Rocketdyne's facilities in Canoga Park, CA and site installation data are shown below:

o Panel Fabrication

- Tube bending started February 13, 1980 and panel fabrication was completed June 1, 1981
- Shortest production time was 16 weeks for a single panel

o Panel Installation

- Installation started April 15, 1981 and was completed June 17, 1981
- Units installed per day were 1 - 3 (minimum - maximum)

There were no significant fabrication problems encountered during panel assembly Panel development work was done under an earlier DOE contract during the concept design phase in 1975-77.

Thermal Storage

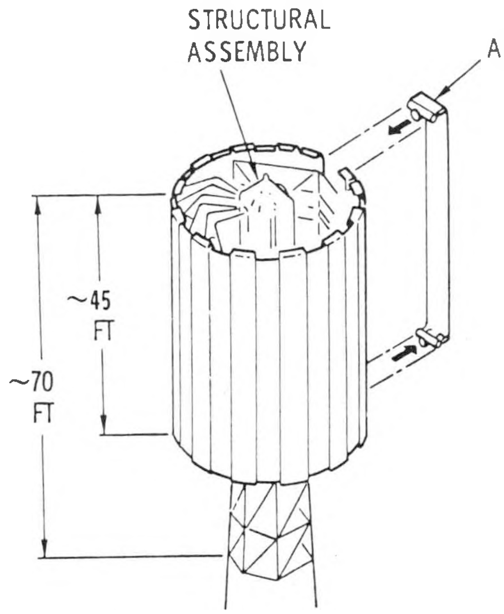
Installation of the storage tank and heat exchanger skids has been completed.

Heat exchanger skid long lead procurements were made by Rocketdyne and were supplied to a subcontractor in Long Beach for final assembly. The skids were delivered to the construction site by truck and were installed by construction crafts.

The storage tank is approximately 60 feet in diameter and 42 feet high. Both the granite/sand mixture and the Caloria HT 43 oil have been loaded into the tank. About one month after oil was placed into the tank, evidence of a leak in the floor was observed at the northern edge of the tank. Several corings have been made in the concrete foundation under the tank floor in order to find the leak location. The leak rate has remained constant at less than 1 gal/day. A special task force is considering means of plugging the leak from both inside and outside the tank. If these methods prove inadequate and if recovery of the leaking fluid is not acceptable, a tunneling effort may be employed under the floor to locate and repair the leak.

Master Control

Control architecture and site plot plan control unit locations are shown in Figures 9 and 10, respectively. Four Mod-Comp Classic 7863 computers are located in the control room and are designated as follows:



RECEIVER UNIT ASSEMBLY	
DIAMETER	~23 FT
NO. OF PANELS	
STEAM	18
PREHEAT	6
STEAM PANEL CHARACTERISTICS	
WIDTH	3.3 FT
WEIGHT	~4,000 LB
NO. OF TUBES	70
TUBE OD	0.5 IN.
TUBE ID	0.269 IN.
TUBE MATERIAL	INCOLOY 800
SOLAR SURFACE COATING	PYROMARK

Figure 8. Receiver Unit Characteristics

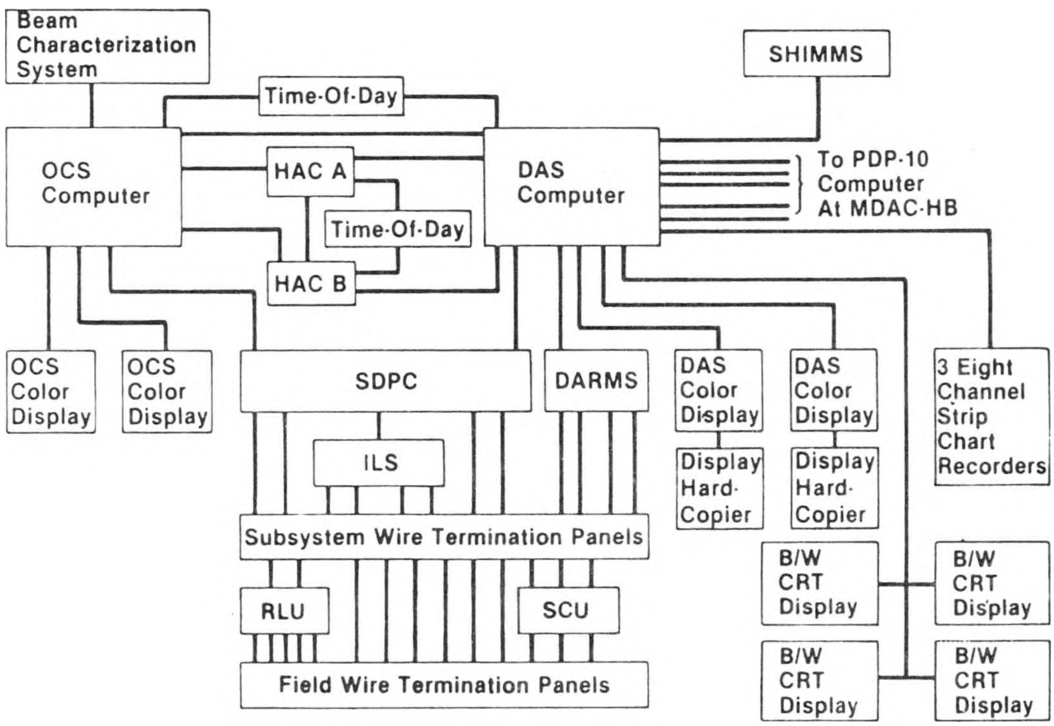


Figure 9. Baseline Control/Monitor and Evaluation Architecture

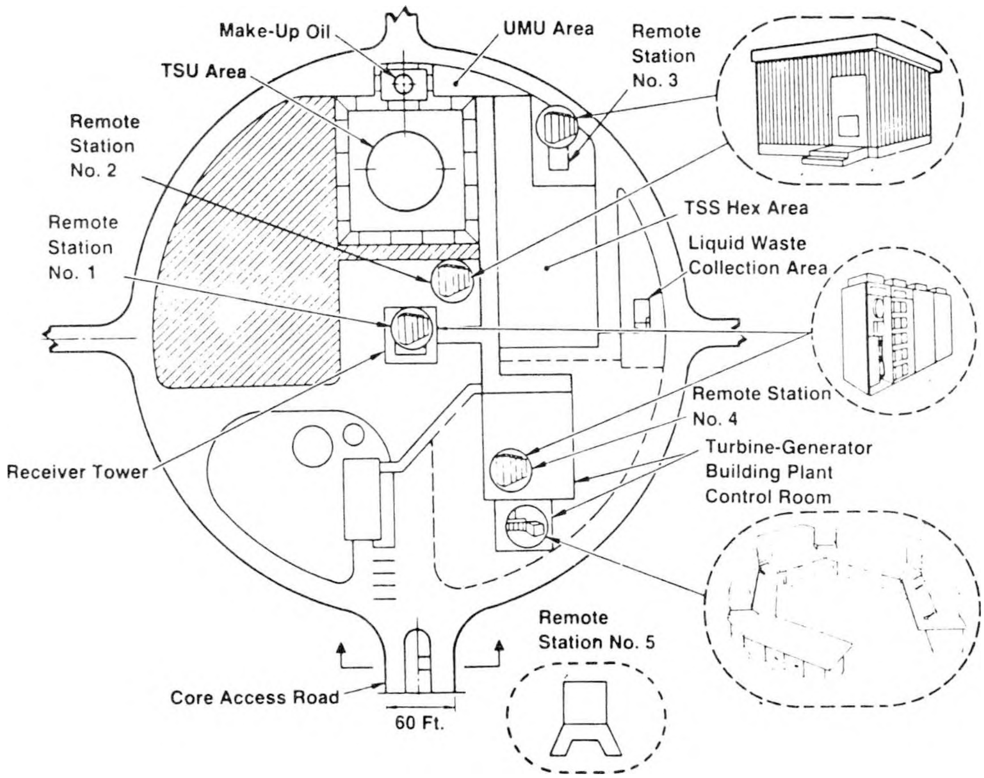


Figure 10. Site Plot Plan Control Unit Locations

A. Fabrication and Factory Test

Problem	Resolution
- SDPC data hiway throughput did not meet specification	- Redesign of hardware and firmware
- SDPC system schedules delivery to SIL slippages	- SFDI top management reviews with supplier top management
System documentation and configuration management inadequate	- Participation of quality assurance departments of MDAC and supplier
- DAS computer system delivered late	- Use MDAC computers for early software development

B. System Integration Laboratory (SIL) Test

Problem	Resolution
- Several SDPC algorithms found faulty	- Redesign of algorithms
- SDPC/computer functional interface malfunctions	- Modification of SDPC protocals and firmware
- SDPC data base security violations	- Modify firmware and change core memory type
- OCS/DAS network software did not support all selected interfaces	- Reconfigured computer systems with supported interfaces

Figure 11. Summary of Problems Encountered with Master Control Hardware

OCS - Operational Control System which provides a console for single operator control

DAS - Data Acquisition System which records selected control and monitoring data

HAC - Heliostat Array Controller which supervise the collector field. Two Mod-Comp units are utilized. One provides full redundancy for the other

Control and monitoring data is collected and processed from field instruments by way of the Subsystem Distributed Process Controllers (SDPC). This control hardware is the Beckman MV 8000 system. Five remote processing stations are located outside the control room as shown in Figure 10.

Control system hardware (exclusive of HAC's) was initially delivered to MDAC's Huntington Beach facility and configured into a laboratory simulation. Control system problems encountered during factory checkouts and simulation lab checkouts are summarized in Figure 11.

Construction

Construction is being performed under fifteen separate construction packages. Actual time spans for the major site work are shown in Figure 12. This large number of packages has required extra administrative time and effort, but has greatly contributed to reaching over 40% small business participation and over 25% minority business participation.

Turbine Generator Facilities

The Associates are responsible for funding design and construction of the Turbine Generator Facilities, including the turbine, generator, condenser, feedwater equipment, cooling loop, power transmission and control building. SCE is utilizing in-house capabilities for design and construction management services.

Engineering and Design

Since the last semiannual review, final engineering and design has been completed on schedule.

The principal activities of this period centered on procurement of the outstanding equipment, the approval of vendor equipment design drawings, the completion of the physical designs, e.g., piping arrangements, electrical circuiting, etc., with the portrayal of these designs on construction drawings, and the preparation of construction specifications. Figure 13 summarizes the major equipment procurement activities with cost data. With exception of the steam turbine generator unit and the polishing demineralizer, all equipment was received on schedule. The late delivery of the turbine/generator unit and polisher unit was accommodated by the rearrangement of construction sequences, avoiding impact to the project schedule.

Cost data is presented in Figure 14 indicating that costs are within budget.

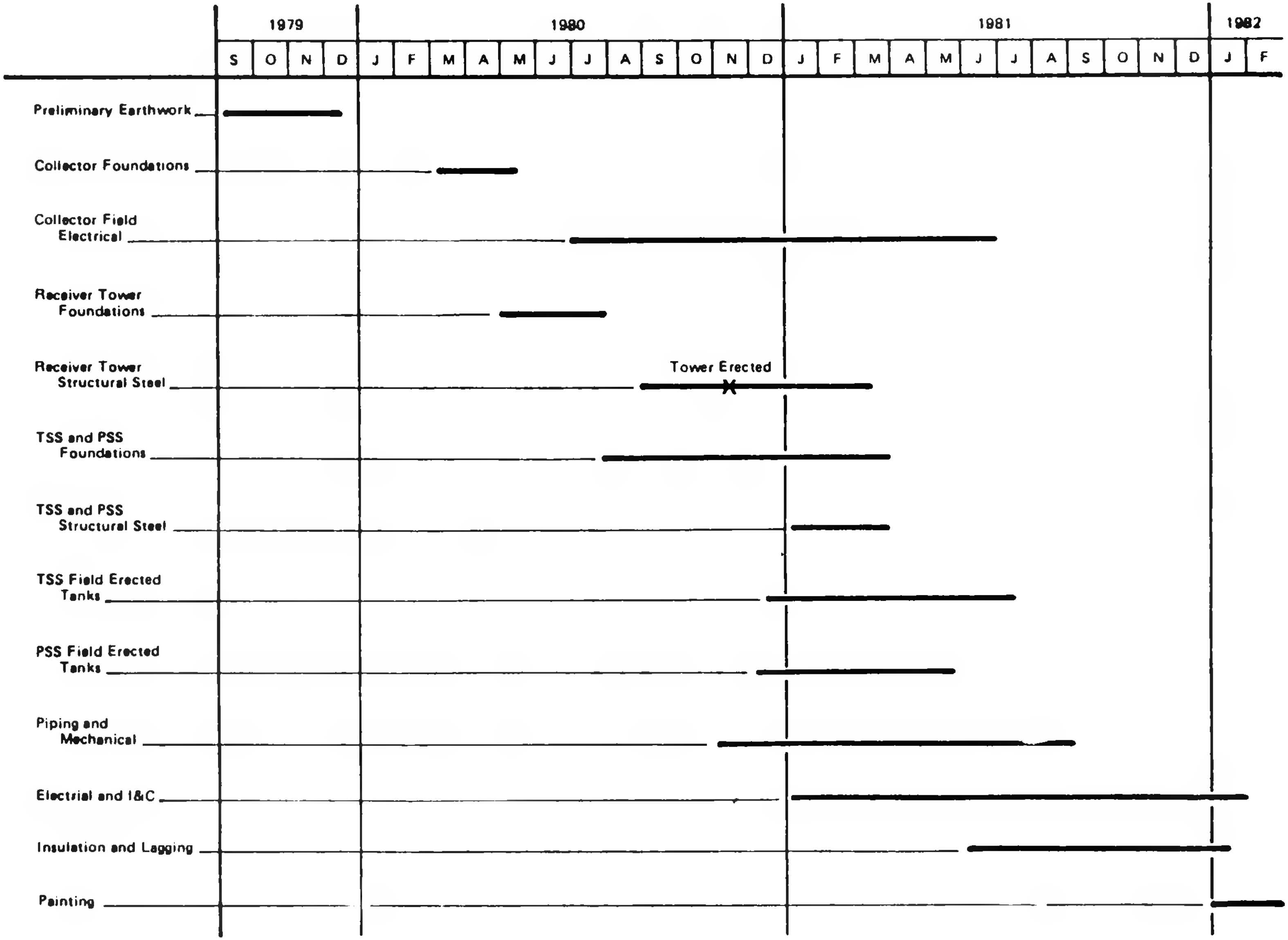


Figure 12. Construction Site Schedule

EQUIPMENT ITEM	SUPPLIER	APPROX COST
STEAM TURBINE/GENERATOR	General Electric	$\$2.2 \times 10^6$
TSS FEEDWATER PUMP	Bingham Williamette	34.0×10^3
FEEDWATER HEATERS	Struthers-Wells	127.6
DEAERATOR	Marley Co. (Chicago Heater)	32.4
POLISHING DEMINERALIZER	Crane Cochrane	247.4
CONDENSER	Ecolaire & Allegeny Ludlum	123.5
COOLING TOWER	Bac Pritchard	153.3
ELECTRIC AUX. BOILER	Hydro-Steam Industries	44.1
CONDENSATE PUMP	Peerless Pump	11.7
CIRCULATING WATER PUMPS	Peerless Pump	22.4
COOLING WATER HEAT EXCHANGE	Southwest Engineering	41.6
COOLING WATER PUMP	Peerless Pump	2.5
AIR COMPRESSORS	Gardner Denver	80.6
MAIN TRANSFORMER	Westinghouse	48.4
UNINTERRUPTIBLE POWER SYSTEM	Exide Electronics	73.6
STATION SERVICE TRANSFORMER	General Electric	20.6
480 V SWITCHGEAR & MCCS	ITE Brown-Boveri	129.0

Figure 13. Major Equipment Procurement Summary

		Incep. through Aug. 1981	Total At Completion Budget	Total At Completion Forecast
I.	Edison Manpower	$ 4,730,000	$ 4,350,800	$ 4,880,000
II.	SCE-furnished Mat'ls & Equip.	4,740,000	5,201,400	5,060,000
III.	Construction Contracts	3,580,000	5,082,700	5,060,000
IV.	Consultants & permits & Licenses	50,000	18,500	80,000
V.	T/S Field Forces	-0-	38,600	-0-
VI.	Contingency	-0-	1,658,000	1,270,000
	Subtotal	$13,100,000	$16,350,000	$16,350,000
VII.	Construction Overheads*	2,950,000	5,000,000	5,000,000
	Total Project Costs	$16,050,000	$21,350,000	$21,350,000

* All for funds used during Construction
Corp. OH
Emp. Benefits

Figure 14. Cost Data for Solar One Project

Construction

The construction work was partitioned within seven construction contract packages. These are described and the current status of each is summarized in Figure 15. The first three contracts, i.e., the civil/underground, control building erection and turbine pedestal packages were completed on schedule in December 1980, March 1981 and February 1981, respectively.

Three of the remaining four contracts: mechanical/structural, switchyard/electrical equipment and electrical wiring are currently nearing completion. The last contract, painting, will be bid in the near future.

Start-up

Southern California Edison Company, on behalf of the Associates, has the prime responsibility for management of the plant start-up activities within the start-up and acceptance test management program and organization delineated by Figure 16.

Operation & Maintenance

In accordance with the Utility Associates Cooperative Agreement with DOE, Southern Calif. Edison Co. is responsible for the operation and maintenance of the pilot plant. A prudent minimum level of staffing by experienced SCE operators has been developed based upon the following criteria: (1) the plant will be both equipment and control system intensive, (2) the plant contains unique multiple process flows, and (3) specific effort is required to identify non-conventional power plant component operating and maintenance experience.

The organization of the O&M staff, as shown in Figure 17, consists of a total of 37 full-time people, 28 of whom are represented by the IBEW. The basic operating crew, consisting of four people (Operation Foreman, Control Operator, Asst. Control Operator and Plant Equipment Operator) is consistent with normal utility practice for 24 hr/day, 7 day/week operation. The balance of the personnel will perform administrative, material control and maintenance activities. Only light maintenance capability has been provided for at the pilot plant site. Heavier maintenance can be accomplished at off-site facilities such as SCE's nearby Cool Water Generating Station. For the initial year of operation, heliostat washing will be contracted to an outside vendor until washing requirements are better defined.

The cost for a full year of operation and maintenance of the pilot plant is estimated to be $3,681,000. (1981 $'s). A breakdown of this cost estimate is provided in Figure 18.

CONTRACT	DESCRIPTION	CONTRACTOR	TERM	STATUS	COST - $
CIVIL/UNDERGROUND	Installation of undergound piping, structural foundations and cooling tower foundation	Owl Construction	Aug. thru Dec. 1981	Completed on schedule	$306,000
CONTROL BLDG. ERECTION	Construct control building	Donald, McKee & Hart, Redlands, Ca.	Sept. '80 thru Mar. 1980	Completed on schedule	741,000
TURBINE PEDESTAL ERECTION	Erect turbine pedestal and install equipment foundations	Conifer Constr. San Bernardino	Dec, 1980 thru Feb. 1981	Completed on schedule	310,000
MECHANICAL/ STRUCTURAL	Erect auxiliary equipment structure, install mechanical equipment, piping, instrumentation, insulation	Wismer and Becker Sacramento	Jan. 1981 thru Nov. 1981	92% Complete	2,500,000
SWITCHYARD/ ELECTRICAL APPARATUS	Install electrical apparatus including switchyard installation for 33 kv grid intertie	Wismer and Becker	Feb., 1981 thru Oct., 1981	98% Complete	
ELECTIRCAL WIRING	Pull & terminate power, cont. & instrumentation wiring	D. K. Nicholson San Leandro, Ca.	Apr., 1981 thru Nov., 1981	52% Complete	360,000
PAINTING	Selective painting of Appar. structures and piping		Nov. 1981 thru Feb. 1982	Contract yet to be bid	

Figure 15. Summary of Construction Contracts

Steering Committee

Chairman: J. M. Slaminski (DOE)

Members: N. J. DeHaven/
J. N. Reeves (SCE)
R. L. Gervais (SFDI)

Responsibilities

1. Set general test policies
2. Coordinate top down planning among participants
3. Assigned tasks to TWG & TAG

Test Working Group (TWG)

Chairman: L. H. Chillcott (SCE)
Co-Chairman: D. W. Christian (DOE)

Members: J. E. Raetz/D. Williams (SFDI)
R. Weeks (MMC)
F. Kovach (T&B)

Responsibilities

1. Start-up & Acceptance Test Plan Review
2. Test Implementation Schedules Review & Approval
3. Test Procedures Review & Approval
4. Start-up Manual Review
5. Management of all Start-up Activities

Test Analysis Group (TAG)

Chairman: J. E. Raetz (SFDI)

Members: J. M. Slaminski (DOE)
R&D Representative (SCE)
H. Eden (Aerospace)
R. W. Wiese (ETEC)
R. Weeks (MMC)
W. Morehouse (SNLL)

Responsibilities

1. Design Analysis Review
2. Test Data Analysis Review
3. Prepare Test Recommendations
4. Recommend Necessary Design Changes
5. Solutions to Operating Problems
6. Review Start-up and Acceptance Test Report

Figure 16. Start-Up and Acceptance Test Management Diagram

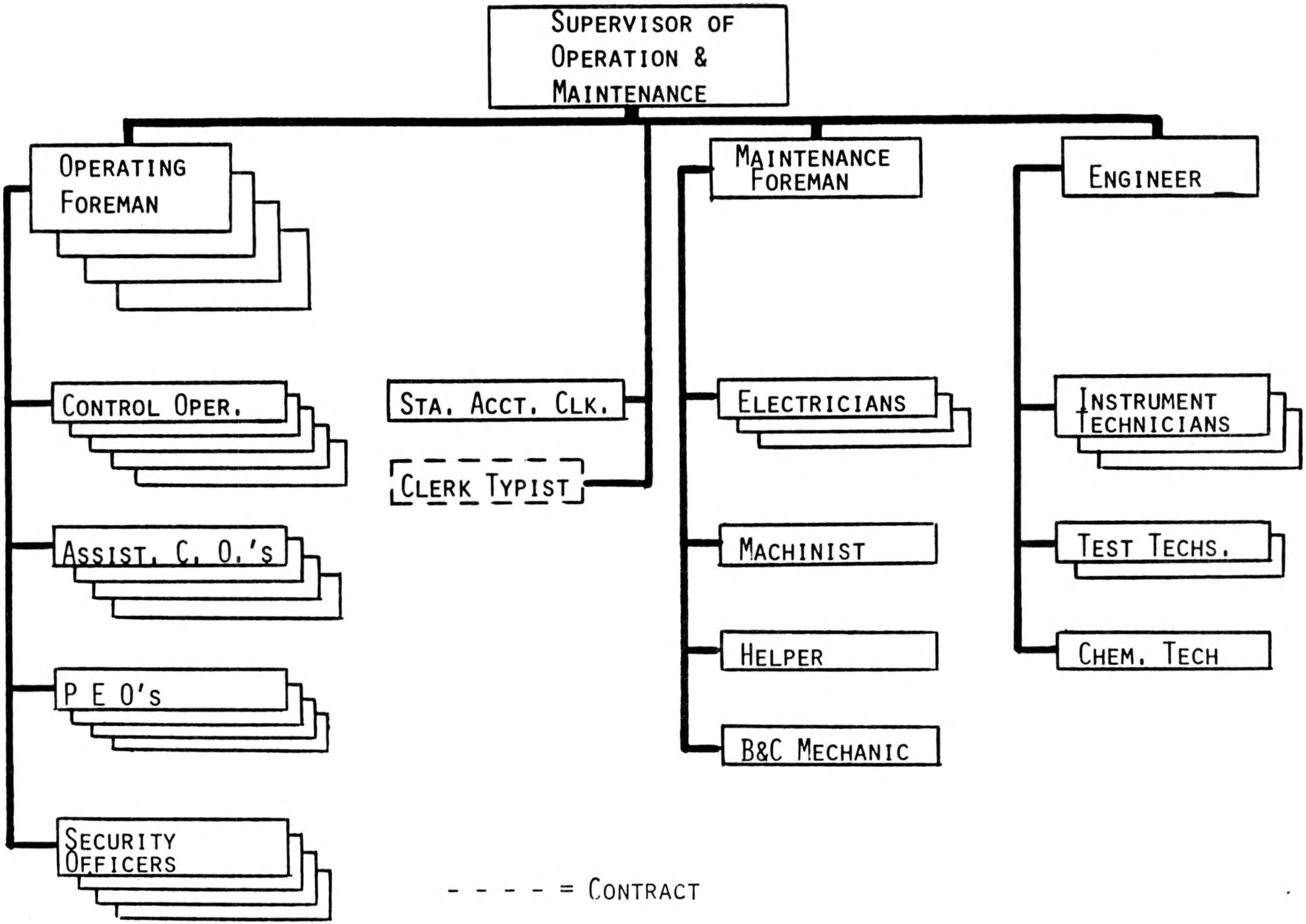


Figure 17. Solar One Operation & Maintenance Organization

1.	COMPANY LABOR	$1,377,600
2.	ON SITE CONTRACTORS	157,900
3.	OPERATING SUPPLIES & SERVICES	374,000
4.	MAINTENANCE SUPPLIES & SERVICES	242,000
5.	OFF SITE REPAIRS	231,000
6.	OVERHEADS	1,298,000
	1981 TOTAL ANNUAL COST	$3,680,500

Figure 18. Solar One Annual Budget Breakdown

BARSTOW OPERATIONAL PLANS

S. D. Elliott, Jr.
San Francisco Operations Office
Department of Energy

As the 10 MWe Solar Thermal Central Receiver Pilot Plant - "Barstow" in short, from its location - approaches completion, planning is underway for its operation over the next five years as a joint undertaking between DOE and the Associates - led by the Southern California Edison Company, with support by L.A. Department of Water and Power and the California Energy Commission. The organizational arrangement will be similar to that in the current construction completion phase, with a joint DOE/SCE on-site project office, plant operation and maintenance by SCE forces and contractors where appropriate, and technical support — including availability of solar subsystem designers and suppliers for consultation — through Sandia Laboratories.

The project objectives remain essentially unchanged - there have, however, been some changes in emphasis, and in allocations of responsibility. In a time of extreme financial stringency, the administration has taken the approach of shifting most of the responsibility - and cost - for demonstration and application of this decade's new energy technologies toward the private sector, while federal resources are directed - on a reduced scale toward riskier, but higher-payoff, approaches for the 1990's and beyond. (As a taxpayer, I have to applaud this approach, even if I've gotta take some lumps as a Federal Technocrat.) Solar One provides an outstanding opportunity to do both.

To get there, it is planned to start with an experimental - really, more of an extended startup - phase lasting about two years, in which we learn how to operate the plant to produce the most energy over the year at the least operating and maintenance cost - and how to do even better with a "Solar Two." At the end of this period, one or two operators will suffice to supervise the plant, through a fully automatic, coordinated control system, day-in and day-out, clear or cloudy, as it milks the last kilowatt-hour out of the available sunlight. This is a complex process involving many more possible combinations and transitions than in any conventional power plant. During the initial phase, then, we will be working the plant through a sequence of tests of increasing complexity. Don't try to read this - unless you've brought your binoculars or a magnifying glass. What I'm trying to show - besides satisfying you as to how we're spending the next couple of years, is the progression from operation under relatively benign, steady state conditions (like, around Noon on a clear summer day), through the transitions needed to warm the plant up, get it running, and shut it down on a "good" working day - with the attendant "Murphy's" - to the point where the operator can cope with real days - with clouds and varying demands. We've reserved some time here for simulating special applications - such as repowering - that you or we may be interested in, to guide us on our respective near- and further -term paths.

Then, having, as it were, gotten to know the plant and how to operate it with the least effort for the most output, we plan to spend up to three years more grinding out kilowatt-hours and determining the real costs of operations and maintenance, reliabilities, weaknesses in the systems to be corrected in later editions, and all the other factors on which the "real world" - the private sector - must base its investment decisions.

In all the foregoing, I have been deliberately vague as to costs, schedules and precise allocation of responsibilities. This is because we are currently in a period of very intense and rapid learning:

- What the plant is, as we start up its various systems
- How far our available resources will stretch for construction and startup activities beyond bare "turbine roll"
- Whether we will be able to get the storage system - essential to low-risk high capacity factor operation - on line early in the startup process
- How - and when - DOE and our partners can share our constrained resources to bring the more sophisticated control software and other ancillaries into being
- And - finally - just how rapidly we progress in working through the test schedule I just showed you.

All of these issues are under scrutiny and discussion and we will be reaching - and announcing - our conclusions as we develop them over the next few weeks.

For now, come on out to Barstow Thursday and look over our plant. I'm sure you'll find it as impressive and exciting "in the flesh" as we do.

Thank you.

ENVIRONMENTAL STUDIES IN THE ENVIRONS OF THE
10 MWe STPS PILOT PLANT*

R. G. Lindberg and F. B. Turner

Laboratory of Biomedical and Environmental Sciences/UCLA
900 Veteran Avenue, Los Angeles, California 90024, U.S.A.

Introduction

The spirit of the U.S. National Environmental Policy Act is to protect, restore and enhance the quality of the human environment. In this broad context a solar thermal power system (STPS) appears as an environmentally benign technology. Nevertheless, there are site specific environmental concerns which must be addressed. These are primarily in the areas of land-use, ecological effects, and water supply. This paper provides an environmental perspective to siting large scale STPS in arid regions, and describes on-going environmental studies in the environs of a small 10 MWe STPS pilot plant currently under construction.

Early deployment of large scale central receiver STPS in the United States most probably will occur in relatively undeveloped arid regions where insolation rates are high (5-7.2 KWhr m^{-2}) and land relatively available. The limiting factor to siting STPS in the desert appears to be the very trait that produces a desert--lack of water. All known and available water in the west is fully allocated and water delivery costs are currently underpriced. Furthermore, desert ecosystems are dependent on a delicately balanced water budget. The potential for an STPS to disrupt a desert ecosystem is high if water is drawn from the vicinity of an STPS to meet cooling requirements.

Desert areas are frequently looked upon as non-productive wastelands less sensitive to environmental disturbance than other areas. Environmentalists and ecologists disagree, however, and protest that such environments are unique and that plants and animals which occupy the desert are highly specialized members of a particularly fragile ecosystem. In addition, greater numbers of people have begun to use the desert as a recreational area, and pressure has increased to maintain the aesthetic state unique to the desert. The U.S. Bureau of Land Management, in response to such interest, has developed a desert management plan which includes identification of areas for protection under the National Wilderness Protection Act. Military reservations, Indian lands, and railroad right-of-ways further partition the apparently continuous desert expanses. Consequently many convenient and large tracts of land with usable water and acceptable transmission line corridors may not be available.

---

* Supported by Contract No. DE-AM03-76-SF0012 between the U.S. DOE and the University of California

Since solar thermal power systems are unproven technologies, uncertainties exist regarding their real environmental impacts. Environmental concerns include i) acquisition and alteration of land, ii) effects of construction, iii) availability of water and possible influences of waste water on the environment, iv) management of thermal transfer and storage fluids and accidental releases, v) production of NO_x and ozone around the receiver, vi) glare and misdirected beams from heliostats, and vii) micro- to mesoclimatic changes and attendant ecological effects (Davidson and Grether, 1977; ERDA, 1977; Turner, 1980).

The U.S. Department of Energy, the Southern California Edison Company, the California Energy Commission, and the Los Angeles Department of Water and power are cooperating in the construction and operation of a 10 MWe STPS pilot plant. The site is in the western portion of the Mojave Desert in San Bernardino County, California. The plant site is bordered on the east by a representative section of Mojave Desert ecosystem. Construction of the STPS presents an opportunity to validate anticipated environmental effects, and to obtain quantitative data that might be scaled to the environmental assessments of larger future STPS.

Environmental Studies in Progress

Physical and chemical analyses of the soil and determination of the plants and animals occupying the area were done in 1978 and 1979 to i) provide a baseline against which to compare changes during facility construction and operation, and ii) to prepare for restoration of the site following facility decommissioning (Turner, 1979). This environmental characterization was used to define a monitoring plan for the construction and operation phases. Our program of biological monitoring does not embrace the total ecosystem, but is tailored to a few particular organisms which include common plants and animals distributed with reasonable uniformity over the area adjoining the heliostat field.

A major problem in interpreting biological observations is that populations of desert organisms experience natural changes from one year to the next owing to differences in rainfall and temperature. Such changes include growth and production of shrubs, numbers and kinds of annual plants germinated, and densities of various populations of animals. Therefore, a series of observations in a single area will shed little light on possible influences of the STPS because such effects are confounded by natural fluctuations. This problem is being met by making comparisons over time in paired plots shown to be similar before construction. Such a design assumes that, if construction and operation of the facility affect conditions beyond the mirror field, the effects will be more strongly expressed in areas near the field than in those at a distance. The detection and interpretation of divergences in paired areas is the basic rationale of the off-field monitoring program.

Construction of the power plant began in the fall of 1979. The profound effects of clearing, grading and compacting were obvious and predictable. It was less clear what to expect in areas adjoining the site. We suspected that large amounts of dust and sand would be blown into areas east (downwind) of the prospective heliostat field when the area was cleared and graded. Special collecting devices were placed on the ground at six sites east of the field. These devices measured fluxes of windblown sand at five levels above the ground (from 1 to 36 cm). The meter at the northeastern corner of the field was unable to capture all windblown material during the first phases of grading. The flux was much reduced 200 m farther north. If we assume the diameter of the heliostat field to be 800 m, the measured loss rates indicate that roughly 160 metric tons of sand were removed from the field between mid-October 1979 and March 1980. If all of this were evenly deposited in a sector extending to 100 m from the field's eastern edge, new deposition would be about 11 metric tons ha^{-1}. However, sand deposited downwind of the field was not uniformly dispersed, but formed mounds in wind shadows of shrubs. Mean increase in mound height was 21.5 cm between 35 and 50 m downwind of the field, but less than 1 cm between 90 and 100 m downwind. These observations are consistent with aerial photographs which show a corona of newly deposited sand extending about 100 m from the edge of the field. The surface of the heliostat field appears to be stabilizing, but new material continues to be collected in the meters. Whether the source is the mirror field or redistribution of old material is uncertain.

The new sand affected germination of some kinds of annual plants in the spring of 1980, but those which did grow attained larger sizes than those in unaffected areas. The fate of the displaced sand is being followed closely, not only for ecological reasons, but also because this unstable material may be a source of abrasive particles that could be blown back into the heliostat field. This problem could be further aggravated by resuspension of sand particles by vehicular traffic (Lindberg and Perrine, 1981). No effects on vertebrate populations or shrubs occupying downwind areas have been observed.

Clearing and grading completely denuded the site. The pilot plant surface is a compacted bare soil covered with light gravel. New colonists will experience specialized microhabitats beneath heliostats (Patten and Smith, 1980). We plan to make micrometeorological measurements within the heliostat array preparatory to establishing test plots of different types of vegetation to help stabilize the soil surface (Romney, Wallace, and Hunter, 1979).

Health and safety aspects of glare and misdirected radiation appear manageable through proper operation and maintenance procedures (Brumleve, 1977; Holmes, 1981). The effect of reflections on local wildlife,however, is less certain. We expect considerable public interest in possible effects of plant structures on birds. An appreciable literature dealing with bird mortality around television towers has grown up during the past 20 years (Avery, Spring, and Cassell, 1978). The tower at the pilot plant is not tall (100 m) when contrasted with others studied, but the tower and associated heliostats may cause some mortality of migrants and resident species. We are monitoring bird kills and looking for evidence of birds using heliostat support structures for roosts or nests.

Extensive meteorological measurements relating to performance of the STPS are planned in conjunction with systems testing. The highest priority measurements have been defined as direct insolation, wind speed, cloud shadow pattern, wind direction, dry bulb temperature, dew point temperature, and hail formation. Lower priority measurements include circumsolar radiation, atmospheric turbidity, barometric pressure, precipitation, and global insolation. On the other hand, in terms of potential environmental effects, rainfall, soil moisture relations, and evapotranspiration compose a critical group of variables to the local ecology. These are included as a part of our monitoring program. It is also important to understand how changes in the microclimate of the heliostat field may influence conditions beyond the boundaries of the plant site.

Qualitative and quantitative predictions of micro- to mesoclimatic changes in a heliostat field have been based on assumed alterations of albedo coupled with effects of helisotats on normal air flow (ERDA, 1977; Davidson and Grether, 1977; Bhumralkar, Slemmons, and Nitz, 1980). All of these evaluations have involved very large systems (≥100 MWe), and not all are in agreement.

Changes in microclimates beyond the boundaries of the STPS could be induced by downwind deposition of windblown material (thus affecting albedo and/or soil temperature-moisture regimens), or by the presence and operation of the power plant. How the normal atmospheric boundary layer profile will be altered by movement of air across an array of 1,818 heliostats 6 m in height cannot be clearly predicted, but effects will probably not be expressed more than 15 m above the ground surface. Conventional bluff body theory predicts that normal air flow is recovered within a distance of 30 times obstruction height (Black and Veatch, 1977; Simiri and Scanlan, 1978), but there is no theory really adequate to predict effects of an array of structures as complex as the heliostat field. After construction we will have boundary layer profiles measured upwind of the heliostat field and at three distances downwind--in the "wake" of the field. The downwind and vertical distribution of mean wind speed and turbulence intensity may be estimated from these measurements (Zambrano, 1980). Our principal objective is to make empirical micrometeorological measurements on the downwind side of the heliostat field and to use these measurements to evaluate predictions as to ecological effects of STPS. We do not expect to observe conspicuous changes. However, it is important to establish either the absence of measurable change, or the magnitude of differences. Changes will likely be mirrored in the local ecosystem. Furthermore, we must look ahead to the construction of larger, 100 MWe STPS, and attempt to extrapolate from our experience with a smaller system.

The pilot plant will use water/steam as working fluids, and environmental concerns associated with such fluids are understood. However, the thermal storage subsystem for the facility will include a 3,340 m^3 tank filled with rocks and 770 metric tons of heat transfer oil (Caloria HT43, manufactured by Exxon Corporation). During operation, temperature of the oil will range from 218 to 304°C. Caloria HT43 has low volatility and a high flash point. When used as prescribed the danger of fire or explosion is very low. Normally only small amounts of Caloria HT43 would be released to the environment, but the possibilities of equipment failures or improper disposal procedures need to be considered.

Determination of plant toxicity threshold levels of several heat transfer and storage fluids have shown that toxicity is a function of both concentration and soil type. Effects of Caloria HT43 on barley seed germination and seedling growth were examined in one organic and three mineral soils. Signs of toxicity, in general, did not appear in mixtures containing less than 5.0% Caloria HT43. In two mineral soils Caloria HT43 even had a slightly stimulatory effect up to concentrations of 6.8 and 13.5%, respectively (Nishita and Haug, 1981; Nishita, 1980). Field experiments to determine the fate of fluids released to the environment are also being carried out involving controlled spills on bare soil, and the release of Caloria HT 43, over branches and foliage of desert shrubs.

Conclusions

1. The 10 MWe STPS pilot plant is the largest central receiver solar thermal power system in the world and the first to be constructed in the United States.

It is important to validate possible environmental effects projected for such facilities in preparation for environmental assessments of much larger systems.

2. The principal environmental effects associated with construction observed to date have been i) the complete destruction of the ecosystem within the power plant site, ii) the displacement of an estimated 160 metric tons of windblown sand from the heliostat field into adjacent downwind areas, and iii) reductions in numbers of some annual plants in areas of maximal sand deposition. No effects on vertebrate populations or shrubs occupying downwind areas have been observed.

3. Deposition of windblown sand adjacent to the site represents a threat to the integrity of heliostat surfaces. It is loose, easily mobilized, material which is likely to require a long time to stabilize in a desert environment. It may be desirable to establish a "controlled access" area adjacent to the site to enhance stabilization processes and reduce resuspension of materials. Such an action carries with it the implication of significant increases in land requirements for solar thermal power systems.

References

Avery, M. L., P. F. Spring and J. F. Cassel (1978). The composition and seasonal variation of bird losses at a tall tower in southeastern North Dakota. American Birds, 32, 1114-1121.

Bhumralkar, C. M., A. J. Slemmons and K. C. Nitz (1980). Numerical study of local/regional changes caused by a large solar central receiver power plant. U.S. Department of Energy Report DOE/CS/20537-1, SRI International, Menlo Park, California.

Black and Veatch, Electric Power Research Institute (1977). Environmental assessment of solar energy power plants. EPRI Report RP955-1.

Brumleve, T. D. (1977). Eye hazard and glint evaluation for the 5-MW_t solar thermal test facility. Sandia Laboratories Report SAND-76-8022, Albuquerque, New Mexico, and Livermore, California.

Davidson, M., and D. Grether (1977). The central receiver power plant: an environmental, ecological, and socioeconomic analysis. Lawrence Berkeley Laboratory Report LBL-6329, University of California, Berkeley.

Energy Research and Development Administration (1977). Solar program assessment: environmental factors. U.S. Energy Research and Development Administration Report ERDA 77-47/4.

Holmes, J. T. (1981). Heliostat operation at the central receiver test facility (1978-1980). Sandia National Laboratories Report SAND81-0275.

Lindberg, R. G. and R. L. Perrine (1981). Environmental effects of solar thermal power systems. Environmental considerations in siting a solar-coal hybrid power plant. I. Environmental assessment. U.S. Department of Energy Report UCLA 12/2182, University of California, Los Angeles.

Nishita, H. (1980). An assessment of plant toxicity threshold of several heat transfer and storage fluids and eutectic salts. U.S. Department of Energy Report UCLA 12/1264, University of California, Los Angeles.

Nishita, H., and R. M. Haug. (1981). Mineralization of carbon during moist incubation of soil JF79 treated with organic heat transfer and storage fluids. U.S. Department of Energy Report UCLA 12-1284, University of California, Los Angeles.

Patten, D. P., and S. D. Smith (1980). Microenvironmental changes and plant responses due to shading and wind deflection by solar collectors: a simulation study. U.S. Department of Energy Report UCLA 12/1268, University of California, Los Angeles.

Romney, E. M ., A. Wallace, and R. B. Hunter (1979). Revegetation studies pertinent to the Barstow 10 MWe pilot solar thermal power system and to potential power plant sites elsewhere in the Mojave Desert. U.S. Department of Energy Report UCLA 12/1224, University of California, Los Angeles.

Simiri, E., and R. H. Scanlan (1978). Wind effects on structures. John Wiley and Sons, New York.

Turner, F. B. (ed.) (1979). Ecological base line studies at the site of the Barstow 10 MWe pilot solar thermal power system. U.S. Department of Energy Report UCLA 12-1223, University of California, Los Angeles.

Turner, F. B. (1980). Environmental issues and solar thermal power systems. In: Proceedings 26th Annual Meeting, "Life Cycle Problems and Environmental Technology". Institute of Environmental Sciences, Philadelphia, Pennsylvania.

Zambrano, T. G. (1980). Assessing the local wind field with instrumentation. AeroVironment Inc. Report AV-FR-9572, Pasadena, California.

THEMIS STATUS

F. Pharabod
Electricité de France, REAM, Targasonne

Background

Objectives

The 2.5 MW THEMIS solar plant is the first fitting out of the so called Centre National d'Essais Solaires (CNESOL), french solar test facility layed out at Targasonne, Pyrénées Orientales.

THEMIS project is part of the research program to diversify energy resources. The principal objectives are as follows :

- to establish the technical feasability of solar thermal central receiver plant at a size that can allow reasonable scaling to a commercial size,
- to experiment the solar thermal plant to improve the main components and collect technical data,
- to indicate the potential economic operation of solar plants in France and in foreign countries.

Organisation

Solar Thermal Central Receiver plants have been studied since 1975 by the Centre National de la Recherche Scientifique (CNRS), Electricité de France (EDF) - Direction des Etudes et Recherches (DER), and CETHEL (industrial associates). The first demonstration was made at the Odeillo Solar furnace in 1976 with a small scale integrated system.

In 1979 French government decided to assign responsability for the project to the Commissariat à l'Energie Solaire (COMES) and to EDF - Région d'Equipement Alpes Marseille (REAM), in charge of the construction of nuclear and hydraulic power plants in the south of France.

The plant will be operated and maintened by EDF - Groupe Régional de Production Thermique Méditerranée, with a team of 24 persons. CNRS and EDF-DER will experiment THEMIS and collect data.

Costs

The overall project capital cost of F 128 millions is divided between the COMES (33 %), the Department of Pyrénées Orientales and Region of Languedoc - Roussillon (10 %), and EDF (57 %). COMES is funding the solar facility (heliostats and tower), local authorities are funding road and site adaptation, EDF is funding the thermal plant (receiver, storage, EPGS, control, ...).

The cost of the principal subsystems is roughly as follows :

- earthwork and buildings	25 %
- field of heliostats	30 %
- receiver and storage	15 %
- EPGS	15 %
- electrical and control subsystem	15 %

Activities During Past Twelve Months

Civil Construction Activities

- Heliostats foundation and pedestals have been erected from july to november 1980. Each foundation is 2.8 x 2.8 x 0.6 m of concrete, the pedestal is a cylinder of 0.65 m diameter reinforced concrete. We have had some difficulties for earthwork and foundation in very wet parts of the field.

  The field lay out is adapted to the site (42°5 North, mean slope of 15 %) and to the cavity receiver 4 x 4 m at 80 m above ground level, in order to minimize losses : field efficiency reaches 0.96 at equinox noon. (photo 1).

- The 8 m diameter concrete tower has been erected from august to novemver 1980, using a continuous technology.

  Structural steel for the receiver subsystem has been installed at the top the tower from june to august 1981.

- The EPGS building (25 x 70 x 18 m), including storage subsystem, has been erected from october 1980 to april 1981. This building includes a bridge-crane of 20 tons.

  Unfortunately, bad weather came too early in winter 1980-1981 obliging to stop construction of the tower and buildings (site is 1 600 m above sea level).

- Construction office has been completed in october 1980.

- Visitor center has been erected from may to september 1981.

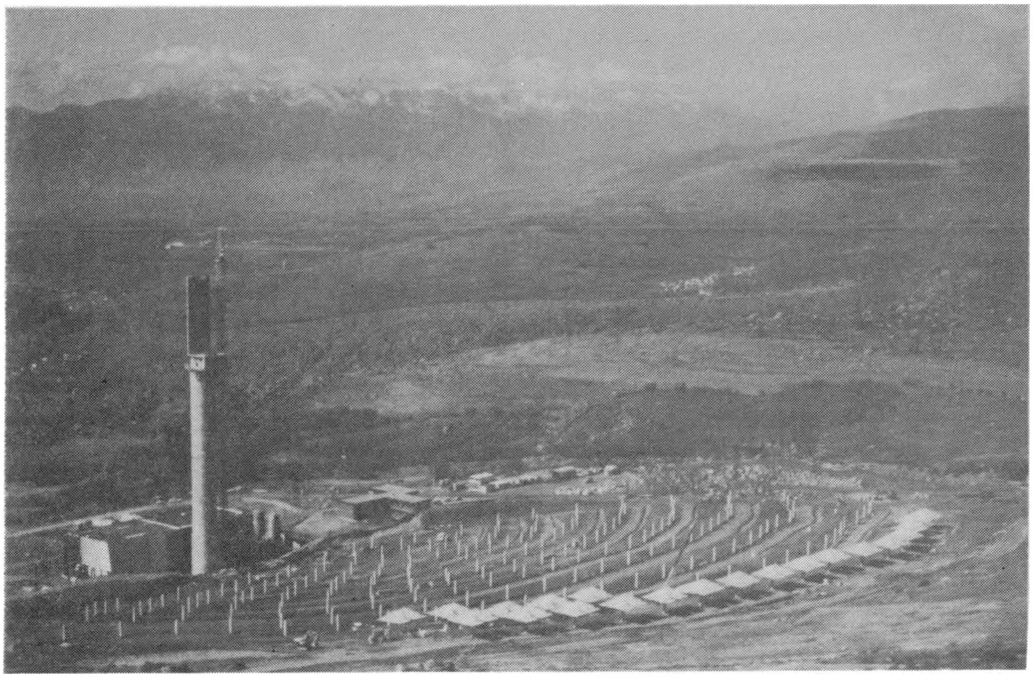


Fig.1 Collector field construction   April 1981

Collector Subsystem

The 200 CETHEL heliostats of 54 m^2 have been assembled and installed on the pedestals from april to june 1981, proceeding successfully as planned.

The focal length of each heliostat is obtained by construction, without adjustment on site :

- each of the 9 mirror modules, using float glass mirror 2 mm thick stick on 5 mm float glass (0.9 reflectivity) is focused by machine-finishing of supports.

  Five different focal length are selected for modules.

- each module is assembled on the support structure by three screw-bolt, adjusted with air level to realize calculated slopes. Twenty five different focal length are obtained for heliostats.

The image given by each of the 200 heliostats have been controlled in july-august 1981 ; some of the heliostats have been re-adjusted. The active target using 1 024 solar cells has been installed in june 1981. It will be used for beam characterisation and acceptance tests of heliostats.

Individual controllers and field controllers have been installed in july.

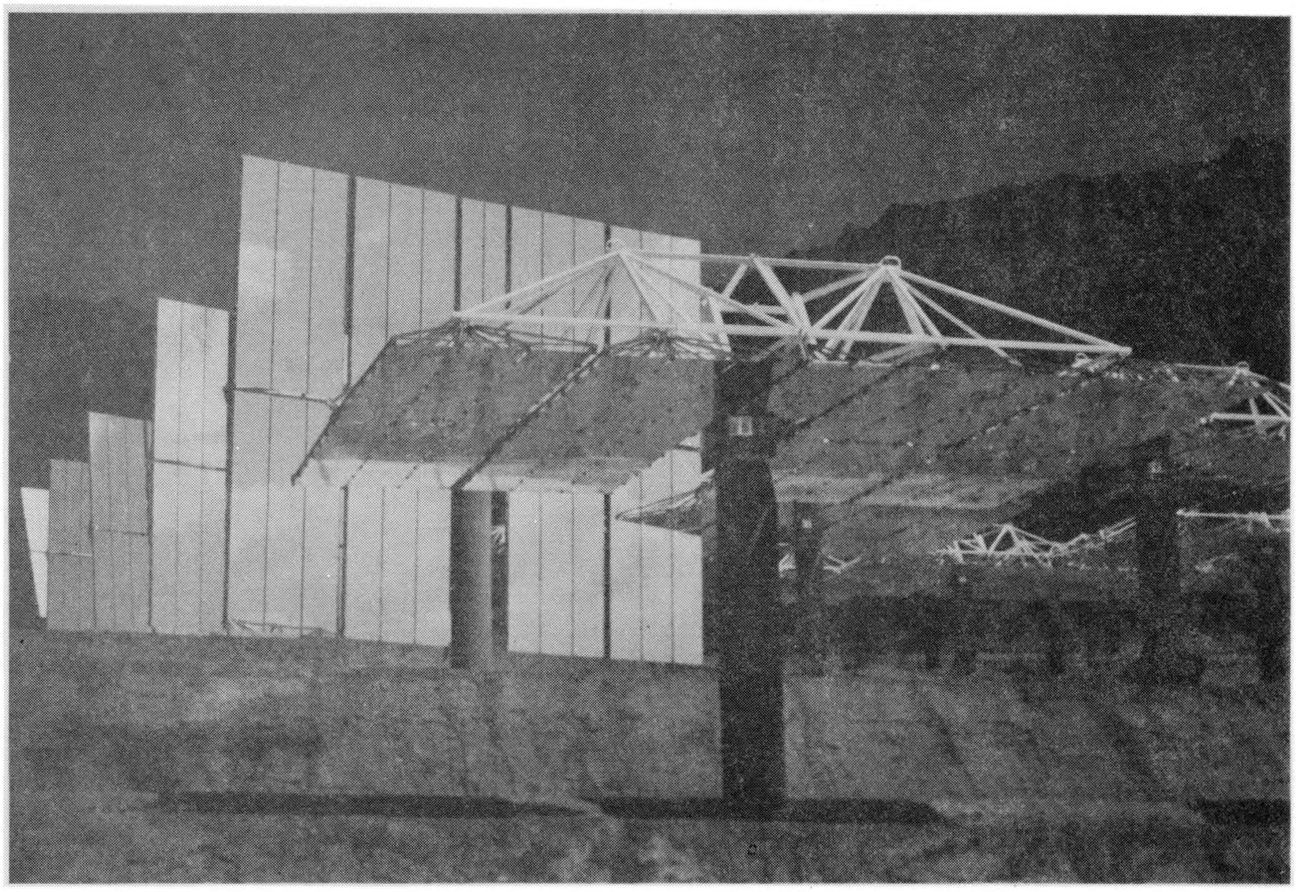


Fig.2 CETHEL heliostats

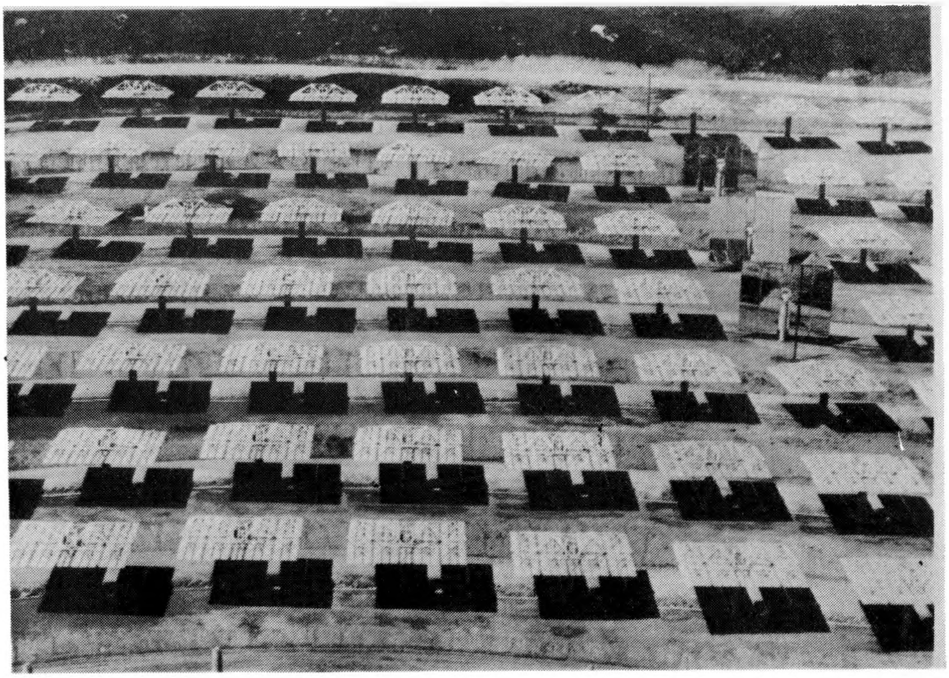


Fig.3 Part of the field of heliostats, seen from the receiver june 1981

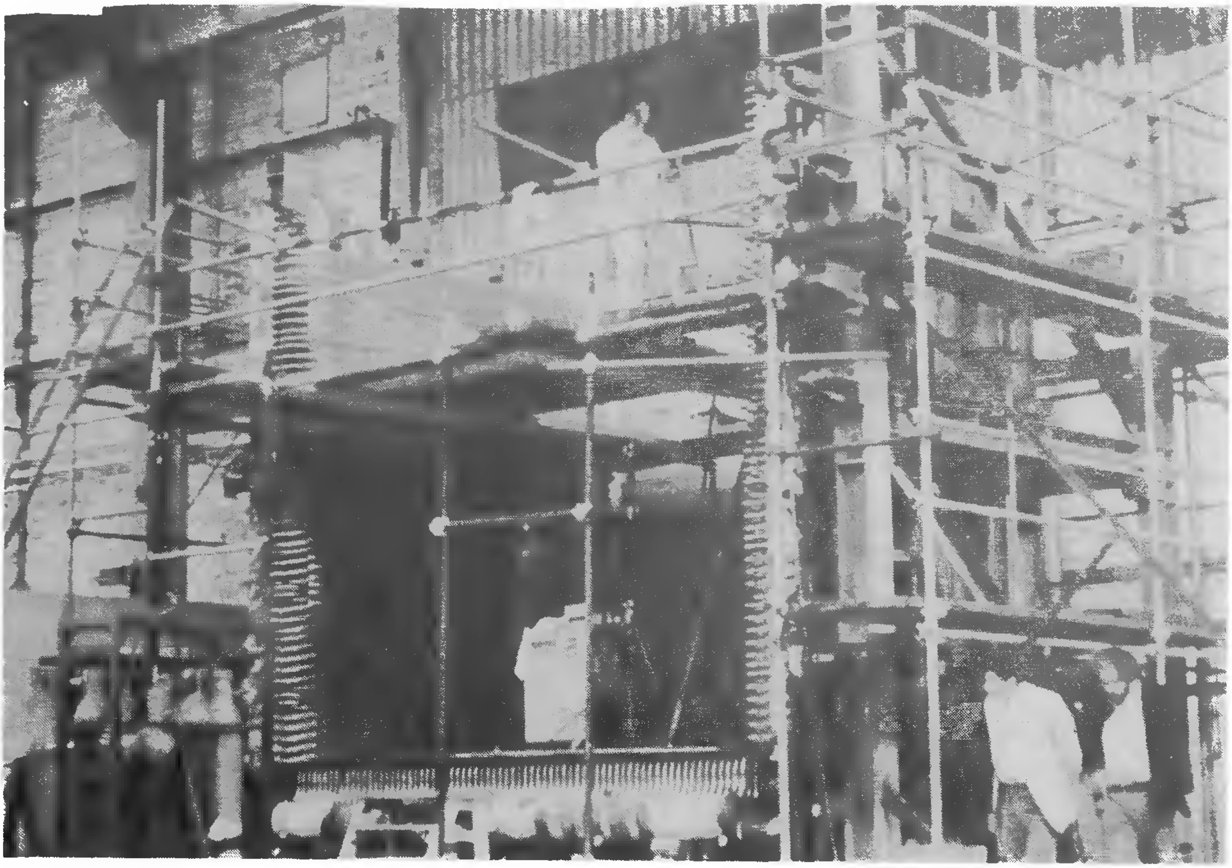


Fig.4 Receiver fabrication by CNIM   may 1981

Receiver Subsystem

The molten salt cavity receiver 4 x 4 x 3.5 m has been built by CNIM in Toulon ship yard. It was delivery on jobsite on june 1981 and lifted up at the top of the tower on september 1981 by using the bridge-crane of the tower.

As the receiver was assembled in Toulon, the successful transport needed exceptional means to cross the Pyrénées mountains.

Storage Subsystem

The two 300 m^3 storage tank have been assembled inside of the EPGS building from april to july 1981. The cold one (250°C) is in A 42, the hot one (450°C) is in 15 CD II 05. They are now being equiped with pressurised water heater.

Molten salt pumps are installed in the tanks. Integrated steam generator is assembled. Hitec salt is stored in sacks on site.

Turbine Generator

The 2.5 MW turbine is installed since august 1981.

The natural dry cooling tower is founded. Alsthom announces 0.28 efficiency, so that the overall efficiency from sun to electricity to the grid reaches 0.20.

Parabolic Dishes

Eleven parabolic dishes have been erected from june to september. They will produce gilotherm at 320°C to provide hot water (250°C, 50 bar) for :

- pre-heating Hitec pipes and tanks
- pre-heating water entering the steam generator
- heating construction offices.

Hot gilotherm will be used to melt salt.

The 80 m^3 thermocline tank is erected in the plant building.

Control Building

The control building, now completed, is a masonry construction inside the general EPGS building ; the control room is open to the south by large windows. Electrical devices, batteries, transformers, are installed on the first floor of the control building.

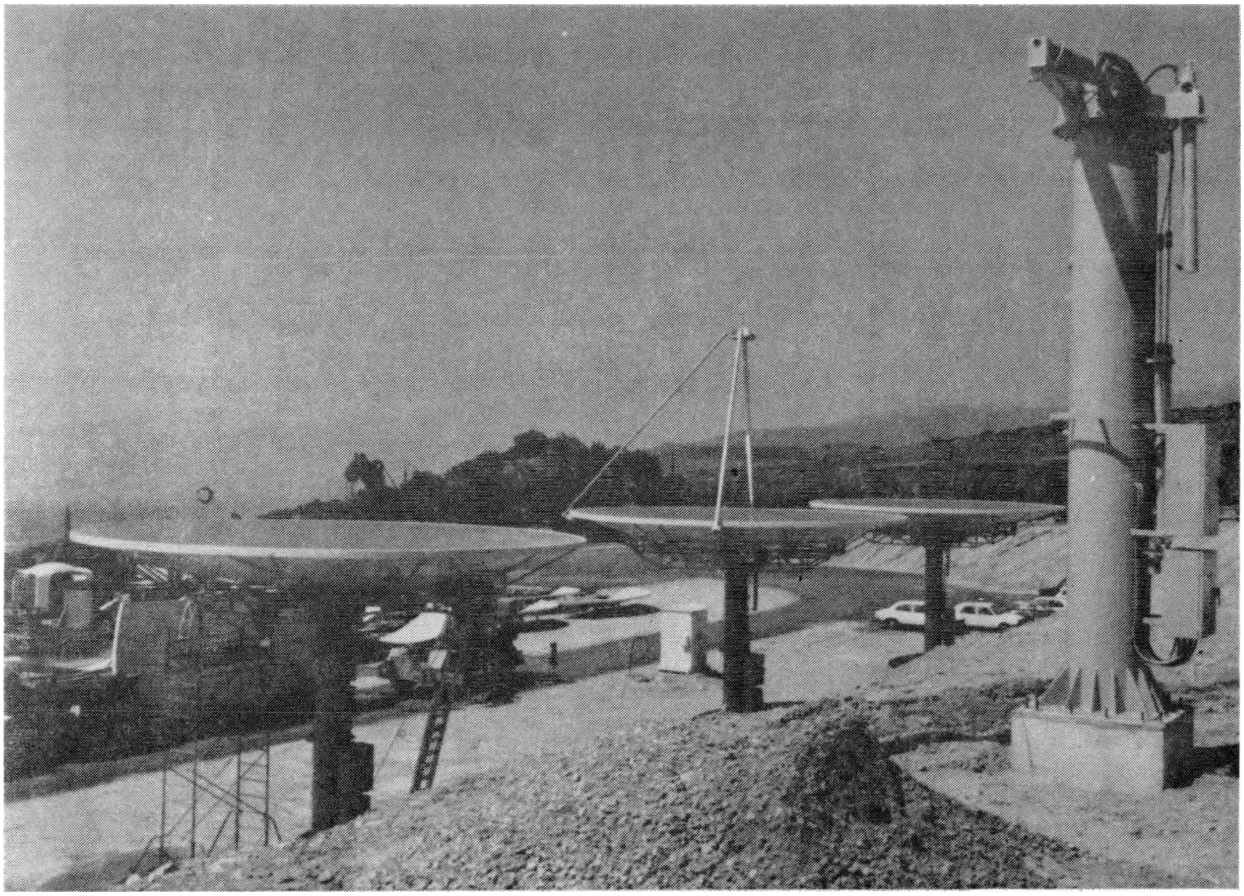


Fig.5 SICOPA parabolic dishes july 1981

Plans For Next Twelve Months

Completion Of Construction

The overall project schedule milestones are shown below :

Government selects partners	june 1979
Start earthwork	October 1979
Start civil construction	april 1980
Start mechanical equipment	april 1981
Complete heliostat field	july 1981
Complete construction	january 1982
Connexion to the grid	april 1982

The receiver, the air cooling tower and the molten salt, water and steam pipes will be completed on december 1981.

The master control system and data acquisition multiplexed subsystem will be operational in january 1982.

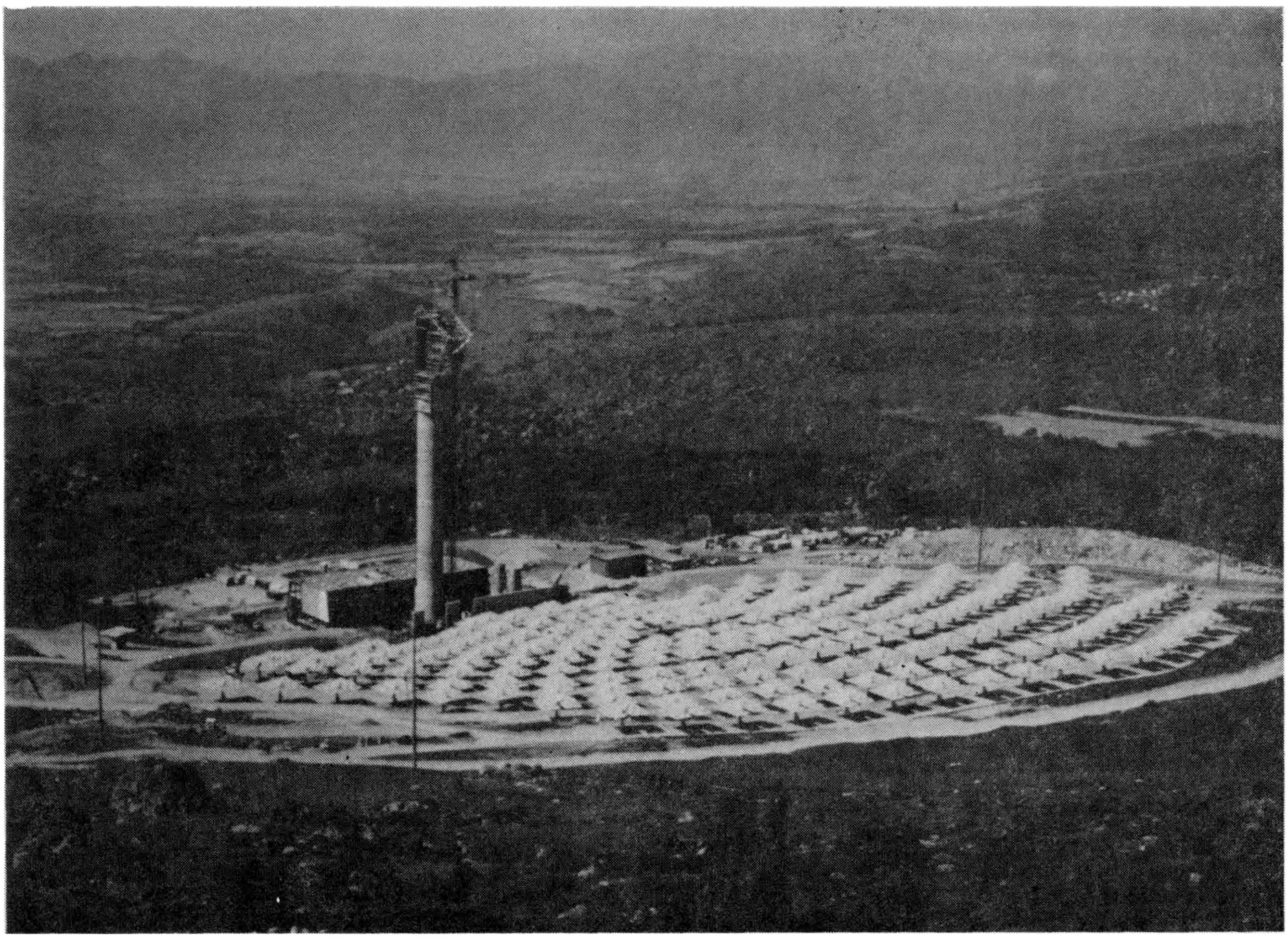


Fig.6 THEMIS general view july 1981

Preliminary Tests

Tests of heliostats have begun on october 1981 and will last till november. These acceptance tests consist of beam characterisation of each heliostat using a 7 x 7 m target equiped with 1024 solar cells.

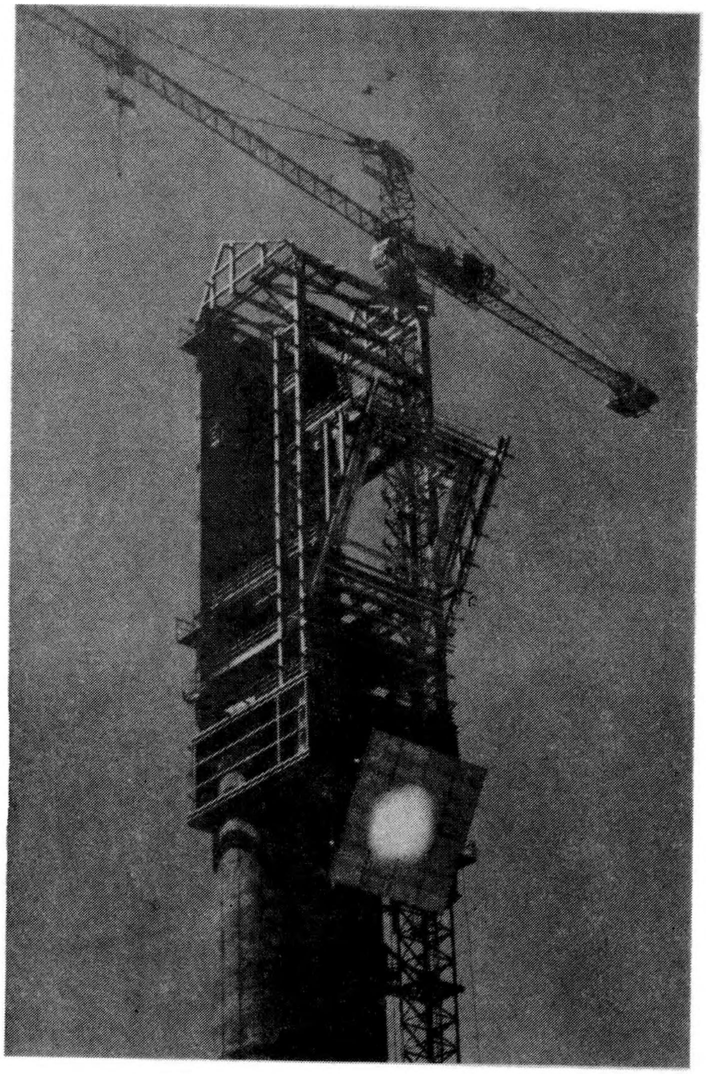


Fig.7 Heliostat test june 1981

Auxiliary devices (water supply, fire protection, compressed air, nitrogen, ...) will be operational in january 1982.

The melting of Hitec salt will be operated on february and march (540 tons).

The tests of the receiver will take place in march. Steam-to-turbine initial operation is scheduled for april with connexion to the grid.

Acceptance Tests

Acceptance tests for receiver subsystem, steam generator, turbine generator unit and main auxiliary devices will be done from may to october 1982.

Experimentation

In july 1982, master control system will be improved by the installation of a colorgraphic terminal and an operational computer to control the plant and provide data acquisition.

A first test phase of two years will begin in summer 1982.

Summary

The 2.5 MW THEMIS central receiver plant is under construction at Targasonne. The operation date has been modified to take into account four months of inclemency during winter 1980-1981. First operation on the grid is now scheduled for april 1982. Main subsystems are completed (heliostat field, turbine generator unit, storage tanks, ...) or in progress and construction will be completed by december 1981. Tests have begun on heliostats and will go on with thermal and electrical equipment in the beginning of 1982.

500 KW CENTRAL RECEIVER SYSTEM (CRS) OF THE SMALL SOLAR POWER SYSTEMS PROJECT (SSPS) ALMERIA

MANFRED BECKER AND WILFRIED GRASSE
DFVLR, COLOGNE, FED. REP. OF GERMANY
IEA OPERATING AGENT

Introduction

The Small Solar Power Systems Project (SSPS), performed under the auspices of the International Energy Agency (IEA), consists of the design, construction, testing, and operation of two dissimilar types of solar thermal power plants. Both have the same electrical output of 500 KW on design point equinox noon ; they deliver the electric energy into the spanish grid or optionally operate in a stand-alone mode. Further details and state of the art descriptions have been reported at the last meetings of this kind, e.g. Refs. 1 and 2.

Objectives

The design requirements were derived from the intention to evaluate and compare the technical, operational, and economical aspects of the two types of facilities. The principal objective is to demonstrate and examine the viability and flexibility of using solar radiation in a thermal cycle for the production of electrical energy. In addition, the sodium technology for solar thermal use, the scale-up capability of such plants, and the minimization of plant costs are essential objectives.

Schedule

On behalf of the nine Participating Countries, DFVLR as Operating Agent conducted and continues the project under supervision of the IEA-SSPS Executive Committee in the following steps:

o	April to September 1977	Specifications, Trade-Offs, Feasibility Considerations
o	October 1977 to September 1978	Plant Design
o	October 1978 to June 1978	Preparation, Optimization
o	July 1979 to August 1981	Procurement, Installation, Functional Testing
o	September to December 1981	Plant Operation by Spanish Utility and Optimization
o	January 1982 to December 1983	Routine Operation by Spanish Utility, Testing and Evaluation

Costs

The nine member countries contribute with different shares to the project. The CRS-part contains the following details:

o	Total System (Interatom) except Heliostat Field and Data Acquisition System	26 MDM
o	Heliostat Field (Martin Marietta C.) with CASA-Part (5.4 MDM) and US-In-Kind Contribution (2 MDM)	7.4 MDM
o	Data Acquisition System (SAIT)	1 MDM
o	Part of Infrastructure	2.7 MDM
o	Heliostat Field Summer Studies (MMC/MDAC)	0.5 MDM
	Total Installation Costs	37.9 MDM

The maximum authorized expenditures are 38.1 MDM. For the test and operation period (Jan. 1, 1982 to Dec. 31, 1983) an allocation of 11 MDM is foreseen by the nine participating countries for the central receiver and the distributed collector systems together.

Overview

The SSPS-CRS power plant in Almeria has been completed and the functional tests have been performed up to the third quarter of 1981. The plant optimization phase will last to the end of the year. Figure 1 is an aereal view of the heliostat field, tower with receiver on top, the machine hall beside the tower, and the office building in the foreground. In Table 1 the major events

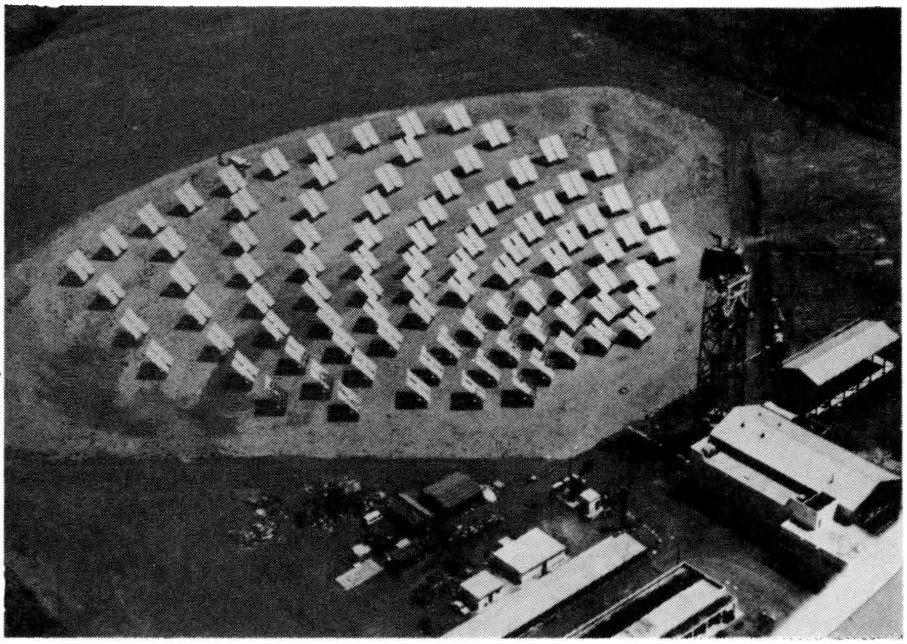


Fig. 1

Aerial View of SSPS - CRS Heliostat Field, Tower with Receiver, and Maschine Hall

TABLE 1

IEA - SSPS	Major Events (CRS)
Dec. 20, 1980	Receiver Mounting on Tower Completed
Jan. 8, 1981	Start of Heliostat Mounting
Febr. 23	First Sodium Filling
April 2	Heliostat Field Installation Completed
9	Data Acquisition System Acceptance
13 to 15	Heliostat Field Acceptance Tests
May 14	Final Heliostat Field Acceptance
30	Total Heliostat Field on Receiver and Start of Solar Tests
June 3	Completion of Testing without Solar Energy and Preliminary Hardware Acceptance
5	Project Status Review by US-DOE (G. Braun)
July 9	Acceptance of DFVLR Heat Flux Distribution Measurement Equipment
20	Operational Readiness of EIR Flux Analyzing System
27	Spilling Steam Engine Operation in No-Load Mode
Aug. 28	Revision of Heliostat Control Boxes Completed
Sept. 20	Power Delivery into Spanish Grid
21	Facility Inauguration

and activities are listed for the period from November 1980 to October 1981. Furthermore, for design conditions at equinox noon the latest power stair step is given in Table 2. The insolation is assumed at 920 W/m^2 and the heliostat field is based on 93 heliostats with a total reflective surface of 3655 m^2. The stair step numbers are based on a mirror reflectivity of 0.911 as official value. The solar multiple is defined as ratio of thermal power produced over immediately used at design conditions, not accounting for the long term storage losses but rather giving a momentary quantity.

TABLE 2

Stair Step at Design Conditions

(Status of July 1981)

Equinox Noon
Insolation 0.92 KW/m^2, Receiver Input 2.84 MW
93 Heliostats with 3655 m^2 Total Reflective Surface

Power	KW	single efficiency	overall efficiency
Insolation	3362		
		0.950	
Ideal Reflection	3194		0.950
		0.911	
Real Reflection	2910		0.865
		0.976	
Receiver Input	2840		0.845
		0.883	
Thermal Input	2508		0.746
Storage	249		
Solar Multiple	1,11		
Heat Exchanger Input	2259		
		0.975	
Steam Input	2203		0.727
		0.281	
Shaft Output	619		0.204
		0.967	
Gross Electric	599		0.198
		0.835	
Net Electric	500		0.165

Heliostat Field

The heliostat field was completed on April 2, 1981. The formal acceptance tests took place from April 13 to 15; the final acceptance was stated on May 14.
Beforehand, the performances of four characteristic heliostats were calculated by Sandia (Ref. 3). Within the acceptance tests slides were taken from every heliostat image and later on evaluated at DFVLR by a beam characterization method similar to that of CRTF in Albuquerque. In Table 3 some essential data are compiled. Apparently, the actual beams were better adjusted and pointed than earlier calculated.

TABLE 3

Single Heliostat Performance Data

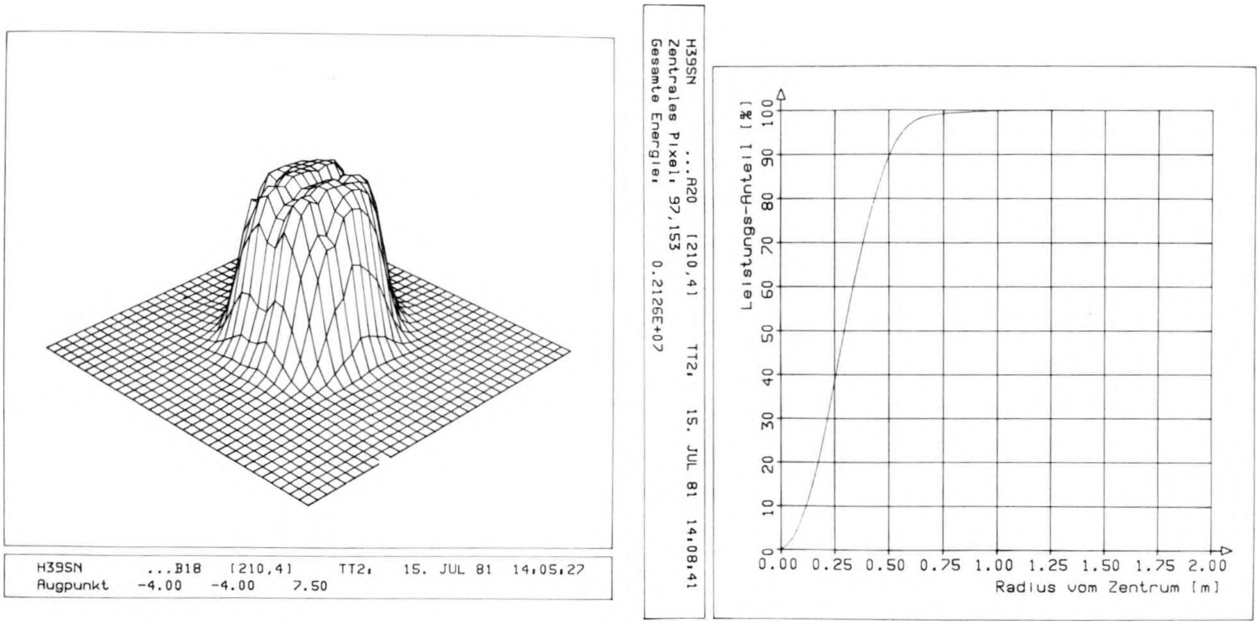
Hel. No.		:	5	39	73	100	
Zone		:	I	II	III	IV	
Row		:	2	6	9	12	
$\dot{q}_{max}$	KW	:	52	26.5	20.5	14.5	A
$d_{90\%\ power}$	m	:	0.78	1.90	2.05	2.65	A
$d_{max.\ slope}$	m	:		0.95	1.20	1.45	B

A Helios calculation for IEA curvature by Sandia, Albuquerque

B BCS determination from slide intensities by DFVLR, Stuttgart

Therefore in the following, some heliostats were biased and focused to other aiming points apart from the aperture center. Concerning the interpretation of the slides, difficulties from intensity distortions have to be stated. As consequence, the 90% power contour was not used for reference. Instead, a determination by maximum slope method was taken from boundary layer definition. Figure 2 gives as example the 3D plot (a) for heliostat No. 39 in row 6 and the power distribution (b) over the distance from the center of the intensity image. Here the deviation between the 90% contour and the maximum slope determination is negligible. The cleft in the middle of the intensity

distribution was caused by the cross wire on the outside recei-
ver doors, which were used as target.



(a) (b)

Fig. 2

Determination of Flux Distribution for Heliostat
No. 39 from Slide Intensities with DFVLR Beam
Characterization System

(a) 3 D Plot

(b) Power Distribution

During the summer months the heliostat field was used as often as possible, both for tracking the standby position and for solar receiver tests. Communication problems occured frequently, as heliostat field controller failures, power losses or error messages. A revision of the heliostat control boxes with reset of timing, enlargement of capacitors and rerouting of encoder return wire finally solved the problems. After Aug. 28, no more serious failures of this sort were reported.
In June and July two heat flux measurement systems were arranged near the aperture plane, the Heat Flux Distribution measurement device (HFD) of DFVLR and the Flux Analyzing System (FAS) of EIR. The HFD uses radiometers mounted in a traversing bar. The accuracy of the system ranges at + 5%. More information will be given at the Heat Flux Measurement Workshops in Albuquerque (Ref. 4). The FAS is a diffuse reflection method similar to the CRTF beam characterization system. The accuracy of this system is estimated at ± 5 to 10%. A detailed report is scheduled for the above mentioned workshop (Ref. 5).

Figure 3 displays in a qualitative way the incoming flux distribution from 93 heliostats on August 12, 1981 measured by FAS in the target plane.

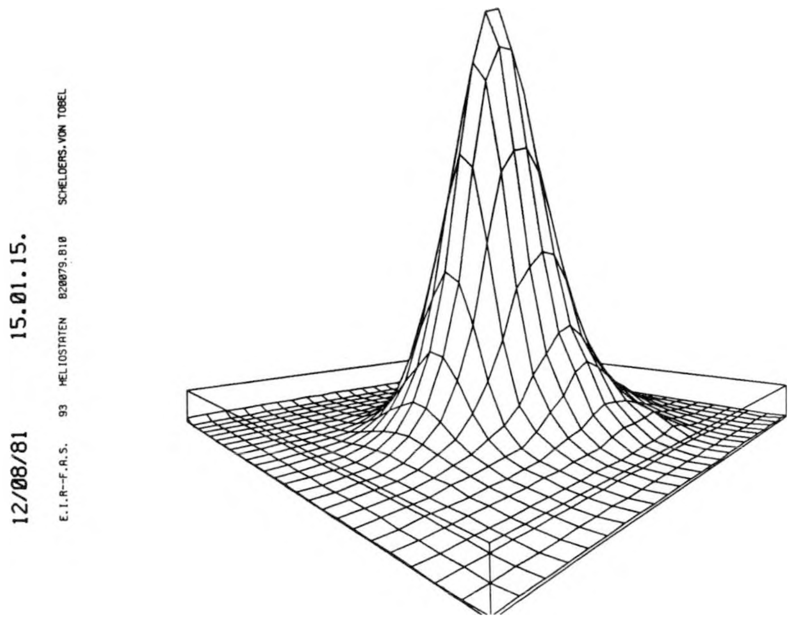


Fig. 3

Flux Distribution in Measurement Plane Produced from all 93 Heliostats and Recorded by BCS-Type Flux Analyzing System (FAS)

First representatively selected results of both systems are plotted in Figure 4. Here the theoretical power input is determined from elements of the HELIOS program. This concerns cosine losses, shading and blocking, reflectivity, losses from atmospheric attenuation and incomplete tracking including aperture intercept. It was also accounted for times of year and day, for actual insolation and heliostat availability. Concerning the evaluation of measurements, data were used from the two flux measuring techniques and from thermal power gain in the receiver sodium tubing. The latter data were divided by the calculated receiver efficiencies for the corresponding part-load conditions.

As official reflectivity value 0.911 was taken over from SANDIA. During our investigations in Almeria the high degree of dependence on updated reflectivity information (averaged over the whole field) was recognized.

Apart from this effect, only the validity of assumptions or requirements for the various loss mechanisms can cause in Figure 4 a distinction between the calculated values and the reality. For the experimental verification,the inaccuracy of the measuring instruments adds up to the margin of uncertainty. Only with some restriction the deviation from the 45 degree line can serve as a performance fulfillment criterion.

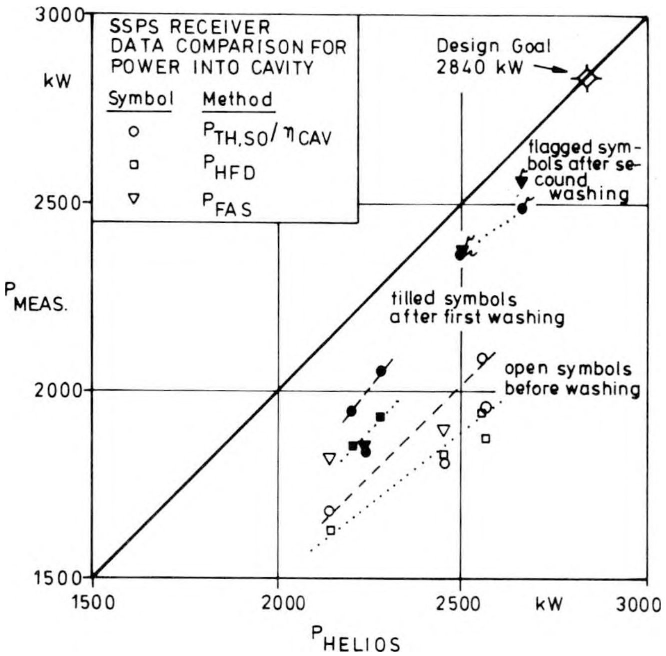


Fig. 4

Measured Powers into SSPS Receiver over Helios-Calculated Values Accounting for Acutal Conditions of Time, Insolation, and Heliostat Availability

P_{THSO}/η_{CAV}	: Sodium Thermal Power/Cavity Efficiency
HFD	: DFVLR - Heat Flux Distribution
FAS	: EIR - Flux Analyzing System

It turned out that the state of mirror cleanliness is the most important issue. While the original data before heliostat washing were for approximately 20% to 25% off from the 45^{o} line, this condition improved after the first heliostat field washing action to 10 to 15%. A second washing finally resulted in a minus 5% deviation.

During the months of July to September two reflectivity measurement activities were performed at Almeria. Reflectometers from SANDIA (R. Stromberg) and F. H. WEDEL (G. Lensch) were at hand. Their results indicated systematically various reflectivity values for different field locations and maximum values after hand washing and soft paper polishing being substantially below the official value of 0.911. A final correction for all possible influences including averaging over the whole field resulted in 0.862 for the US data at Sept. 18, 1981. This refers to the highest power data given in Fig. 4 in the top right. Accounting for the differences between the official reflectivity value and actual reflectances due to the state of contamination, the last measurement results seem to indicate the possibility of reaching the design goal within a few percents.

From all data, taken over a longer period, it was preliminary concluded that the reflectivity loss rate is in the order of 2% per week. If no rainfall can be used as cleaning action, the heliostat field has to be washed quite frequently.

Receiver

The Sulzer/Interatom receiver was mounted on the tower platform at the end of December 1980. In the middle of January 1981, the program on functional tests without solar energy was started. Since April 1981, tests at elevated temperatures were performed, followed by solar tests beginning on May 30. All tests with the receiver and the whole sodium heat transfer cycle demonstrated the qualification for solar application.

Figure 5 shows the assembled receiver tubing with inlet header at bottom left and outlet header at top left. The fourth of six parallel tubes was equipped with temperature measuring thermocouples at each of the six turns on the left side.

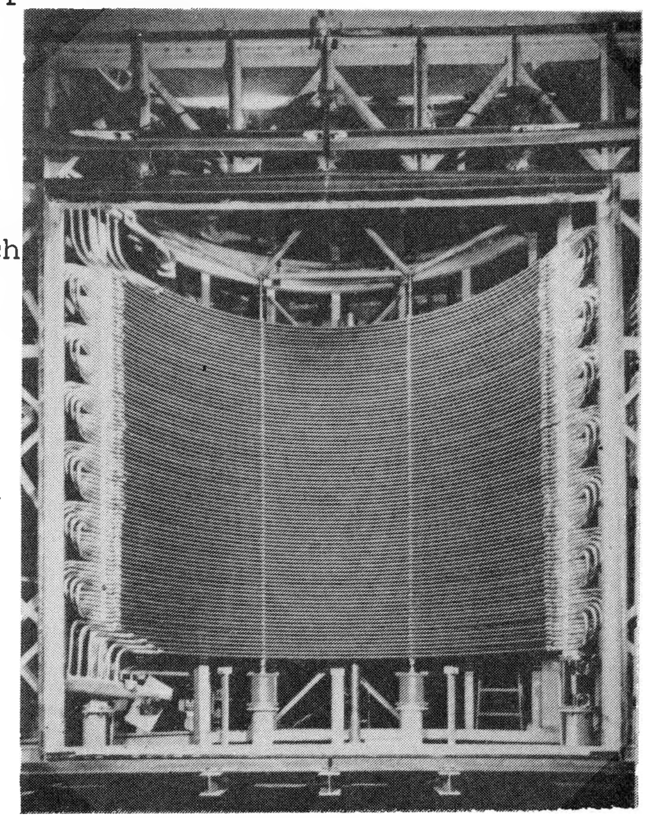


Fig. 5

Sulzer Work Photo of Assembled Receiver Tubing (6 Parallel Tubes) with Inlet Header at Bottom Left and Outlet Header at Top Left.

In Figure 6, the calculated temperature distribution is compared with the thermocouple results from acceptance testing on July 14 and 21. Though a slightly downstream delayed heating-up zone can be observed, general agreement can be stated.

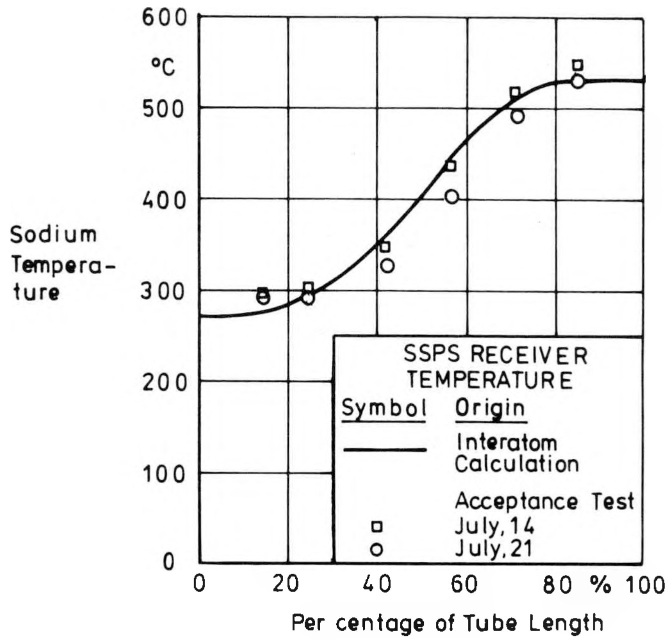


Fig. 6

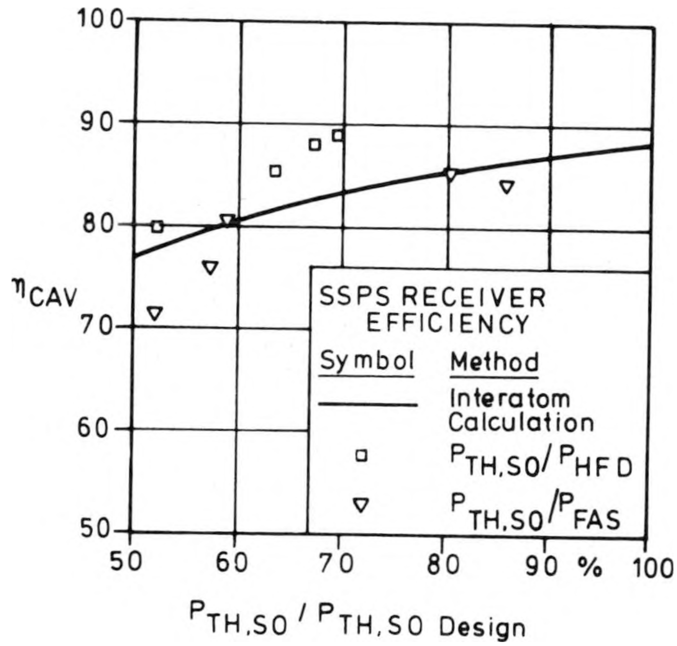
Sodium Temperature Distribution Along the Serpentine Tubing in the Cavity Receiver

The determination of cavity receiver efficiency is attempted in Figure 7. The ratio of thermal sodium power gain towards HFD-measured power input ranges higher than the calculated curve. Efficiency results from the FAS nearly hint into the opposite direction. A considerable amount of additional tests has to be performed to substantiate or change the calculated efficiencies over the load factor. Quite naturally of highest interest will be the region near the design condition at 100%. In principle, these results are of importance for proper determination of convective losses.

The steam generator which transfers the energy from the primary sodium cycle to the secondary steam cycle is finally shown in Figure 8. This is a Sulzer work photo with a view on the steam generator tube during the insertion procedure into its jackets.

Fig. 7

Measured Receiver Cavity Efficiency Towards the Percentage of Thermal Power into Sodium System in Relation to Design Value (2508 KW)



$P_{TH,SO}$: Sodium Thermal Power

HFD : DFVLR - Heat Flux Distribution

FAS : EIR - Flux Analyzing System

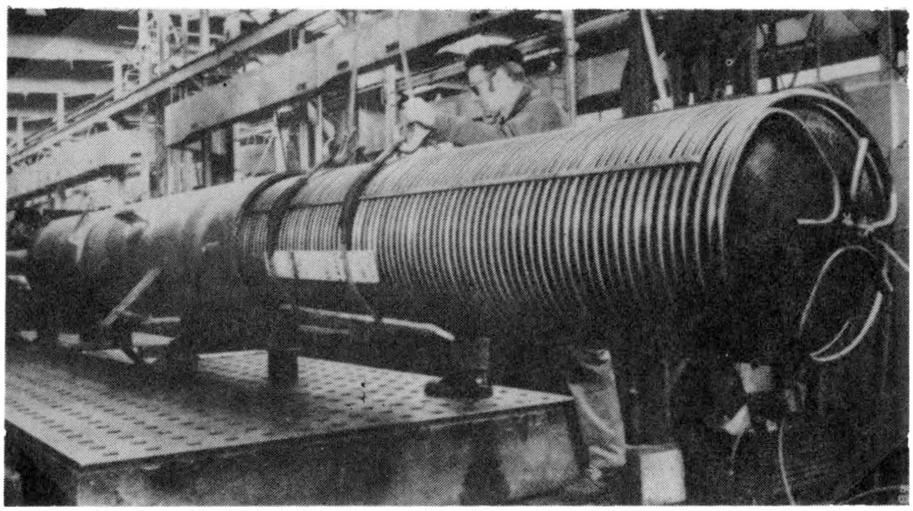


Fig. 8

View of Steam Generator Tube During Insertion into its Jacket
(Sulzer Work Photo)

Technical Planning for Next Year

After the acceptance of the plant, an optimization phase is intended to bridge the gap to routine operation, starting in January 1982. The activities of this program shall enable the plant authorities to operate the power station in a safe and efficient way. The following definitions describe the general categories of a matrix for the "Plant Optimization Phase (POP)":

Objectives:

- Achievement of Basic Plant Knowledge
- Adjustment of Set Points
- Improvements of Conditions, Modes, Strategies

Fields:

- Plant Operation and Performance
- Safety
- Maintenance

Subsystems:

- Energy Collection
- Heat Transfer (including Storage)
- Power Conversion (including Steam Generator)
- Control and Data Acquisition

The "Test and Operation Phase (TOP)" for the two years 1982 and 1983 will be executed due to the agreement between the Contracting Parties. The basic test and operation program describes the following elements:

- System Performance Assessment
- System Control Assessment
- Maintenance Requirements
- Operational Strategies
- Operating Cost Assessment
- Meteorological Measurements
- Advanced Receiver

The detailed technical specifications and requirements for both phases will be set forth in special and detailed plans.

Literature

1 M. Becker, W. Grasse, A. Kalt
500 kW Central Receiver System ...
Semi-Annual Meeting on Solar Central Receiver Systems
Albuquerque, March 1980, Proceedings pp. 48-60

2. W. Grasse
500 kW Central Receiver System ...
Semi-Annual Meeting on Solar Central Receiver Systems
San Francisco, October 1980, Proceedings pp.65-72

3 D.L. King
Evaluation of Production of IEA Mirror Performance...
Sandia-Memo, April 16, 1981

4 M. Becker, F. Diessner, J. Baete
Heat Flux Distribution Measurement Device for the SSPS-CRS Project in Almeria
STTFUA Workshop, Oct. 26-27, 1981, Albuquerque

5 M. Real
A New System for Measuring Highly Concentrated Solar Power
STTFUA Workshop, Oct. 26-27, 1981, Albuquerque

SOLAR REPOWERING PROGRAM

Robert W. Hughey, DOE-SAN

The Repowering Program has been considered to be the final link in the Solar Central Receiver Program between the primarily-Government-funded effort, which has been carried on from 1973 to date, and the ultimate goal of privately-funded commercial enterprise.

The objectives of the Repowering Program are to:

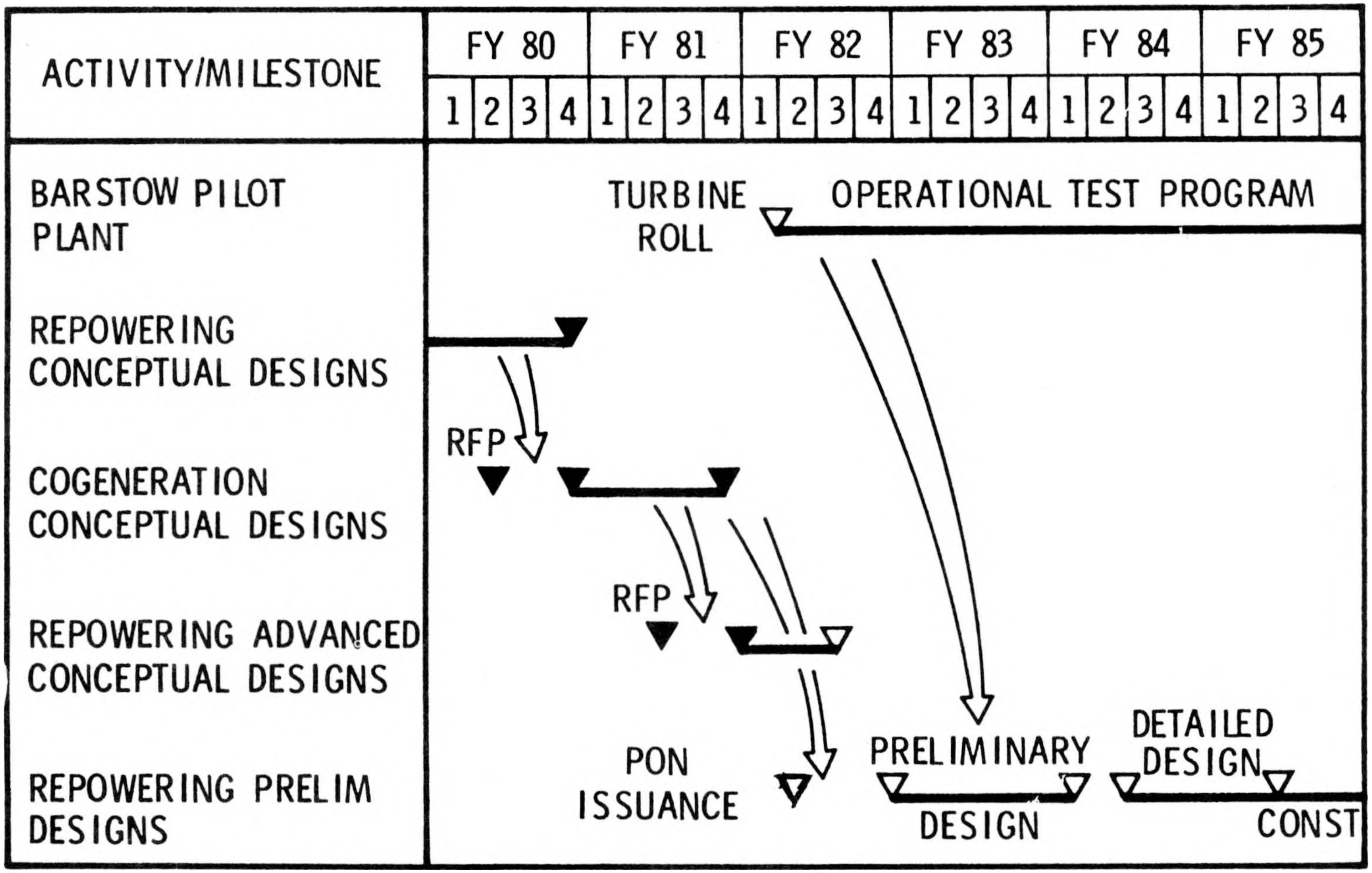
- o Establish economic requirements and performance characteristics of Repowering applications.
- o Refine conceptual designs by utilizing recent developments in Central Receiver (CR) technology.
- o Transfer CR technology from its R&D Phase into first phase of systems application.
- o Determine future R&D requirements through site specific design studies.
- o Define final steps for CR technology transfer to private sector.

The current strategy to accomplish the above objectives is to:

- o Solicit and fund broadly based site-specific conceptual designs and economic analyses.
- o Translate user interest and data developed from conceptual designs into technology demonstration projects.
- o Maintain an innovative R&D program with Barstow and other test facilities.

The overall Schedule for Central Receiver Program shows the relationship between the various Repowering and Cogeneration design studies and how they have fed data into subsequent program developments. Similarly, data and experience gained during the design, construction, and check-out of the Barstow 10 MWe Pilot Plant will provide data for the preliminary and final design phases of Repowering projects. Flowing through the entire Central Receiver Program, and providing vital information to the design work for the Barstow Plant and the Repowering/Cogeneration projects, has been the

Overall Schedule for Central Receiver Program



Technology Development effort sponsored by the Sandia National Laboratories Livermore.

The charts included herein summarize the 13 Repowering Conceptual Design studies completed in FY80 for both electric power and industrial process heat applications. The next chart shows the five Repowering Advanced Conceptual Design (ACD) studies which are currently underway.

A capsule version of what has been learned to data through the Repowering design studies is as follows:

- o A wide spectrum of system design options and applications has been developed.
- o User requirements have been determined and incorporated into development activities.
- o Barstow operation is a requisite for utility and industry committment.
- o Users want simple, reliable solar systems which will not overwhelm normal plant operation.
- o Inadequate rate of return on investment is the major impediment to near-term implementation.
- o The best use of development funds would be to transfer Solar Repowering technology to the utility/industry world.

The principal FY81 accomplishments in the Repowering Program were:

o Repowering Conceptual Design Final Reports published	Oct 80
o Initiated 7 Cogeneration Conceptual Design contracts	Nov 80
o Cogeneration Final Reports published	Sept 81
o RFP issued for Advanced Conceptual Designs	Apr 81
o Five ACD Contracts awarded	Sept 81

FY82 planned activities include:

- o Complete Advanced Conceptual Design studies
- o Issue Program Opportunity Notice for Repowering Preliminary Design of Demonstration Plant*
- o Award contracts for Repowering Preliminary Design of Demonstration Plant*
- o Continue Advanced Development of 2nd Generation Components

REPOWERING PROGRAM

SUMMARY OF SOLAR REPOWERING CONCEPTUAL DESIGNS COMPLETED IN FY80
(Electric Generation)

Utility/System Design	Solar Power Output (MWe)	No. Of Heliostats	Receiver Type	Receiver Temp ($^{\circ}$F)	Storage (hr)
1. Arizona Public Service/Martin Marietta	111	10,300	Cavity-Salt	1050	4
2. El Paso Electric/Westinghouse	82	4,600	Ext-Water	1000	0.3
3. Public Serv. of Oklahoma/Black & Veatch	30	2,200	Ext-Water	1000	0
4. Sierra Pacific Power (NV)/McDonnell Douglas	77	9,400	Ext-Water	1050	6
5. Southwestern Public Service (TX)/Gen. Electric	57	4,700	Ext-Sodium	1100	0.2
6. Texas Electric Service/Rockwell	50	5,300	Ext-Sodium	1100	1
7. West Texas Utilities/Rockwell	60	7,700	Ext-Sodium	1100	4

REPOWERING PROGRAM

SUMMARY OF SOLAR RETROFIT CONCEPTUAL DESIGNS COMPLETED IN FY80
(Industrial Process Heat)

User	Application	Solar Power Output (MWt)	No. of Heliostats	Receiver Type	Receiver Temp (°F)
1. ARCO	Natural Gas Refinery (CA)	12	340	Ext-Oil	560
2. Exxon	Enhanced Oil Recovery (CA)	29	800	Cavity-Water	570
3. Gulf R&D	Ore Processing (NM)	14	430	Ext-Water	400
4. Provident Energy[1]	Oil Refinery (AZ)	44	1,300	Ext-Water	520
5. U. S. Gypsum	Gypsum Board Drying (TX)	11	410	Cavity-Air	1,340
6. Valley Nitrogen	Ammonia Production (CA)	34	1,160	Cavity-Gas	1,450

[1] Buffer storage; all others had zero storage

REPOWERING PROGRAM

ADVANCED CONCEPTUAL DESIGN AWARDS

PRIME/SUB	APPLICATION	SITE	TECHNOLOGY	SIZE HELIOSTATS	SIZE MW_T
O ARIZONA PUBLIC SERVICE/MMC	UTILITY	SAGUARO, AZ.	MOLTEN SALT	8,680	316
O MDAC/SIERRA PACIFIC	UTILITY	FT.CHURCHILL, NEV.	MOLTEN SALT	8,410	330
O BECHTEL/AMFAC SUGAR	COGENERATION	MAUI, HI.	WATER-STEAM	815	26
O ROCKWELL/WEST TEXAS UTILITY	UTILITY	ABILENE, TX.	LIQUID SODIUM	7,880	226
O EL PASO ELECTRIC/ WESTINGHOUSE/ STONE & WEBSTER	UTILITY	EL PASO, TX.	WATER-STEAM	3,700	105

- o Assess third party financing for Repowering projects.

  *Contingent upon funding availability

Current planning (contingent upon FY82 funding availability) calls for the issuance of a Program Opportunity Notice for competitive preliminary designs for a Repowering project. The objectives of this PON would be to:

- o Solicit proposals for Preliminary Design studies for Utility Repowering.
- o Stimulate involvement by utilities in Repowering through a Cooperative Agreement to cost share the Preliminary Design studies.
- o Assess the economic feasibility to proceed with detailed design and construction of a Repowering project by 1986.

Guidance from the House Science and Technology Committee as to the nature and content of this PON are as follows:

- o Application - generation of electric power
- o Cost sharing to significant extent
- o FY82 DOE funding level - $4-$6M
- o Deliverables to include:

  Engineering Design Drawings
  Detailed Construction Cost Estimate
  Prelim. Plant Operations Plan
  Environmental Impact Assessment
  20 Year Term Economic Evaluation

SOLAR CENTRAL RECEIVER

COGENERATION PROGRAM

Keith A. Rose
DOE/San Francisco Operations Office

Historically the production of electricity and industrial process heat to industrial energy demands was provided primarily by cogeneration systems. This was the case previous to the 1920's because a substantial proportion of industrial plants were located away from then existing utility power grids. In the early 1900's about 50% of the total power produced by on-site industrial power plants was provided by cogeneration. by 1950 on-site cogenerated energy decreased to 15%, and by 1974 it decreased to 5%. The main factor contributing to this decline was the availability of less expensive and more reliable electricity from utilities.

The main advantage of cogeneration over separate generation of electricity and process heat is the increase in thermodynamic efficiency. For example, production of 600 KWeh and 10 MBtu separately requires 3.1 barrels of oil (5.8 MBtu/Barrel) but production of the same amount of energy in an cogeneration plant requires only 2.4 barrels of oil. Due to this better thermodynamic efficiency less fuel is burned to produced the same amount of energy and therefore less combustion by-products are produced which pollute the atmosphere.

Cogenerated energy by means of a Solar Central Receiver System is especially attractive in cases where additional peak to intermediate loading capacity is required at an existing industrial facility which is near its maximum pollution control levels. Retrofitting an existing cogeneration facility with a Solar CR system adds additional energy capacity with no additional atmospheric pollution.

The objectives of the Solar CR Cogeneration Program were to:

a. Stimulate the demand (market) for CR technology by adding cogeneration applications to the completed repowering and retrofit conceptual design studies and increasing the number of potential users.

b. Stimulate the supply for CR technology by broadening the base of potential manufacturers of CR technology.

c. Add to the existing technology base novel concepts of coupling solar energy to existing site-specific cogeneration facilities.

Seven projects (See Fig. 1) were selected to participate in this program. DOE/SAN office managed these projects with Sandia National Labs Livermore as technical monitor and Aerospace Corporation as technical advisor. Contracts were awarded in Oct. 1980, the midterms held from February to April 1981, and all projects completed by Sept. 1981. Total DOE funding for these seven studies was $3.1M.

PRIME/SUB	APPLICATION	SITE	TECHNOLOGY	RECEIVER OUTPUT MW_T	NO. OF HELIOS
O GE/TEXASGULF	SULFUR MINING	FORT STOCKTON, TX.	WATER/STEAM	25	865
O BECHTEL/AMFAC	SUGAR CANE PROCESSING	MAUI, HAWAII	WATER/STEAM	29	1050
O GIBBS & HILL/ PHELPS-DODGE	COPPER SMELT- ING	PLAYAS, N.M.	AIR	214	7740
O EXXON/MMC	ENHANCED OIL RECOVERY	BAKERSFIELD, CA.	MOLTEN SALT	109	3020
O B&V/CENTRAL TELE.	PROCESSING NATURAL GAS	LIBERAL, KS.	WATER/STEAM	72	2300
O WESTINGHOUSE/ USAF	SPACE CONDI- TIONING	ROBINS AFB, GA.	WATER/STEAM	7	151
O MDAC/US ARMY	SPACE CONDI- TIONING	FT.HOOD, TX.	MOLTEN SALT	10	266

Figure 1. Cogeneration Program

I will give an overview of four of the seven projects and the remaining three will be presented by the prime contractor for each of the three.

I. The GE/Texas Gulf conceptual design proposes to add on to an existing natural gas fired plant to provide about 20% of the current process heat demand and 100% of the electrical demand required for a sulfur mining operation. The concept specifies 588 2nd generation heliostats in a north field configuration. The receiver is an external natural circulation saturated water/steam receiver producing steam at 521^{o}F and 820 psia. Saturated steam from the receiver is then superheated by a natural gas superheater before injection into an extraction steam turbine. Steam extracted from the turbine is passed through a high pressure heat exchanger to produce superheated hot water to liquefy underground sulfur deposits. The solar receiver is in parallel with a natural gas boiler capable of providing all of the saturated steam demands when solar energy is not available. The system also has a steam accumulator capable of holding a five minute supply of saturated steam in order to smooth solar transients during operation in the solar hybrid mode. At the design point (950 W/m^2) the solar facility will produce 3.0 MWe and 21.6 MWt which equals 20.8% of the total annual energy requirements of the existing facility.

II. The Exxon conceptual design specifies that the solar facility operate in series with two fossil fired boilers. The fossil boilers provide the baseload supply of steam for injection into oil wells for enhanced oil recovery. When solar energy is available, additional steam is available to produce up to 20.4 MWe (100% electrical demand) and 15.8 MWt (60% process thermal demand). The design utilizes 3295 second generation heliostats in a northfield configuration. The receiver is a two-cavity, forced circulation, molten salt receiver with a thermal output of 122 MWt (at design point) at 1050^{o}F and 363 psia. Molten salt is stored in two tanks, a cold tank at 550^{o}F and hot tank at 1050^{o}F. Molten salt from the hot tank is either fed to the process steam generator for injection into a oil well or to the turbine steam generator for production of electricity. On an annual basis the solar facility provides 50% of the total energy required and will save 140,000 barrels of crude oil (5.8M Btu/bbl). Thermal storage is provided in the form of molten salt accumulated in the hot storage tank (1050^{o}F) with a capacity of 380 MWth which is sized to provide steam to the process 24 hours/day and the steam turbine 14 hours/day during the summer months.

III. The Westinghouse conceptual design specifies that the solar facility operates in parallel with existing fossil boilers to satisfy steam demand for space heating, absorption cooling, hot water generation, and provide electricity to Robins Air Force Base in Georgia. The concept utilizes 251 second generation heliostats focusing sunlight on to an external natural-recirculation water/steam receiver with preheater, boiler, and superheater elements.

At design point the receiver output is 8.8 MWt at 770°F and 890 psia. The solar facility contribution to the existing power plant at design point is 700 KWe (7% total peak demand) and 7.9 MWt (55% total peak demand). On an annual basis the solar facility provides 35% of the total power plant requirements. A commercial high-back-pressure turbine would be installed as part of the solar facility and integrated into the existing distribution net work. To achieve best thermodynamic cycle efficiency and to best utilize available solar energy, this solar system configuration is a topping cycle. Superheated steam first passes through a turbine and the exhaust steam is fed into the steam header of the existing power plant. The configuration is such that the turbine can be bypassed when sufficient solar insolation is not available to produce steam temperature and pressure suitable for the turbine. This mode of operation allows use of the solar facility on partially cloudy days without ramping of the turbine or requiring a thermal storage system as a buffer.

IV. The Gibbs & Hill/Phelps Dodge conceptual design proposes that a Solar CR system provides solar heated air to an existing flash furnace and a convective superheater at a copper smelting facility. The additional heat provided by the solar facility relative to the existing source provides for a 90 percent increase in copper production. A north biased surrounding field of 10,441 second generation heliostats focuses sunlight on four apertures of a forced-circulation cavity receiver. The receiver produces 270 MWt (at design point) of hot air at 1500°F and 58 psia which is fed directly into an array of open cycle gas turbines. A novel method of speed control of the gas turbines modulates air mass flow rate in the turbines to accommodate changes in absorbed power at the receiver while maintaining the constant turbine exhaust temperature required for the process heat application. The exhaust air is then gated to the process or the thermal energy storage system (TES). The TES consists of 160 M^3 of copper slag as the storage medium capable of supplying 96 hours of flash furnace operation (4089 MWth). At the design point the solar facility will produce 46 MWe and 54 MWt delivered to the process. The solar fraction on an annual basis is 0.8 with a potential fuel saving of 436,000 barrels of crude oil.

The economics of all the solar cogeneration projects was found to be strongly dependent on several variables including heliostat costs, fuel costs, fuel escalation rates, plant life, operation and maintenance costs, and federal and state solar tax credits. I have picked examples from the Exxon and GE/Texas Gulf projects to illustrate the effects of some of these variables.

The results of the GE/Texas Gulf study showed that as the price of natural gas varied from \$3/MBtu to \$7/MBtu (1986 cost-1980 \$) the discounted cash rate of return (DCRR) of the solar facility, at a fixed DOE cost sharing of 50%, varied from 2% to 15% respectively. The same study showed that a future commercial solar cogeneration plant purchasing electricity at \$.11/KWh would provide a 11% DCRR for heliostat costs of \$260/M^2 (1980 \$) and a 20% DCRR for heliostats at \$99/M^2. The GE/Texas Gulf study also showed that at a natural gas price of \$7/MBtu the DCRR varied from 10.6% to 20.4% when the total federal tax credit varied from 10% to 50%. (This case assumed an 80% DOE cost share. No tax credit would be given on this 80%.)

The Exxon study showed that as the operation and maintenance cost of the solar facility increased from 1% of the total system capital cost to 3% of the capital cost, the levelized energy cost increased from \$40/HWth to \$60/MWth. The same study showed that a conventional oil fired facility replacing the solar facility would be sensitive to fuel escalation rates. As oil escalates from 8% to 16% per year, levelized energy cost would increase from \$22/MWth to \$63/MWth.

The accomplishments of the Solar CR Cogeneration Program were:

1. Seven new site-specific applications for Solar CR technology were evaluated in terms of performance and economics. The potential market for CR technology was expanded to include cogeneration applications.

2. Novel technical concepts of coupling solar derived energy to an existing cogeneration facility were developed. For example, Gibbs & Hill developed a novel turbine control systems which regulates solar-heated air mass flow rate while maintaining a constant turbine exhaust temperature.

3. Potential users were convinced that Solar CR technology is acceptable but maintained that the economics are not presently attractive without favorable tax, finance, and legislative incentives.

Legislative incentives favorable towards cogeneration include:

1. <u>The Power Plant and Industrial Fuel Use Act</u> which emphasizes the use of coal, synthetic fuels, and renewable alternative energy sources to replace oil and natural gas for electric power plants and major fuel burning installations. Cogenerators receive a permanent exemption from this ban on oil and natural gas.

2. <u>Public Utility Regulatory Policies Act</u> (PURPA) contains provisions requiring electric utilities to either buy from or sell to cogeneration and small power production facilities (under 80 MWe) at prescribed rates which are nondiscriminatory.

3. Federal and State solar tax credits (15% federal and up to 35% state) which provide tax credits for investment in solar facilities. Many of these credits will expire in 1985. Potential users of solar CR technology feel that extention of solar tax credits beyond 1985 are essential to their investment in solar CR technology.

In conclusion, cogeneration has grown increasingly attractive as an alternative to conventional energy systems in all market sectors. The main reason for this renewed interest in cogeneration is the recent sharp increase in the price of fossil fuel energy. Given a favorable economic and regulatory climate, solar cogeneration can play a major role in this growing cogeneration market.

CONCEPTUAL DESIGN OF A SOLAR COGENERATION FACILITY AT PIONEER MILL CO., LTD

Jack R. Darnell
Bechtel Group, Inc.
San Francisco, CA 94119

Introduction

A conceptual design for a solar cogeneration facility has been prepared by a team led by Bechtel Group, Inc. with funding from the U.S. Department of Energy (DOE). As shown in Figure 1, the design involves the addition of a solar central receiver steam supply to the Pioneer Mill Co., Ltd. sugar factory. Implementation of this project would demonstrate a typical industrial application of solar energy to reduce the consumption of imported oil.

Bechtel Group, Inc. was the prime contractor to DOE for the study. Sandia National Laboratories acted as DOE's Technical Manager. Amfac Sugar Company, the site owner/operator, was a major subcontractor. Foster Wheeler Development Corp. and Northrup, Inc. were subcontractors responsible for the design of the solar receiver and the collector system, respectively.

Amfac Sugar Company has been heavily involved in the design effort. Their requirements of simplicity and reliability were important criteria in the selection of water/steam for the system working fluid. As a typical industrial energy consumer, they have also been thoroughly introduced to this solar technology through this involvement.

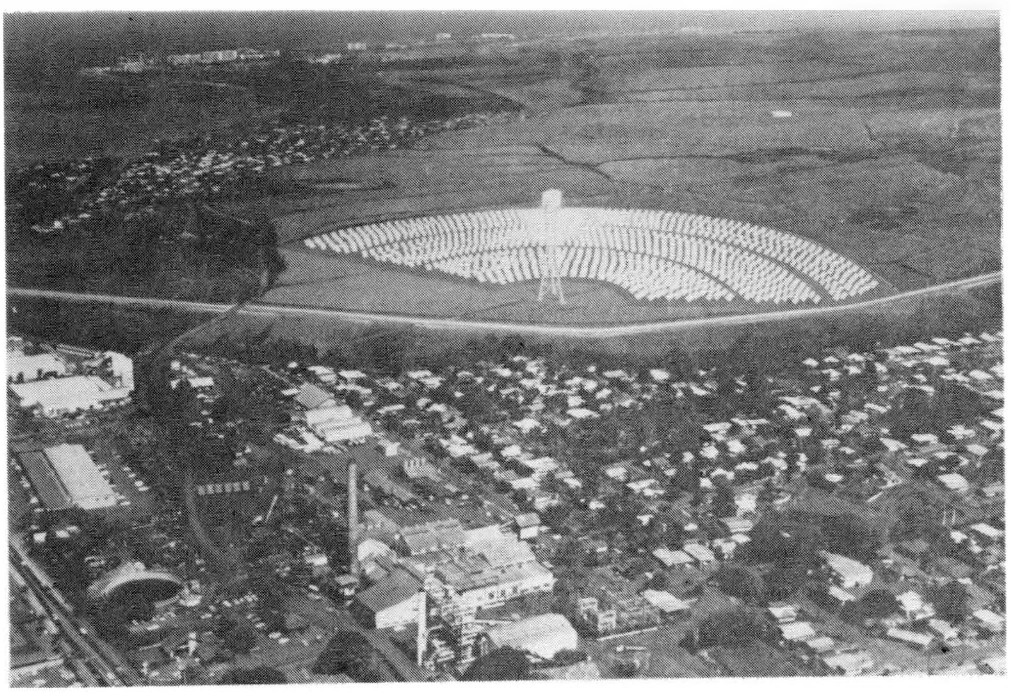


Figure 1 Artist's Concept of Solar Cogeneration Facility

This project provides an excellent opportunity for a joint effort by the government and the industrial sector to demonstrate that such a system can achieve wide commercial success under certain conditions in those areas of the U.S. possessing a significant solar resource.

Site Characteristics

Pioneer Mill is located on the west coast of Maui in the Hawaiian Islands, adjacent to the town of Lahaina, at coordinates 20.8° north and 156.7° west. The plantation at Pioneer Mill, which is owned by Amfac, occupies 35.5 km^2 (8,776 acres)of land. The area has a general west-facing slope, which extends from a populated resort area along the beach to the steep foothill slopes of the West Maui Mountains. The plantation altitude varies between 3 m (10 ft) and 590 m (1,925 ft) above sea level.

The general climatic pattern at the site is tropical and is dominated by the trade winds that blow consistently from the northeast. The area is typically sunny and dry and has relatively light winds. Temperature extremes are 35.5C (96F) and 9C (48F). Annual rainfall averages 34.5 cm (13.6 in), although most occurs during winter storms.

No direct insolation data were available for the Lahaina area at the initiation of this study. An insolation model was developed and calibrated to several sets of total insolation data from Lahaina and the direct insolation data available from the University of Hawaii at Manoa (near Honolulu). This model predicts an average of 6.85 kWh/m^2-day of direct insolation at the site. A site solar data monitoring program was established with Amfac funding in October 1980 and is continuing. The data collected to date corresponds reasonably well to the predictions of the insolation model.

Existing Facility Description

Pioneer Mill Company, Ltd., operates a sugarcane plantation and raw sugar factory. Since 1895, the factory has been processing sugarcane as it is harvested, and producing molasses and raw crystalline sugar. The factory consumes intermediate-pressure steam at 1.82 MPa (265 psia) and 260C (500F) for motive power, low-pressure steam at 205 kPa (30 psia) and 135C (275F) for process heating, and electricity for motors and controls. The major electrical demand on the plantation is for irrigation pumping. Two boilers produce high-pressure steam that is supplied to the main turbine generator at 5.96 MPa (865 psia) and 399C (750F). Two controlled extraction points from the turbine supply steam for the factory. Excess electric power is supplied to the Maui Electric Company grid through the mill substation.

The operations at Pioneer Mill produce a by-product biomass fuel called bagasse, which is the cellulose residue of sugarcane. Bagasse currently provides about 76 percent of the annual energy input to the steam produced. The remainder of the annual energy is supplied by about 9 641 m^3 (60,588 bbl) of No. 6 oil. Bagasse can be stored for a few days, and can therefore be used in place of thermal storage for the solar facility, which was designed to displace the maximum possible oil consumption at Pioneer Mill.

The factory normally operates 40 weeks during the year to coincide with the sugarcane harvest. During this harvest season, typically March through November, the factory operates on a 24 hr/day, 5 day/wk schedule. The nominal operating rate, based on cleaned cane, is 109 000 kg/hr (120 tons/hr), but outages and interruptions reduce this to an average of 92 500 kg/hr (102 tons/hr).

The boilers and turbine generator are operated to meet the needs of the plantation and supply electric power to Maui Electric on demand. During factory operation, each boiler is operated at approximately 40 800 kg/hr (90,000 lb/hr), and the generator produces about 8 MWe. During weekend operation, the factory steam demand is eliminated and the turbine is operated in a condensing mode to match electrical demand, usually between 3 MWe and 6 MWe, and only one boiler is operated. In the 12-week off season, boiler and turbine operation are similar to operation during weekends.

Conceptual Design

Solar repowering for Pioneer Mill consists of adding a collector field, a tower-mounted receiver, and a steam pipeline connecting the receiver with the existing plant and controls, as shown in Figure 2. Approximately 815 heliostats, each with 52.8 m^2 (568 ft^2) reflective area, are arranged in a 150° north field which covers about 0.17 km^2 (42 acres) of land. The twin-cavity, natural-circulatin water-steam receiver is supported upon a 76 m (250 ft) steel tower. The receiver output is 26.2 MWt, supplying about 50 percent of the total main stream energy at the design point.

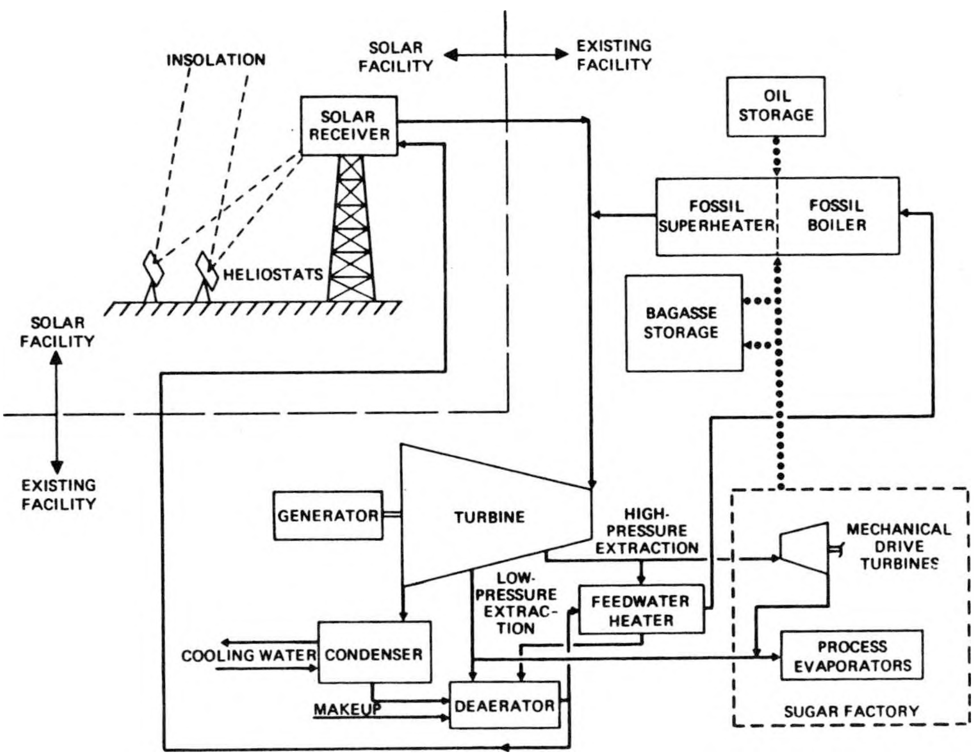


Figure 2 System Flow Diagram

Steam and condensate pipelines, about 1 130 m (3,700 ft) long, connect the receiver with the plant. A steam mixing station to mix steam from the existing boilers with steam from the receiver is located at the mill. An expanded control room and additional bagasse storage capacity are needed to accommodate the retrofit.

The water-steam solar receiver will operate in parallel with the existing boilers. When solar-produced steam is available, bagasse will be diverted from the boiler to the storage house, from which it can be reclaimed when solar steam is not available. This use of bagasse eliminates the need for thermal energy storage and allows the displacement of about 53 percent of all the oil currently consumed during the harvest season. During the 3-month off season, when the factory does not produce bagasse, solar-produced steam will displace a portion of the oil currently burned to meet the year-round irrigation requirements.

Collector System. The function of the collector system is to reflect solar radiation to the receiver. The collector system consists of an optimized layout of 815 ARCO-Northrup second generation heliostats on individual pipe foundations, control and power wiring, and heliostat controls.

Each heliostat has 52.8 m^2 (568 ft^2) of reflective area, composed of 12 second surface silvered glass mirror modules measuring 1.2 m (4 ft) by 3.7 m (12 ft). Each heliostat is mounted on a 0.6 m (2 ft) diameter by 6.7 m (22 ft) long steel pipe which is placed in an augered 3 m (10 ft) deep hole and set in concrete. The site of the collector field is located approximately 670 m (2,200 ft) north of the mill in a sugarcane field.

The heliostat layout is based on a radial stagger pattern to minimize shading and blocking of adjacent heliostats. There are 24 concentric rows of heliostats, the farthest being 360 m (1,180 ft) from the tower. The radial centerline of the collector field points 15° east of north from the tower. This was done to compensate for early morning shadowing by the West Maui mountains, and results in a peak geometric efficiency at approximately one hour after noon.

The collector system provides the heat input to the receiver and is the primary control element for receiver thermal input. At the design point it delivers 30.2 MWt to the aperture planes of the receiver cavities. The heliostats are controlled through a three-level, open loop control system to track the sun and supply the maximum amount of power available to the receiver. The power supplied varies with both the daily and seasonal variation in sun position.

Receiver System. The selected receiver concept is a twin-cavity, natural-circulation steam generator with separate superheat circuitry. Water/steam was chosen as the receiver working fluid because of the simple interface with the existing facility. In addition, the technology is well developed and is available to support the operation of the solar cogeneration facility by 1985.

The configuration of the twin-cavity receiver is shown in Figure 3. The receiver is symmetric with respect to a panel passing through the common wall that partitions the two cavities. Since the selected heliostat field varies slightly from the north of the tower location, the common wall is rotated 15° east from due north. The square aperture of each cavity is 6.52 m (21.4 ft) on a side with its centerline extending at an angle of 37.5° from the common wall.

All boiler and superheater panels are made of tubes that are joined along their length by continuous weld integral fins to form vertical flat Monowalls™. Carbon steel (SA-210 A1) boiler tubes of 50.8 mm (2.0 in) O.D. stainless steel (SA-213 TP316H) tubes for the superheat panels.

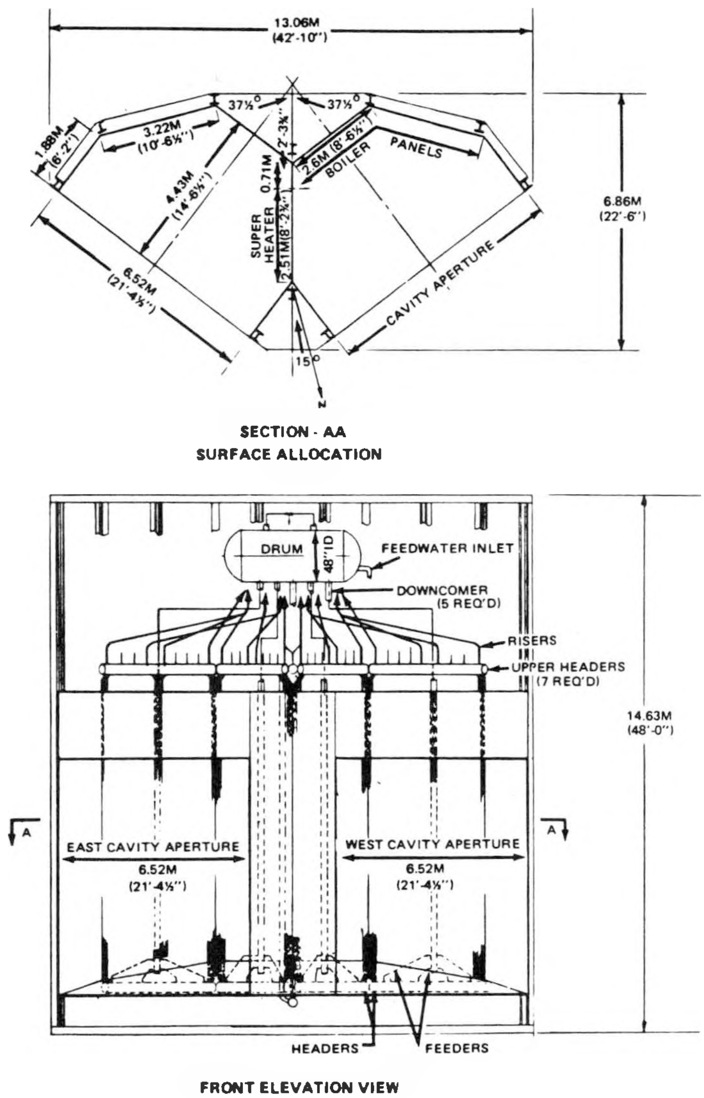


Figure 3 Twin-Cavity Receiver Configuration

The superheater consists of four vertical passes in series. The steam is heated by absorbing incident solar flux from both sides of panels in the successive passes until it reaches its specified outlet temperature. A spray attemperator is used for steam temperature control.

During normal operation, receiver outlet steam pressure is regulated by the steam mixing station located at Pioneer Mill. The startup flow regulator is activated during the startup periods in order to bring up drum pressure at an optimum rate. Feedwater flow is controlled by a conventional three-element feedwater regulator of the type used on fossil-fueled drum-type boilers.

The receiver was sized to produce 33 500 kg/hr (73,900 lb/hr) of superheated steam at a pressure of 6 854 kPa (994 psia) and a temperature of 438C (820F), with a thermal output of 26.2 MWt. For a feedwater temperature of 113C (235F), approximately 18.2 percent of the total thermal output is required to superheat the steam.

The three-sided tower supports the receiver apertures at the 76 m (250 ft) elevation and the tower is fabricated from steel pipe sections.

Thermal Transport System. The thermal transport system provides the physical interface between the existing mill facility and the new solar systems. The thermal transport system includes the steam and condensate pipes between the receiver system and the mill facility, condensate transfer pumps, receiver feed pumps, a condensate holding tank, a warmup loop with heater and circulating pump, a steam mixing station with electric steam superheaters and pressure reducing valves, and a small emergency steam turbine generator.

The condensate transfer pumps are located in the existing mill boiler house. The steam mixing station also is at the mill in a building adjacent to the steam turbine generators. The rest of the thermal transport system equipment is installed in a building at the base of the receiver tower.

The thermal transport steam piping is 15 cm (6 in) in diameter with 11.4 cm (4.5 in) of insulation and is 1 130 m (3,700 ft) long. The condensate pipe is 10 cm (4 in) in diameter with 3.8 cm (1.5 in) of insulation and is 1 190 m (3,900 ft) long. Low alloy steel is used for the steam pipe and carbon steel is used for the condensate pipe.

During startup, the mixing station ensures that the receiver steam is compatable with the mill boiler steam as early as possible and to minimize wasted energy. After an overnight shutdown, the receiver metal and water is heated up by mill steam that is obtained from the thermal transport steam line. While the steam is below the design temperature, four vertical electric steam superheaters, each rated at 400 kWe, are used to top off the temperature of the receiver steam to the same temperature as the mill steam. If the factory is operating, another option is to dump the steam into the intermediate pressure or low pressure extraction headers, or to the main condenser.

Master Control System. The primary function of the master control system is to integrate the operation of the solar facility with the mill and to acquire and store data. The major components and elements of the master control system are contained in an extension to the existing mill control room and in a new solar control room at the base of the receiver tower. The main control point for the operation of the collector and receiver systems is the solar control room. The solar operator has visual feedback of collector field operation and weather through closed circuit TV cameras.

The controls for the mill end of the thermal transport system are located in the expansion of the existing mill control room. The mill operator will have control of the mixing station so that the stability of the mill operation can be maintained. Automatic startup sequences are programmed into the controls but the mill operator can select options such as routing of startup steam from the receiver.

Nonsolar Energy System. The nonsolar energy system includes the modifications to the existing mill facility to accommodate the solar retrofit. New pipe connections at the mill are required for condensate and main steam, and from the mixing station to the intermediate pressure and low pressure process headers and to the condenser. The capacity of the existing bagasse storage building and bagasse handling equipment must also be increased.

System Performance

The solar facility is designed to deliver 25.9 MWt to the main steam line at the turbine inlet at 1 p.m. on the equinox day. With 815 heliostats and 950 W/m^2 insolation, the incident solar power is 40.9 MWt and the individual loss mechanisms are shown on the design point stairstep efficiency diagram, Figure 4. Solar energy provides 50 percent of the energy in the main steam at the design point. The remainder is supplied by the existing boiler burning bagasse during factory operation.

The net outputs are also shown in Figure 4. The largest portion is process heat, delivered from both extraction headers. A small amount of mechnanical power is produced in the factory-equipment-drive turbines. The additional power required by the solar facility (225 kWe) is included in the computation of the net electrical output.

The annual average stairstep efficiency diagram is shown in Figure 5. The average solar input of 6.85 kWh/m^2-day results in 56 530 MWht annually supplied to main steam line. The solar input to the main steam is equivalent to a savings of 5 817 m^3 of oil at 38.6 x 10^6 kJ/m^3 (36,582 bbls at 5.8 x 10^6 Btu/bbl) using a boiler efficiency of 0.905. The actual displacement of No. 6 fuel oil (6.45 x 10^6 Btu/bbl) from the Pioneer Mill boilers is 4 580 m^3 (28,800 bbl). The additional gross electrical generation is 1 696 MWhe, but after accounting for solar auxiliary power, the net added electrical generation is 133 MWhe.

Economic Analysis and Results

The analysis of the economic viability of the solar retrofit at Pioneer Mill was based on typical Amfac criteria and methodology. The two evaluation criteria that were applied are internal rate of return and the investment that Amfac could support while achieving the project-specific hurdle rate. The choice of a 20 percent hurdle rate by Amfac with equity financing represents an investment in a developing technology with which Amfac has no direct experience. The analysis of the after-tax discounted cash flows included the following elements:

- Capital costs distributed over the construction period
- Annual operating and maintenance costs
- Lost revenues from sugar and bagasse displaced by the solar retrofit
- Annual savings in No. 6 fuel oil
- Revenues from Maui Electric Company for additional electric energy sales

The assumptions used for the base case analysis are listed in Table 1. First quarter 1981 dollars were used as the basis for the calculations.

The results for the base case show a calculated IRR of 4.5 percent, well below the required hurdle rate for the project. For the base case, Amfac would consider investing only about 10 percent of the total required investment.

Sensitivity analyses were performed to determine the effect of changes in major parameters on the economic results. An economic scenario incorporating improvements in several of these parameters was then developed and analyzed. The results indicated that for a more mature stage of solar technology development, with higher costs of displaced fuel, higher escalation rates, and a longer project lifetime, this type of system has the potential for meeting Amfac's investment criteria. Other considerations, including the desirability of Hawaii and U.S. energy independence and the possibility of "creative" financing of such a project, were also found to be important in the overall assessment of the project's viability.

Development Plan

A development plan was prepared for the project to define all necessary steps to progress from this conceptual design study to an operating demonstration project. A project schedule was also developed, and the following major milestones were identified:

- Start of preliminary design — January 1982
- Approval for construction — January 1983

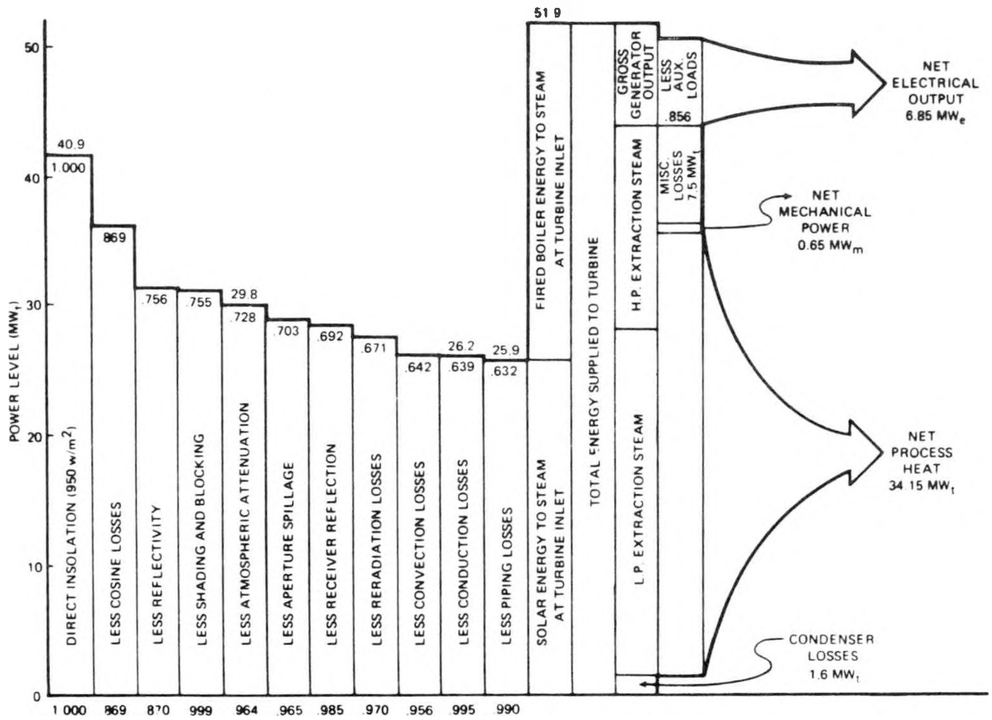


Figure 4 Stairstep Efficiency Diagram-Design Point

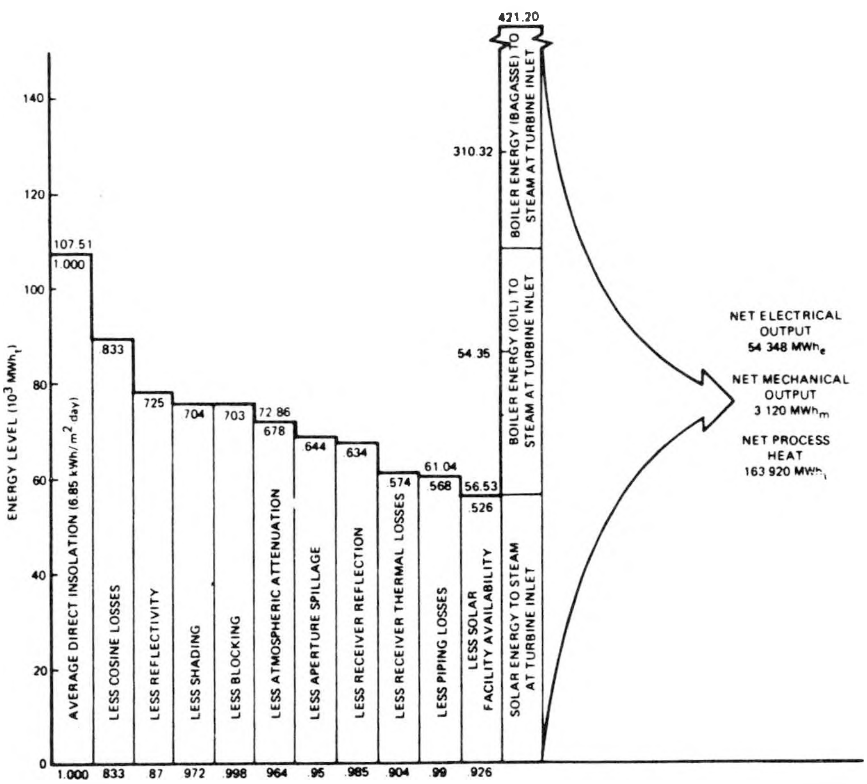


Figure 5 Stairstep Efficiency Diagram-Annual Average

- Start tower foundation — October 1983
- Modification to mill piping — January 1984
- Initial operation — February 1985

Site Owner's Assessment

Amfac's overall project evaluation is positive, especially for an emerging technology. The basic technology is perceived to be sound and worthy of Amfac's continued efforts in attempting to reduce oil cost. The operational simplicity and flexibility of the solar design will allow uninterrupted mill operations despite discontinuities in the solar energy supply.

The economic considerations of the project will almost exclusively determine Amfac's equity participation in the construction of the solar facility. If Amfac's initial risk could be reduced by equity participation tied to actual demonstrated results, then greater Amfac equity participation would potentially be possible. Such creative financing as reimbursible grants tied to future realized savings would allow the government to assume a greater share of the risk for the first projects of this type without assuming a disproportionate share of the total investment. Greater industry participation would be possible under these circumstances.

Table 1

Baseline Assumptions for Economic Analysis

Item	Assumption
Capital cost + owner's cost	$37,000,000
Construction period	3 years
Initial operation date	February, 1986
Operating lifetime	20 years
Annual O&M cost	$406,000
Displaced sugar value	$3,300/acre/yr (42 acres displaced)
Displaced bagasse value	$20,000/yr
Fuel savings	28,800 bbl/yr of No. 6 fuel oil
Additional electricity sales	133 MWhe
Value of electricity	(0.85)x($.066253/kWhe)
General inflation, capital and O&M escalation rates	10 percent
Fuel and bagasse escalation rate	12 percent
Hurdle rate	20 percent
Tax credits	Federal - 25 percent State - 10 percent
Tax rates	Federal - 46 percent State - 10 percent
Depreciation method	Double declining balance
Tax life	14 years

CONCEPTUAL DESIGN OF A SOLAR COGENERATION FACILITY IN SOUTHWESTERN KANSAS

J. E. Harder
Black & Veatch Consulting Engineers
Kansas City, Missouri

Introduction

This paper describes an effort to develop and evaluate a site-specific conceptual design of a solar central receiver system integrated with an existing cogeneration facility. The cogeneration facility studied is the Central Telephone & Utilities — Western Power (CTU-WP) Cimarron River Station located near Liberal, Kansas. The Cimarron River Station generates electricity for the CTU-WP system and delivers a portion of that electricity and process steam to the National Helium Corporation natural gas processing plant, located adjacent to Cimarron River Station.

The project objective was to develop the best site-specific solar conceptual design that would fulfill the following requirements.

- Provide practical and effective use of solar energy.
- Have the potential for construction and operation by 1986.
- Have the potential for wide commercial application and significant fossil fuel savings.
- Make maximum use of existing solar energy technology.

Project tasks included development of a solar conceptual design, identification of the economic value of the solar addition, and preparation of a development plan to implement the design and construction of the facility. Figure 1 is an artist's rendering of the conceptual design.

Important criteria for the technical approach and site selection were the use of proven and accepted technology and a plant whose physical condition, age, and usage are compatible with solar cogeneration.

The technical approach selected was a water/steam solar central receiver supplying superheated steam to the Cimarron River Station turbine. The use of a water/steam receiver permits generation of steam whose pressure and temperature conditions match those currently used in central stations for electric generation, and permits the application of steam generation technology which is mature, reliable, and well-established with potential users. Receiver fluid design criteria are well understood; furthermore, water chemistry and materials compatibility at the operating conditions of the solar receiver are known, and the risks associated with combining materials to perform in uncertain operating regimes are eliminated.

DOE Contract No. DE-AC03-81SF11439. Black & Veatch was supported on the contract by Central Telephone & Utilities — Western Power, Babcock & Wilcox, and the Foxboro Company.

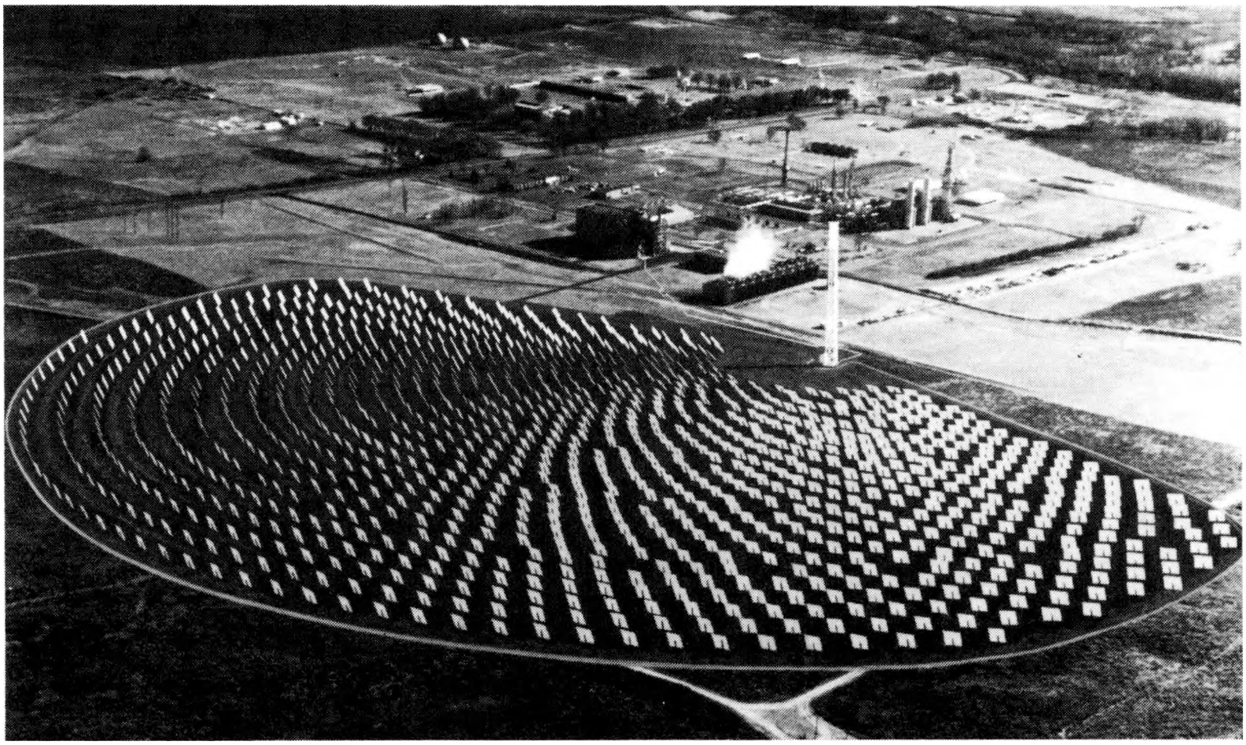


Figure 1. Solar Cogeneration Facility

The selection of Cimarron River Station as a host cogeneration facility for solar augmentation was influenced by two major factors. First, it is representative of a medium size cogeneration facility with a typical industrial processing plant operating on a 24-hour basis with relatively constant electrical and thermal power demands. Second, due to its location and direct mean daily average insolation of approximately 6.1 kWh/m^2, Cimarron River Station is representative of a large group of other potential cogeneration facilities.

Facility Description

The Cimarron River Station is located about 18 kilometers (11 miles) northeast of Liberal, Kansas, as shown on Figure 2. The National Helium Corporation's natural gas processing plant borders the Cimarron River Station on the south. Primary access to the site is provided by US Highway 54. The station is located on the 162,000 m^2 (40 acre) site currently owned by CTU-WP. National Helium Corporation owns additional land to the north, west, and south of the CTU-WP property. Together, the land presently owned by CTU-WP and National Helium Corporation would provide for all the land required for the proposed heliostat field, receiver tower, and receiver piping system.

As shown in Figure 3, the Cimarron River Station cogeneration facility contains three major elements: a natural gas fueled conventional steam power plant (Unit 1), a combustion gas turbine (Unit 2), and a natural gas fueled process steam generator. Unit 1, which became operational in 1963, utilizes a 44 MWe General Electric tandem compound, double flow, non-reheat turbine generator with design steam inlet conditions of 8.72 MPa (1,265 psia) and 510 C (950 F) and overpressure operating conditions of 9.58 MPa (1,390 psia). The turbine generator is normally operated at the overpressure condition for improved cycle efficiency and has a maximum capability of 60 MWe. The Unit 1 steam generator was built by Babcock & Wilcox and is a two drum Stirling, natural circulation, pressurized furnace, with a design rating of 192,740 kg/h (425,000 lb/h), 9.06 MPa (1,315 psia), 513 C (955 F) superheated steam. The maximum extended capability is 226,760 kg/h (500,000 lb/h), 9.99 MPa (1,450 psia), 513 C (955 F). The Unit 1 cycle configuration includes five stages of feedwater heating. The steam cycle also employs a horizontal, two pass, surface type condenser and a mechanical draft wet cooling tower. The plant control systems were supplied by the Foxboro Company.

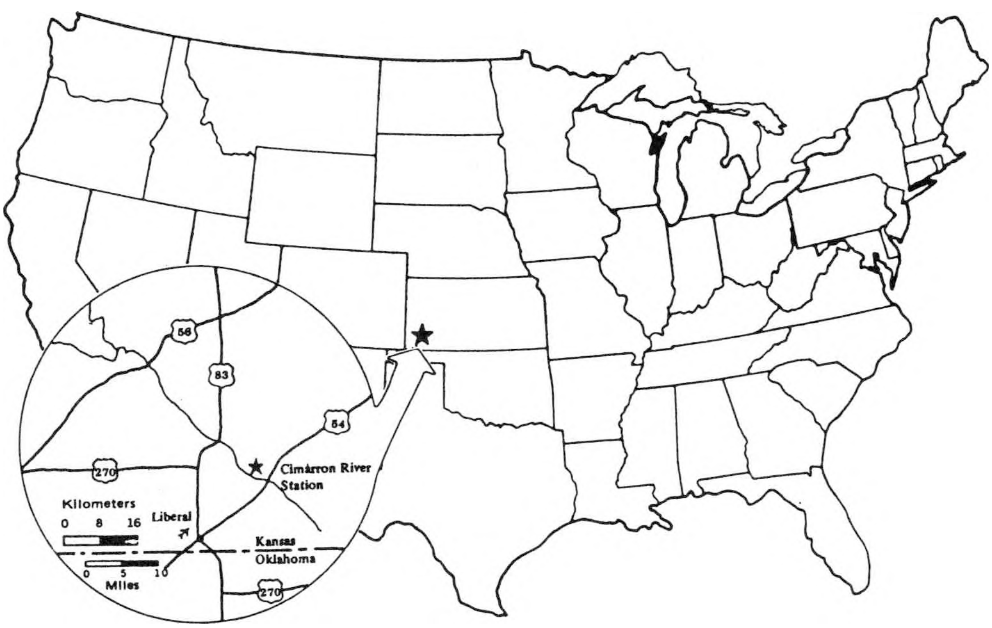


Figure 2. Cimarron River Station Location

The combustion turbine (Unit 2) is rated at 14 MWe. It is provided with an exhaust heat recovery heat exchanger. When Units 1 and 2 are operating in a combined cycle mode, the Unit 1 high pressure feedwater heaters are taken out of service and feedwater heating is provided by the exhaust heat recovery heat exchanger. The combustion turbine is normally only operated during the summer peaking season in a combined cycle mode with Unit 1.

The process steam generator has a design pressure of 1.83 MPa (265 psia) and has a capability of 27,000 kg/h (60,000 lb/h) of steam. This process steam generator is utilized to provide process steam to National Helium Corporation when Unit 1 is shut down.

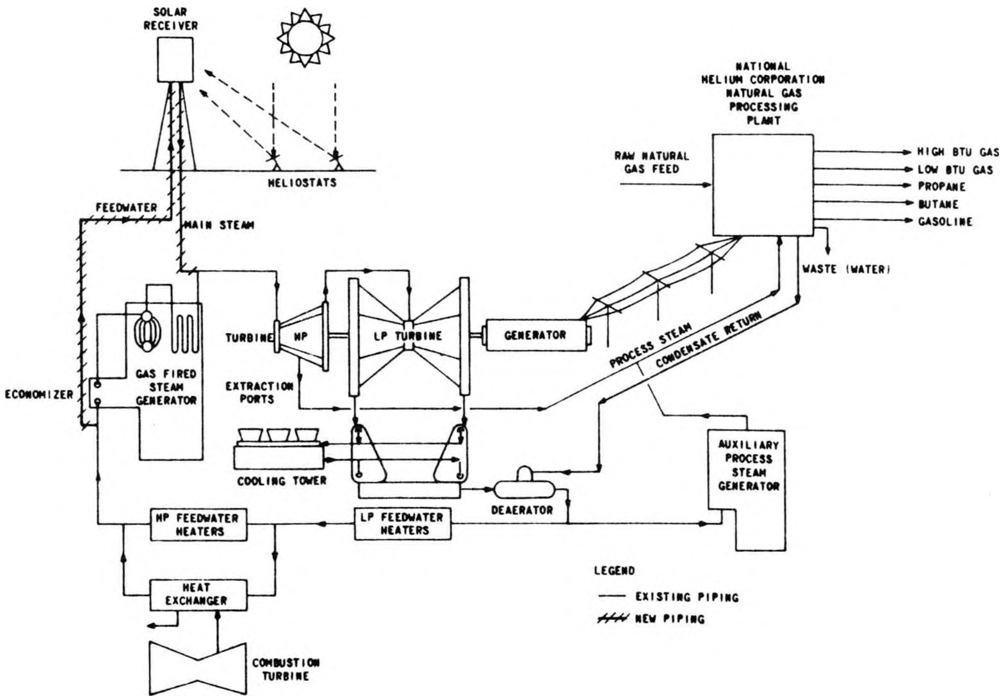


Figure 3. Simplified Schematic of Cogeneration Facility

Service water and makeup water for the circulating water system is provided from five wells located onsite. Cooling tower blowdown is directed to an onsite evaporation pond.

The cogeneration facility provides electricity to the Western Power grid and process steam and electrical energy to the adjacent National Helium Corporation plant. Process steam is taken from the first two extraction ports of the steam turbine through pressure regulating valves to maintain 0.65 MPa (95 psia) steam for delivery to National Helium Corporation. This steam is desuperheated to 204 C (400 F). The electric energy supplied to National Helium Corporation may be provided from either the Cimarron River Station or the Western Power grid. The National Helium Corporation plant processes natural gas for the Detroit, Michigan, area. A refrigeration process is utilized to remove the propane, butane, and gasoline (pentane and greater fractions) products. At the same time, water and carbon dioxide are removed from the gas stream. The refrigeration process used requires both electric and thermal energy in the ratio of approximately 3:1, thermal equivalent.

The solar addition to Unit 1 will take a portion of the feedwater from the discharge of the highest pressure feedwater heater to generate steam in the solar receiver, and will deliver this steam to the turbine through a connection to the existing main steam line. No modifications to the National Helium Corporation plant, Unit 2, or the process steam generator will be required.

Conceptual Design

The solar cogeneration facility is comprised of five major systems: collector system, receiver system, receiver piping system, solar master control system, and solar auxiliary electric system. These five solar systems are fully integrated with the existing fossil energy system.

The solar cogeneration facility operates in a hybrid mode; the steam flows generated by solar and fossil energy are merged before entering the turbine. At the design point of noon, March 21, the solar facility supplies a net power of 37.13 MWt with a reference insolation of 950 W/m^2; this corresponds to a net plant output of 15 MWe electricity and 3.7 MWt process steam. The functional requirements, design and operating characteristics, site requirements, and performance of each system are described below.

The collector system, based on DOE second generation heliostat specifications, consists of 1,057 heliostats [55,780 m^2 (600,103 ft^2)] of reflective area] optimally located on 34 circular arcs centered on and north of the receiver support tower. They occupy an area of 216,000 m^2 (53 acres), which is 848 m (2,782 ft) wide (east-west) and the radius of the outer row of heliostats is 424 m (1,391 ft). As shown in the site arrangement drawing, Figure 4, the heliostats are located in a staggered radial array, which allows close packing with minimum optical interference. Each heliostat has a unique, fixed aim point selected so as to provide uniform flux on the receiver.

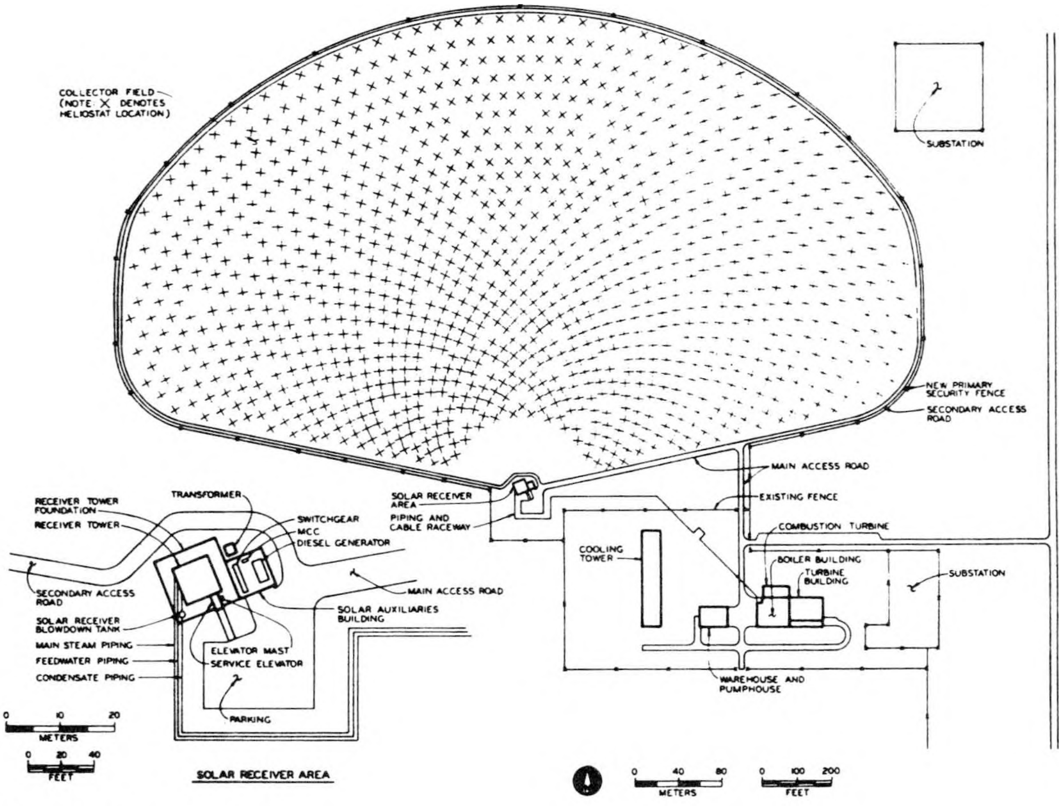


Figure 4. Site Arrangement

The receiver system converts solar energy into steam thermal energy; this system consists of an external receiver and its support tower. The external receiver, shown in Figure 5, offers a simpler design, smaller size, and lighter weight than a cavity receiver; and the efficiency of this external receiver design is only slightly lower than that of a cavity receiver. Pumped circulation was selected to permit the maximum freedom for transitions between operating modes; extensive thermohydraulic analyses of the receiver design show excellent performance under transient conditions. The use of commercial materials and fabrication procedures further assures reliability, low maintenance, and safety. The heat absorbing surface is configured as an eight panel, 210 degree sector of a right circular cylinder centered at 84 m (276 ft) above grade level. The cylinder is 6.71 m (22 ft) in diameter and 9.45 m (31 ft) high, with two concentric heat absorbing surfaces. The inner surface has six panels which comprise the superheater surface; the outer surface forms a protective screen in front of the superheater and comprises the evaporator (boiler) surface; the economizer has two panels, one located at either side of the superheater panel array. The south 150 degree sector of the receiver cylinder, which does not contain heat transfer surfaces, provides the storage region for two 110 degree closure doors, which are used to reduce heat loss during shutdown. Superheater temperature control is accomplished through spray attemperation. The receiver has its own control system which interfaces with the solar master control system.

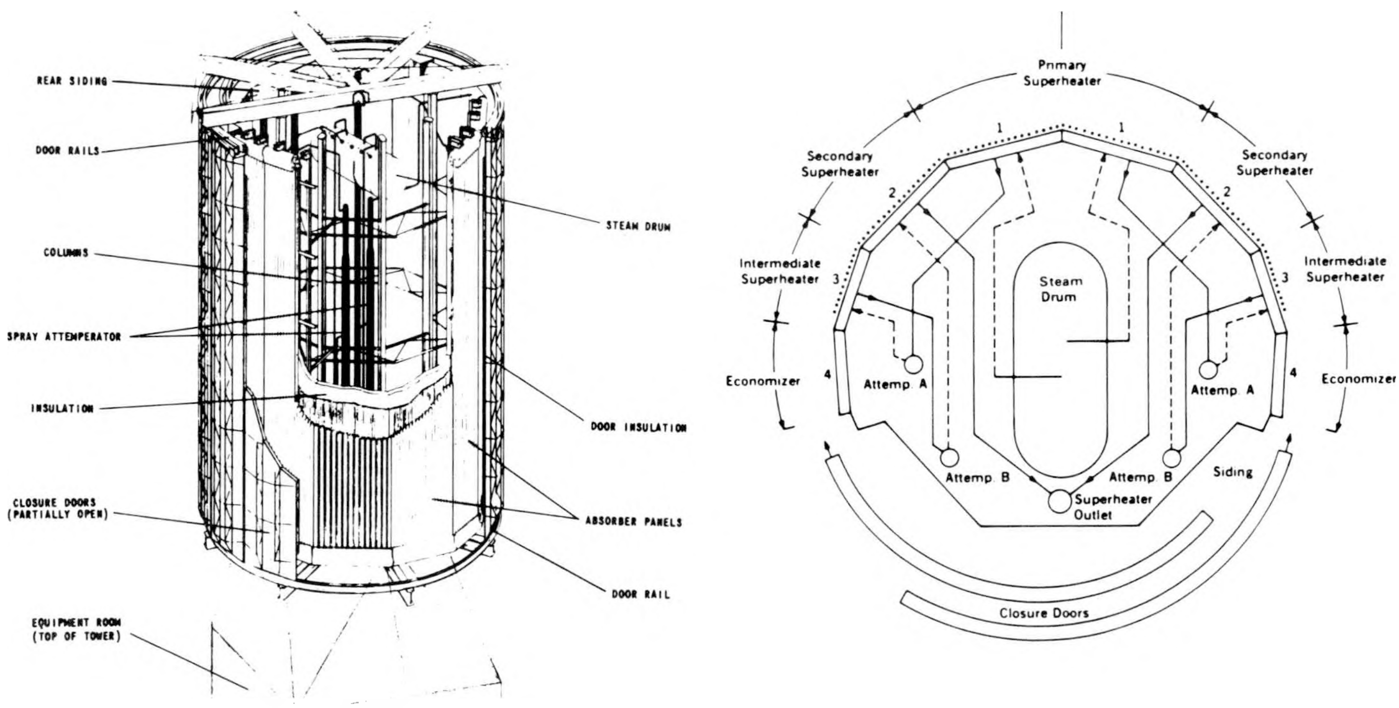


Figure 5. Solar Receiver

The receiver tower is a steel structure, rising 74.4 m (244 ft) above grade, and tapering from 7.32 m (24 ft) in width at the base to 4.27 m (14 ft) in width at the top. The tower will consist of four support legs of bolted structural steel construction, with x-bracing to provide resistance to lateral loads. An equipment room is located in the top section of the tower to house control panels, chemical feed, and other required equipment. Tower accessories include an elevator, aircraft obstruction lighting, caged ladder, and communication and ventilation systems.

The receiver piping system provides the piping interface between the solar receiver and the existing fossil energy system. The system transports feedwater to the receiver from the fossil system, and high energy steam from the receiver to its interface with the fossil system. It also provides blowdown and drain lines for the receiver. The system consists of piping, pumps, tanks, vents, valves, water chemistry equipment, and control elements.

The solar master control system coordinates the operations of the collector, receiver, receiver piping and solar auxiliary electric systems to ensure safe and proper operation of the entire integrated cogeneration plant. The solar master control system also receives appropriate status and data input information from the existing plant control systems. Operating at the highest level in the control hierarchy, the solar master control system issues commands to the control systems at the lower level of this hierarchy and receives feedback status information from these control systems. The system provides the capability for automatic start-up, normal operation, and shutdown of the collector, receiver, and receiver piping systems. The solar master control system also issues emergency shutdown commands. In addition, this system serves as a centralized data acquisition system which monitors, analyzes, and displays all critical solar system and subsystem parameters.

The solar auxiliary electric system provides electrical power to all solar facility auxiliary loads. The auxiliary loads are defined as electrical loads required by the various solar systems during start-up, shutdown, and normal operating modes of the solar facility. Two categories of electrical power are required: normal ac power and uninterruptible ac power. Normal ac power is used to supply power to collector, receiver, and receiver piping system electrical loads, as well as miscellaneous electrical loads such as lighting, heating, ventilation, and air conditioning. Uninterruptible ac power is used to supply power to the solar master control system computers and other critical control and instrumentation, where an interruption of power for even a few cycles cannot be tolerated.

Key features of the conceptual design are presented in Table 1.

Solar Facility Performance

The performance of the conceptual design was determined through simulation modeling of the solar cogeneration facility. Individual characteristics and performances of the collector, receiver, receiver piping, solar master control, and auxiliary systems provided the inputs to the Solar Thermal Electric Plant Performance Evaluator (STEPPE) simulation program. The collector system performance model is part of OPTICS, Black & Veatch proprietary software, developed for central receiver collector/receiver systems. This engineer/computer interactive set of programs is used for design optimization. These simulations were used with a weather effect-modified ASHRAE* clear air model of the direct insolation to calculate net annual thermal energy produced by the solar facility for electric power generation and process steam generation.

*American Society of Heating, Refrigerating, and Air Conditioning Engineers.

Table 1. Conceptual Design Summary

Key Feature	Description
1. Site Location	Cimarron River Station, Liberal, Kansas.
2. Facility Characteristics:	
a. Year of Commercial Operation	1963 (Unit 1); 1967 (Unit 2)
b. Turbine Type	General Electric tandem compound, double flow, non-reheat condensing turbine rated at 44 MWe (60 MWe at overpressure).
c. Turbine Inlet Temperature and Pressure	
— rated conditions	510 C (950 F)/8.72 MPa (1,265 psia)
— overpressure conditions	510 C (950 F)/9.58 MPa (1,390 psia)
d. Turbine Exhaust Steam Pressure	38.1 mm (1.5 in) Hg absolute
e. Process Fluid	Steam
f. Process Fluid Temperature and Pressure	204 C (400F)/550 kPa (95 psia)
3. Design Point:	Noon, March 21
4. Receiver:	
a. Receiver Fluid	Water/steam
b. Configuration	External, absorber 210-degree sector of 6.71 m (22 ft) diameter by 9.45 m (31 ft) high cylinder with closure doors.
c. Type	Drum with pumped circulation
d. Elements	Economizer, boiler, superheater
e. Output Fluid Temperature	520 C (968 F)
f. Output Fluid Pressure	11.07 MPa (1,605 psia)
5. Collector Field:	
a. Number of Heliostats	1,057
b. Reflective Area per Heliostat	52.77 m^2 (568 ft^2)
c. Cost Installed	\$215/m^2
d. Type of Heliostat	DOE Second generation
e. Field Configuration	North, 156 degree sector
f. Total Reflective Area	55,780 m^2 (600,103 ft^2)
g. Total Collector Field Area	222,000 m^2 (55 acres)
6. Storage:	None
7. Capital Cost	
a. Total Capital Cost: 1980 dollars including all capital, start-up, and checkout costs but excluding O&M (based on installed heliostat cost of \$215/m^2)	\$33,241,168
b. Total Capital Cost: 1980 dollars using installed heliostat cost of \$260/m^2	\$36,684,289
8. Construction Time	2 years
9. Solar Facility Contribution at Design Point (based on turbine valves wide open, overpressure operation):	
a. Receiver Output	37.13 MWt
b. Electrical Power, net	15 MWe
c. Mechanical Power	0
d. Process Power	3.7 MWt
10. Solar Facility Contribution, Annual (based on plant load model)	
a. Receiver Output	66 GWht
b. Electrical Energy	20.0 GWhe
c. Mechanical Energy	0
d. Process Energy	13.5 GWht
11. Solar Fraction:	
a. Design Point	0.247
b. Annual	0.102
12. Annual Fossil Energy Saved	48,100 barrels of oil equivalent
13. Type of Fuel Displaced:	Natural gas and coal
14. Ratio of $\frac{\text{Annual Energy Produced:}}{\text{Total Mirror Area}}$	1.18 $\frac{\text{MWht}}{m^2}$
15. Ratio of $\frac{\text{Capital Cost (1980 dollars)}}{\text{Annual Fuel Displaced}}$	$\frac{\$406.87}{\text{MWht}}$
16. Site Insolation (direct normal):	
a. Design Point	950 W/m^2
b. Annual daily average	6.1 kWh/m^2 day
c. Source	"On the Nature and Distribution of Solar Radiation," March 1978 HCP/72552-01
d. Site Measurements	Started January 15, 1981, will continue for one year
17. Cogeneration Utilization Efficiency*	41.0 per cent

*Defined by $\frac{\text{MWhe + MWht}}{\text{MWh}}$

Where: MWhe is net useful electrical energy
MWht is net useful thermal energy
MWh is total energy input to the facility (fuel plus solar energy incident on the receiver) using annual energy in megawatt-hours

The design point and annual average efficiency stair steps are shown in Figure 6. At the design point the solar to thermal energy conversion efficiency is 70.0 per cent, with solar contributing 24.7 per cent of the power requirement of both electric generation and process steam. On an average annual basis, solar would satisfy 10.2 per cent of the Cimarron River Station process steam and electric generation requirements, thereby displacing natural gas equivalent to 48,100 barrels of oil annually.

Economic Analysis

The economic evaluation of the solar cogeneration facility at Cimarron River Station was based on the following considerations.

- Construction cost estimate.
- Owner's cost.
- Operating and maintenance cost estimate.
- Western Power fuel cost projections.
- Western Power economic criteria.

The construction cost estimate, $28,227,000 in July 1, 1980, dollars, is based on the conceptual design of the solar facility systems, site improvements/facilities, and modifications to the existing Cimarron River Station facility. The capital cost of each system and its fraction of the total cost are given in Figure 7. Heliostat costs are estimated to be $215/m^2. A contingency of 10 per cent is added to each cost element. The Owner's cost, in July 1, 1980, dollars, is projected to be $5,014,943, and consists primarily of AFUDC (allowance for funds used during construction) and taxes. The estimate of annual operating and maintenance cost is $135,610, expressed in July 1, 1980, dollars; this cost is allocated to major accounts as shown in Figure 8. The fuel cost and projected escalation rates are given in Table 2. In addition, the financial parameters used in the economic analysis are presented in Table 3.

Table 2. Fuel Cost Projections

Fuel	1980 Cost ($/MBtu)	Projected Escalation Rate (Per Cent)
Natural Gas	1.86	–
1981	–	14.5
1982	–	13.4
1983 – 1990	–	12.0
1991 – 2000	–	11.0
Coal	1.10	–
1981	–	12.2
1982	–	10.7
1983	–	10.1
1984 – 1985	–	10.0
1986 – 1990	–	9.0
1991 – 1995	–	8.0
1996 – 2000	–	7.0

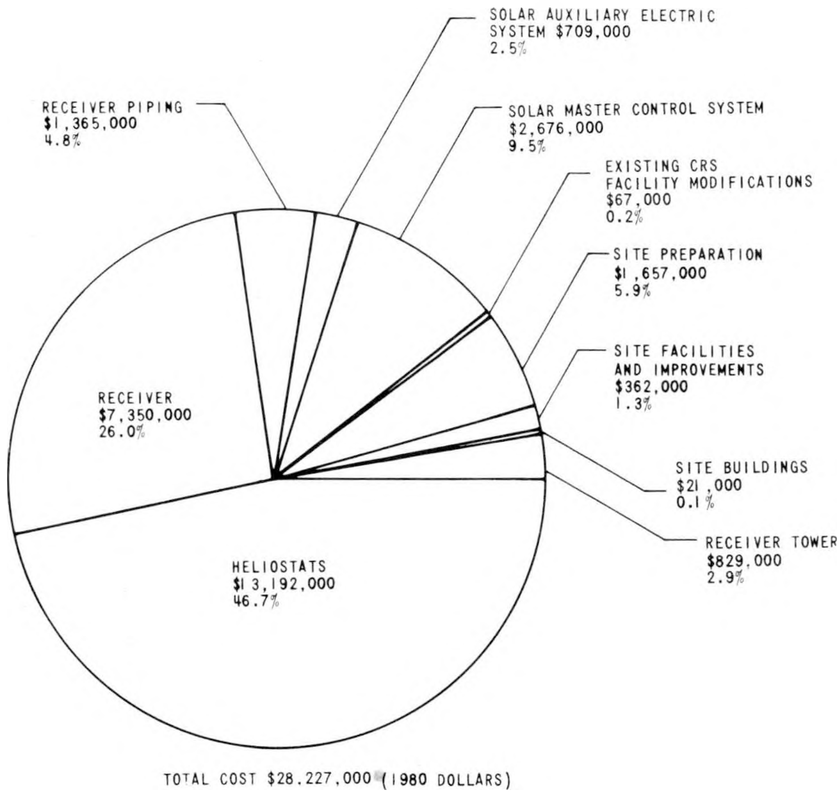


Figure 7. Construction Cost Estimate

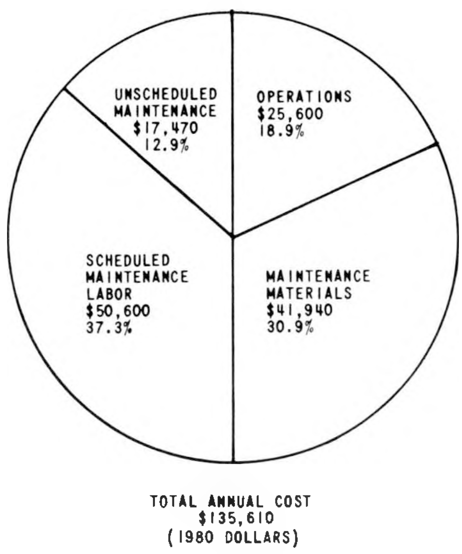
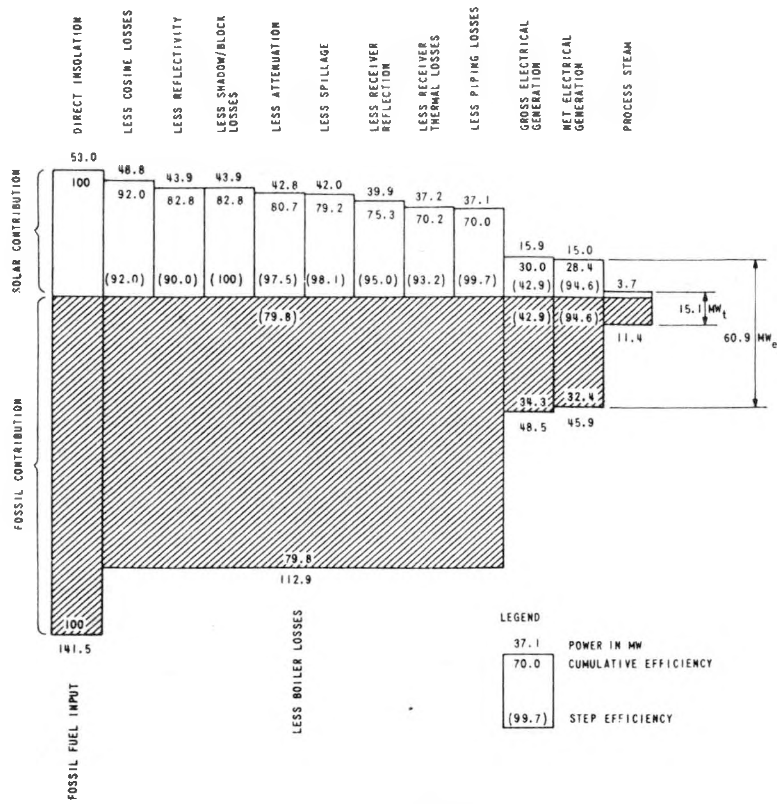
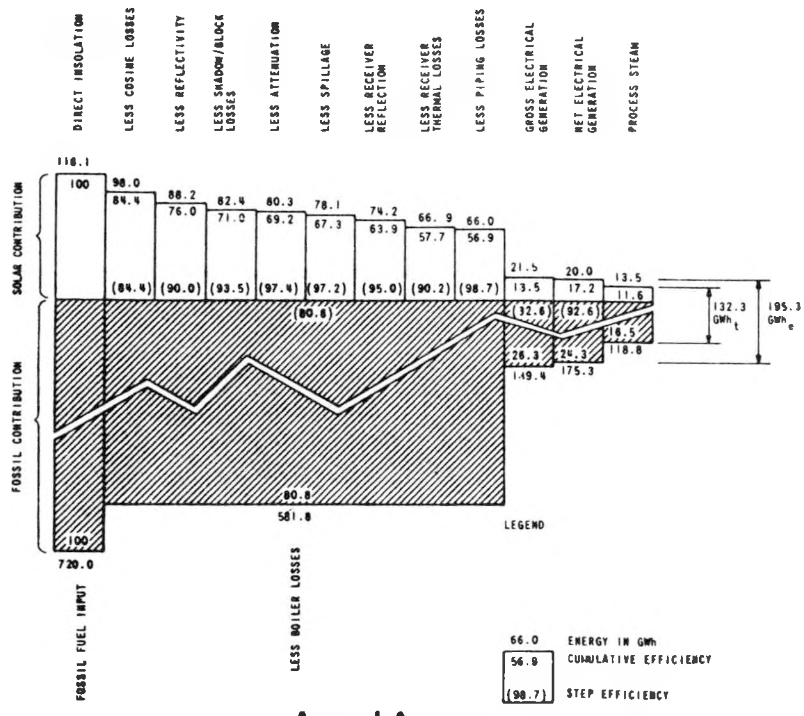


Figure 8. Operating and Maintenance Cost Estimate



March 21, Noon



Annual Average

Figure 6. Design Point and Annual Efficiency Stairsteps

solar facility reduced total system fuel requirements. The solar facility cost is the cumulative present worth of fixed charges from 1986 through 2000.

Table 4. Value of Cimarron River Station Solar Facility

	NHC Operates Through 2000	NHC Ceases Operation by 1986
Capacity Deferral Savings*	13.46	13.46
Fuel and O&M Savings*	4.30	4.40
Value of Solar Facility*	17.76	17.86
Solar Facility Cost*	59.46	59.46
Value as a Per Cent of Cost	29.9%	30.0%

*Expressed in millions of dollars discounted to 1986.

Table 4 shows that the value to Western Power of the solar facility is about 30 per cent of the solar facility cost. This value results primarily from incurring the higher system fixed charges of the solar facility beginning in 1986. Further, savings from reduced consumption of natural gas from 1986 through 1993 are largely offset by the displacement of coal from 1994 through 2000. Thus, only a limited capital expenditure would be cost-effective within the utility economic evaluation framework.

Sensitivity analyses were performed to identify the effect on value to Western Power of three factors.

- Fossil fuel prices.
- Solar facility life.
- Solar components costs.

The sensitivity analyses results, shown in Figure 9, support the basic conclusion of the economic analysis, and indicate that the value of the solar facility is largely insensitive to the factors studied.

Site Owner's Assessment

Western Power is predominantly a gas burning utility, with oil as a secondary fuel; therefore, the oil embargo and severe gas curtailments of the mid-1970's have had a major influence on the system. This, along with the enactment of the Fuel Use Act of 1978 and the country's continued dependence on foreign oil, are indicators that other sources of energy must be developed.

Because gas and oil are depleting and expensive resources, the option of converting Western Power generating units to coal was reviewed. Use of coal at the Cimarron River Station would involve major reconstruction of the existing plant; but, the major deterrent to coal use is

Table 3. Financial Parameters

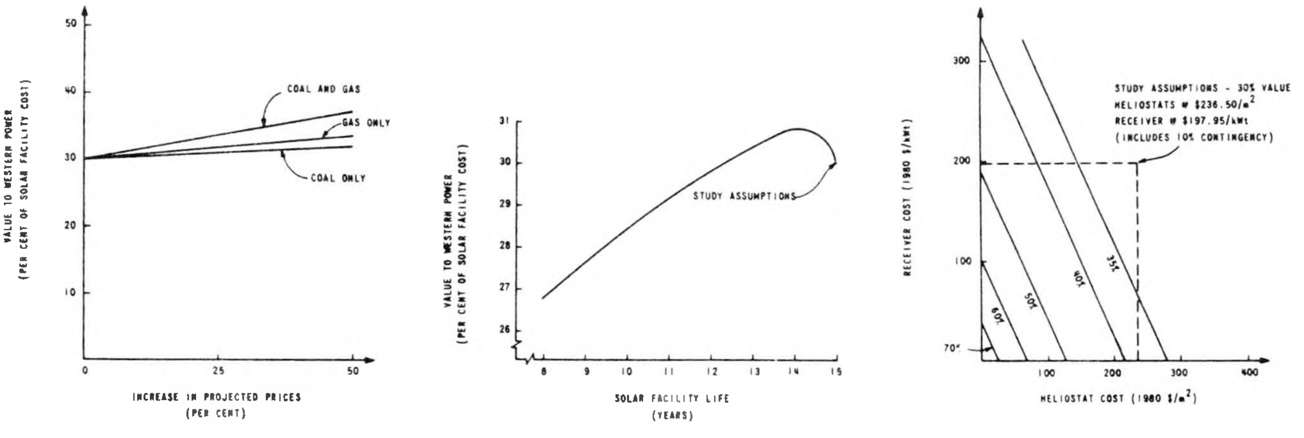
Factor	Per Cent
Discount Rate	13.45
Investment Tax Credit	11.0
AFUDC Rate	13.0
Property Tax Rate	1.45
Insurance Rate	0.45
General Inflation Rate	
1981	10.2
1982	8.7
1983 – 1990	8.0
1991 – 2000	7.0
Combined Federal and State Income Tax Rate	49.645
Fixed Charge Rate	
Solar	17.50
Combustion Turbine	16.27
Pulverized Coal	15.43

The value to Western Power of the solar facility addition at Cimarron River Station is explicitly defined as the additional investment cost that Western Power could incur for the solar facility without increasing the system's revenue requirements; this additional investment cost equals the savings associated with deferred capacity and decreased fuel and O&M costs. The methodology for calculating the value of the solar facility was based upon standard utility long-range generation expansion planning procedures and criteria. It involves analyzing revenue requirements of the capital investment, the investment related costs, and the fuel and O&M costs. The analysis yields cumulative present worth of comparative revenue requirements and identifies savings by comparing the solar plan with the no-solar base plan.

The analysis began with establishing the alternate generation expansion plans. Then, each plan was simulated using the Black & Veatch economic dispatch system simulation computer model; this model was adapted to the Western Power system. The simulation produced annual production costs which were combined with annual fixed charges to yield the total annual comparative revenue requirement. Comparison of revenue requirements for the 15-year evaluation period was made using Western Power's economic criteria.

The long-term operation of National Helium Corporation is dependent on gas industry economics and future availability of natural gas feedstocks. Since uncertainties surround both of these factors, the economic analysis addressed two "limiting" cases: one in which National Helium Corporation continues to operate through the year 2000, and one in which National Helium Corporation is not operating beyond 1985. The results of the value determination for these two cases are summarized in Table 4. For each case, Table 4 shows the savings due to capacity deferral and fuel and O&M requirements in 1986 discounted dollars. With the addition of the solar facility, the economic lifetime of Cimarron River Station can be extended from December 1993 to December 2000. The 7-year extension could allow the deferral of 60 MWe of new quick start combustion turbine capacity of the Western Power system, required to meet the system spinning reserve requirement. The fuel and O&M cost savings accrue because the

the fact that the existing plant is a 60 MW unit, which is far too small for economic coal conversion. The emission control equipment needed to meet environmental requirements and coal handling facilities for this size unit are just not an economic alternative.



EFFECT OF FUEL PRICES ON VALUE OF CRS SOLAR REPOWERING

EFFECT OF SOLAR FACILITY LIFE ON VALUE OF CRS SOLAR REPOWERING

EFFECT OF SOLAR COMPONENT COSTS ON VALUE OF CRS SOLAR REPOWERING

Figure 9. Sensitivity Analysis

Confronted with limited fuel options, the idea of solar energy stands out as an alternative energy source. For this application, it has several major advantages. First, the daily output curve of a solar plant is much like the system daily load curve. Second, it can be constructed faster and in smaller increments than a coal fueled plant. Third, it is readily adaptable to retrofit existing gas fueled facilities, shifting the source of energy from currently limited gas to infinite solar.

At the present time, unfavorable economics appear to be the major disadvantage. Current solar capital requirements are not competitive with that required to build comparable coal fueled systems. The difference must be considered in planning actions despite the ultimate advantage of sparing finite fossil fuels and helping prepare for new avenues of energy supply. Western Power is hopeful that a cost sharing arrangement will be provided for supportive funds necessary to balance the cost and further develop solar energy.

The second solar problem is the loss of output caused by cloud interruptions. The operating problems caused by solar interruptions can be solved with an existing unit. One of the trade studies for this project considered potential storage systems. In all cases, the addition of storage increased the lifetime cost and the complexity of the system. Western Power believes that parallel operation, at least in the development stages, provides a more flexible, more reliable and less expensive system. It should hold the most potential for economic solar applications in the near term.

The Cimarron River Station is in the heart of the high plains. It is surrounded by pastures, located in the Cimarron River Valley, 18 kilometers (11 miles) northeast of Liberal, along with two other major industrial complexes: National Helium Corporation and Panhandle Eastern Pipe Line Company. This remote location, along with its rolling landscape, is truly ideal for solar application. It has good access for construction and for the many interested visitors that the facility will attract.

The high plains area of western Kansas lends itself as an appropriate location for use of solar energy. Direct normal annual average insolation is approximately 6.1 kW/m^2 day. The terrain is open and has vast areas that are basically unproductive. The installation of a large collector field will not significantly affect the local ecology, scenic attractions or other land uses. Due to the fact that solar power emits no pollutants, this project will not affect local air or water quality.

This conceptual design study has gone into considerable detail, examining the possibility of supplementing Cimarron River Station's fuel supply with solar. The end result is a water/steam receiver system that parallels the existing gas fueled boiler. One of the major requirements in the beginning of the study was that the system must have very high reliability and assured performance. Western Power believes that this system meets that requirement and is operable, reliable, and a significant demonstration of solar potential.

Every effort has been made to design a system that is simple and cost-effective. The water/steam technology has been well-proven and, in Western Power's opinion, has the highest probability of being built on schedule and within budget. The simple design has helped reduce the risk of failure and of poor performance which would be very detrimental to the solar concept. Basic utility industry design will greatly simplify operator training, reduce operating problems, and provide operation safety.

Western Power believes that realistic costs have been used and system benefits have been fairly assessed in the economic analysis. Even though the analysis does not show solar to be cost competitive, it should be noted that this is a R&D facility and, by continual systems improvements and volume production, the cost of solar could become competitive with oil or gas generation in the foreseeable future.

FORT HOOD SOLAR COGENERATION FACILITY
CONCEPTUAL DESIGN STUDY

W. L. Dreier
McDonnell Douglas Astronautics Company

Project Summary

This study is one of several conceptual design studies authorized by the Department of Energy (DOE) to demonstrate the technical, economic and institutional feasibility of site-specific central-receiver solar cogeneration facilities, in which solar energy is collected and used to produce both high-grade energy for the generation of electricity and low-grade energy for industrial processes or space conditioning and other useful purposes.

DOE selected the McDonnell Douglas Astronautics Company (MDAC) to study the application of a solar cogeneration facility at the U. S. Fort Hood Army Base in Killeen, Texas. MDAC, with the support of the Department of the Army, Stearns-Roger (for A&E support), and the University of Houston Energy Laboratory (for field optimization support) studied the use of solar-heated molten salt to produce the steam for the generation of electricity and for room heating, room cooling, and domestic hot water for Complex 87000 at Fort Hood.

The following major conclusions have been reached relative to the proposed solar cogeneration facility at Fort Hood.

1. The proposed system is a practical application of solar cogeneration.

    - The system allows the maximum utilization of collected solar energy for cogeneration purposes.

    - A substantial savings of critical fossil fuels can be realized (equivalent to approximately 9,700 barrels of fuel oil per year).

    - The concept is technically feasible with minimum facility modifications and risks.

    - There are numerous other military applications possible with housing and service facilities similar to Complex 87000..

2. The first plant is marginally cost effective.

- The facility will cost $19,135,000 in 1980 dollars.
- Average operations and maintenance costs are $97,400 per year.
- The payback period is 24.3 years.
- Low displaced energy costs have been assumed.
- This basic design concept provides reasonably good economics at locations with high insolation and energy costs, assuming multiple applications (as low as $11M cost and 13 year payback).

3. A demonstration facility is required before large-scale deployment.

- The system can be operational within 31 months of authority to proceed.
- Fort Hood Complex 87000 is a good site for a demonstration facility.

There are several reasons why Fort Hood is a good location for the demonstration of a solar cogeneration facility. It has a very high annual consumption of electricity and natural gas and several studies for solar installations at Fort Hood have been conducted in cooperation with the Army since 1974. Adequate space adjacent to Complex 87000 is available for the collector field and other solar equipment. The existing facility requires minimum modifications to interface with the solar system, and the current energy system can be retained as a backup system. The design of the complex and its equipment represents a standard design that is being implemented at other military bases. The Army is committed to the development of solar energy systems at Fort Hood, and has encouraged the installation of a solar central receiver system at their Complex 87000. The Energy Resource Office of the Governor of Texas is also intensely interested in this project and has pledged its support.

The primary objective of this solar cogeneration facility study was to provide DOE with site-specific conceptual design data including facility performance, development plans, costs, economics, and other related information. The scope of this effort included the preparation of a system specification (Task 1), selection of a site-specific configuration (Task 2), facility conceptual design (Task 3), facility performance estimates (Task 4), cost estimates and economic analyses (Task 5), a development plan (Task 6), and related program management efforts (Task 7). There were no requirements for hardware development or testing during the contract phase.

Existing Facility Description

Fort Hood, which is one of the largest U. S. Army bases in the world, is located at Killeen, Texas, approximately midway between San Antonio and Fort Worth in a region of reasonably good insolation ($\sim$ 5 kWh/m^2/day). The climate consists of temperate, rainy winters and hot, dry summers with average precipitation of 76 cm (30 in)/year. The terrain is reasonably flat and well suited for a central receiver type solar system. Complex 87000, which is located at the eastern edge of the base, was selected for the solar cogeneration installation. Complex 87000 consists of a group of 20 buildings (450,633 ft^2 of total floor area) of contemporary Army design providing housing, food services, administration, dispensary, PX, storage, recreation and central energy for a brigade-size complement of troops (approximately 1650). A photograph of this complex is shown on Figure 1 with an artist's concept of the heliostat field superimposed. This complex is representative of many similar barracks complexes on this and other military bases.

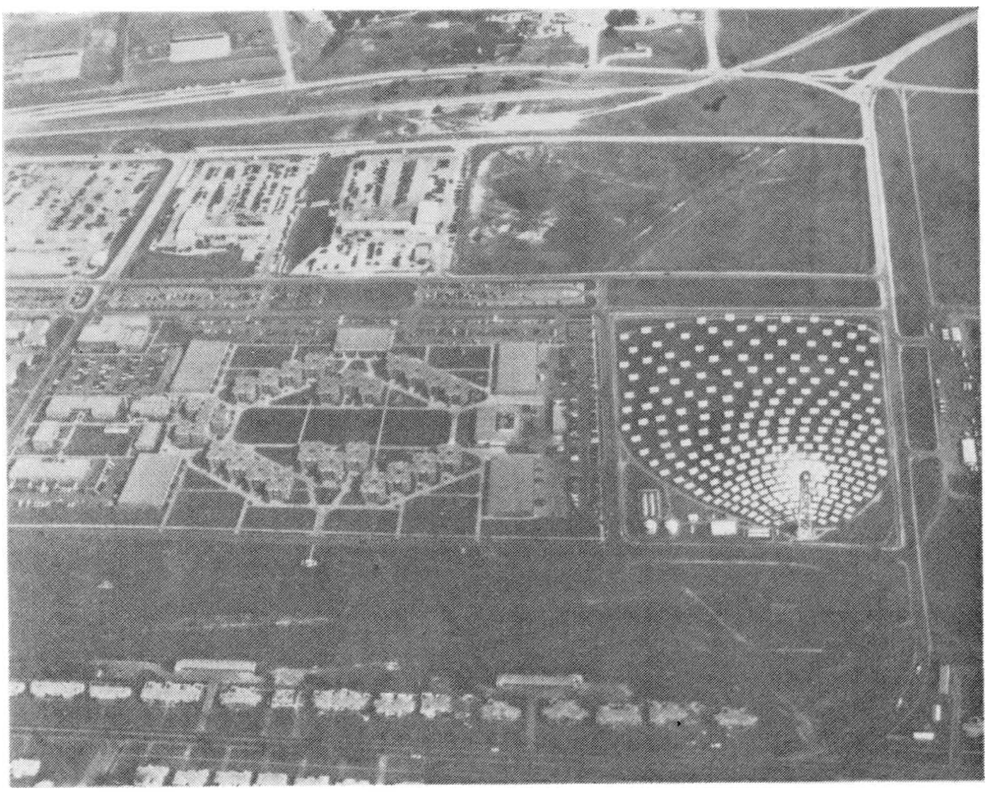


Figure 1. Fort Hood Solar Cogeneration Facility Installation

At Complex 87000, all thermal energy needs are provided from a central energy plant located at the eastern edge of the complex. Electricity, which is provided by the Texas Power and Light Company, is distributed from a base grid through an underground loop network to the buildings of the complex. Also, the power is used to operate two electrical compressors in the central energy plant which produce and distribute chilled water by underground lines throughout the complex for air conditioning in the summer months. Gas, which is provided by the Lone Star Gas Company, is used to operate two steam boilers in the central energy plant which produce and distribute steam by underground lines throughout the complex for year around water heating and room heating in the winter months.

The solar equipment and collector field will be located adjacent to the central energy plant in the open field to the east of the complex, as illustrated on Figure 1. All interfaces between the solar equipment and the complex will be made at the central energy building. No modifications are needed to any of the energy equipment or distribution network downstream of the central energy plant.

Conceptual Design Description

The Fort Hood solar cogeneration facility is a total energy system designed for both electrical power production and the generation of heat for space conditioning and domestic hot water. The baseline design is a solar central receiver concept utilizing a field of heliostats located to the north of a tower-mounted receiver. Cogeneration is accomplished by generating high-pressure, high-temperature steam, and expanding the steam through a turbine-generator to produce electricity, and utilizing the heat that would otherwise be wasted for space conditioning and the domestic water heating. A schematic of the solar equipment is shown on Figure 2.

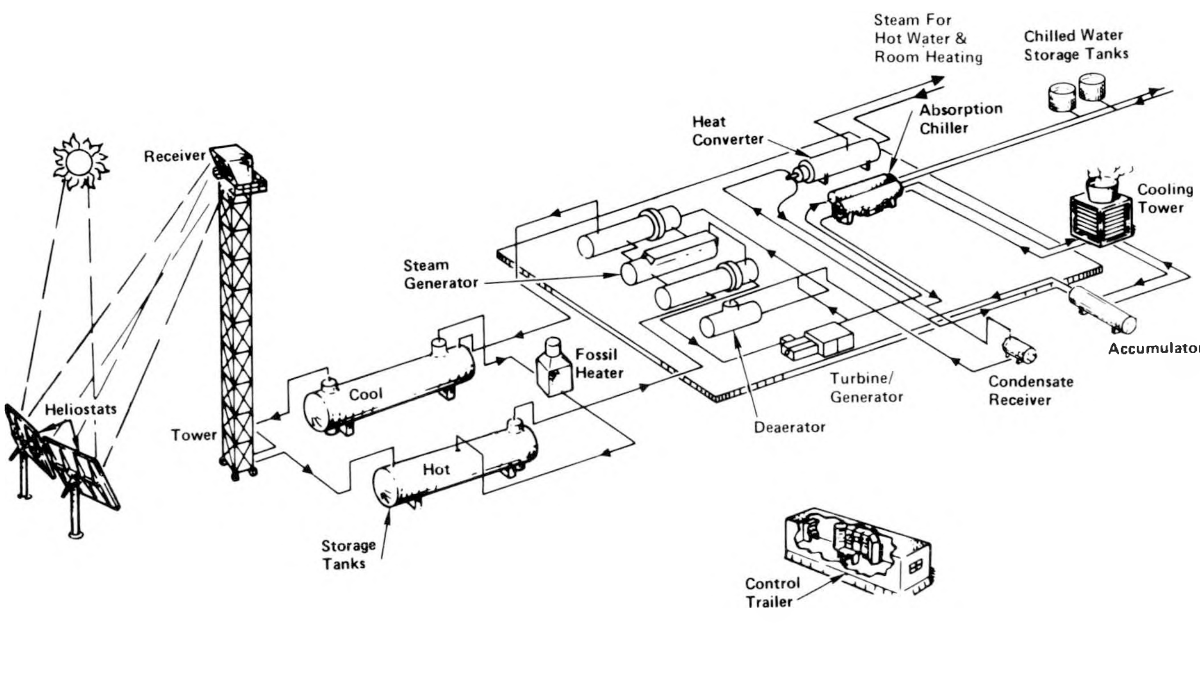


Figure 2. Solar Cogeneration Facility Arrangement

A field of heliostats concentrates solar insolation on a partial cavity tower-mounted receiver. To absorb the heat, a heat-transfer salt (HITEC) is pumped through the receiver and routed to storage tanks. The stored heat is then transferred to a water-steam loop via a steam generator producing superheated steam. The steam is expanded through a multistage steam Rankine axial turbine which drives a generator producing electricity. Turbine exhaust steam is used to provide room heating, air conditioning, and hot water for the Army complex. Appropriate thermal storage tanks are used to provide the necessary steam and chilled water to the complex for 24-hour operation. When the complex energy demands cannot be supplied from solar energy, the plant is capable of providing thermal energy with an auxiliary gas-fueled heater. If the solar plant is non-operational for maintenance activities or other reasons, the energy requirement of the complex can be satisfied by existing boilers and refrigeration equipment. The major components and energy/fluid flow paths of the baseline system are illustrated schematically in Figure 3.

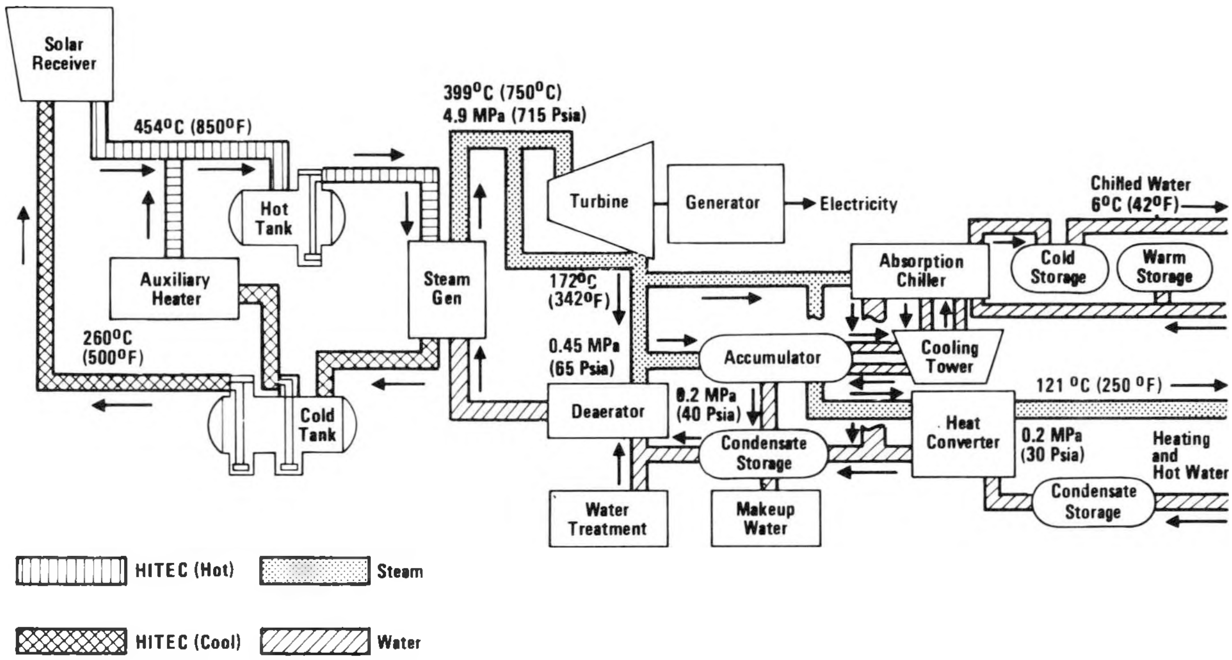


Figure 3. System Flow Schematic

The baseline collector field consists of 242 MDAC second generation heliostats (mirror area of 56.84 m^2 per heliostat) located in a 61,990 m^2 (15.3 acre) field to the east of the complex. A free-standing steel tower 53.2 m (175 ft) in height is located at the south edge of the collector field. The receiver, which is mounted on the tower, is a partial cavity configuration of coiled stainless steel tubes designed for an energy output of up to 8.9 MW_t. The receiver working fluid is HITEC, a molten salt solution which is heated to 454°C (850°F) in the receiver and subsequently circulated into high temperature storage tanks near the base of the tower. Two tanks, containing hot and cold HITEC, permit the storage of up to 20 MWh_t of excess solar thermal energy as sensible heat during periods of high insolation for use by the cogeneration system during periods of low insolation. During cloudy days or during periods of excessively high energy demand, a gas-fired HITEC heater will provide heat for the system.

The stored HITEC is subsequently pumped through a kettle-type steam generator producing superheated steam at a temperature of 399°C (750°F) and pressure of 4.9 MPa (715 psia). The steam is expanded through a steam Rankine turbine which drives an electrical generator producing up to 600 kW of electricity. The flow of HITEC to the steam generator and steam to the turbine is independent of the receiver flow and is regulated by the demand for turbine inlet steam. The electricity produced is integrated into the existing electrical network for the complex by means of appropriate switches, transformers, and controls.

The turbine is designed to exhaust steam at a back pressure of 0.45 MPa (65 psia) and 172°C (342°F) for the operation of equipment for room heating, air conditioning, and hot water for the complex. Excess turbine exhaust steam is routed through an accumulator where it is condensed and stored under pressure and the unusable energy is rejected to the cooling tower. Upon demand turbine exhaust steam is passed through a heat exchanger to generate steam at 0.2 MPa (30 psia) and 121°C (250°F) in a separate loop for distribution to the complex through existing steam lines for domestic hot water and room heating. The turbine exhaust steam can also be used to operate a two-stage absorption chiller which provides chilled water at 6°C (42°F) for distribution to the complex through existing water lines for room air conditioning. Two chilled water storage tanks are included to provide chilled water during periods of high demand.

The cooling tower, located in the southwest corner of the field, will be used to reject heat from the absorption chiller and steam accumulator. This evaporative mechanically-induced draft cooling tower is rated at 5 MW_t (17.3×10^6 Btu/hr).

System Performance

The performance of the Fort Hood solar cogeneration facility is very dependent upon the available insolation at the site and the efficiency in which this energy is collected and utilized by the system. The average annual insolation at Fort Hood is 4.9 kWh_t/m^2 per day, which is sufficient to operate a central receiver type solar system.

The annual efficiency of the proposed collector system is shown on Figure 4. Losses have included cosine effects, blocking and shadowing, reflectivity, layout and boundary losses, heliostat availability, attenuation, receiver interception, absorptivity, thermal and piping losses. As indicated, the overall collection efficiency is 0.524 to the bottom of the tower. The efficiencies of the remainder of the cogeneration facility depend upon the energy load demands and the system operating mode at any particular time.

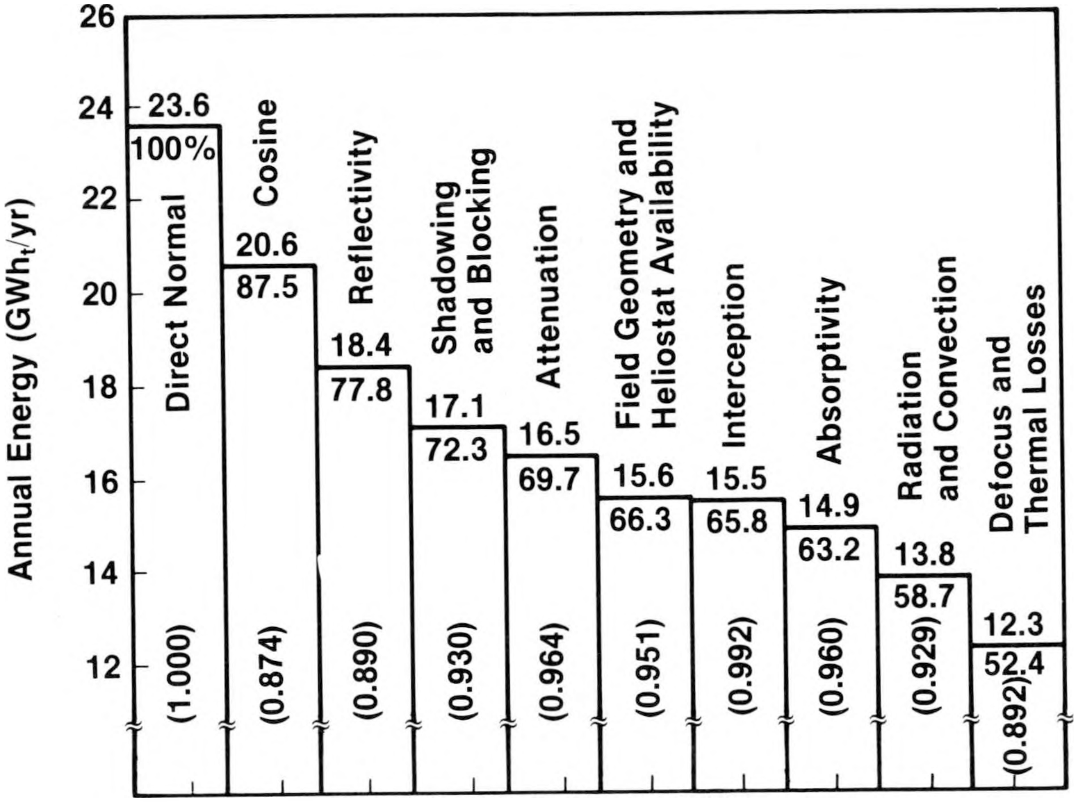


Figure 4. Annual Energy and Efficiencies

The thermal and electrical load demands of Complex 87000 vary significantly on both an hourly and seasonal basis. Electrical loads and thermal loads for domestic hot water are not much affected by the seasons, as would be expected. However, the seasonal variations result in large demands for heating in the winter and air conditioning during the summer. Consequently, the resultant thermal demand profile requires two to three times as much thermal energy during the winter and summer as is needed during the spring and fall. Thus, a solar system sized to match the minimum spring/fall demands will fall far short of meeting the winter/summer needs. Conversely, a system sized for the winter and summer demands will have excessive thermal spillage during the spring/fall months. Optimization studies have indicated that it is cost effective to size the system larger than the minimum demands and spill the excess thermal energy. In order to provide a closer match between collected solar energy and thermal demands, an absorption chiller was chosen to replace existing electrical refrigeration machines. The proposed system is sized to meet most of the thermal and electrical energy demands throughout the year.

Hourly variation in loads had a significant impact on the design of the plant and the storage capabilities required. The operational procedures of the facility will entail 24-hour turbine operation at varying power levels with energy being stored to meet peak thermal load demands. During turbine operation in the summer time, chilled water generated by the absorption chiller for air conditioning will be stored in tanks for peak demands. During the winter months, the cogeneration facility will be able to continuously meet all demands for space heating and domestic hot water.

An annual energy balance showing the flow of energy through the proposed solar cogeneration system is shown on Figure 5. The diagram includes energy input from the solar field and auxiliary heater, losses and rejected energy, and the distribution of energy for electric power, air conditioning, room heating and domestic hot water. As shown, most of the energy input comes from solar conversion, and most of the energy output is used for the thermal demands of the complex.

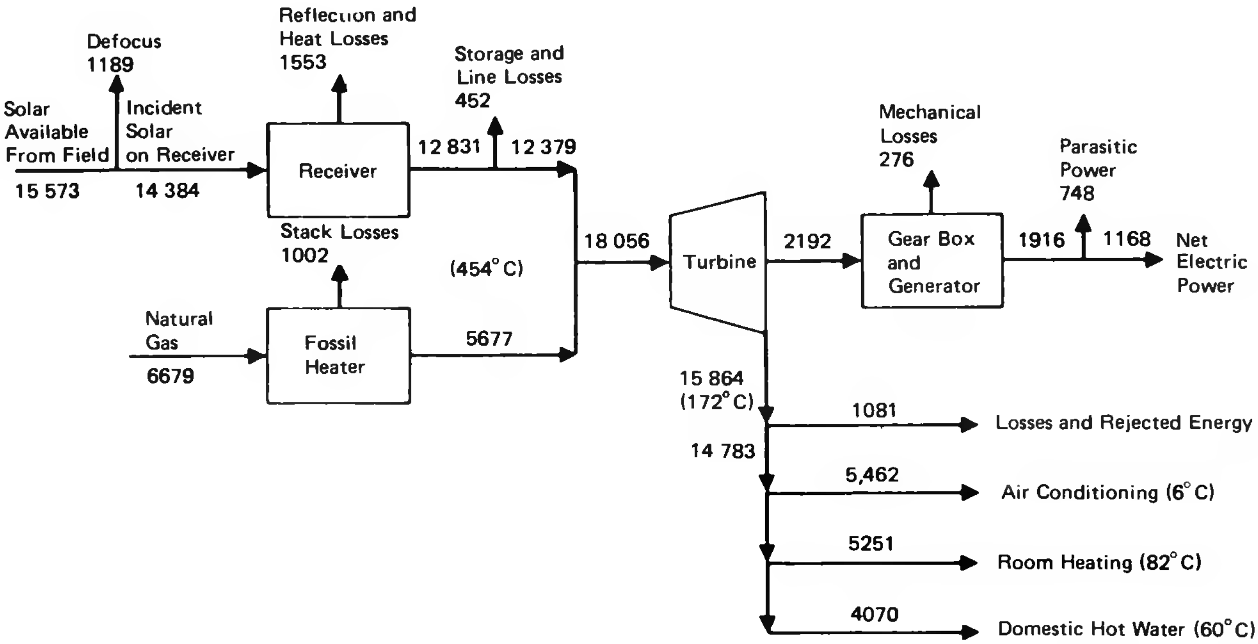


Figure 5. Annual Energy Balance (MWh Per Year)

A summary of annual energy usage and energy saved by the solar cogeneration facility at Complex 87000 is shown on Table 1. As indicated, the solar system will result in a significant savings in both gas and electricity. The total savings are the equivalent of approximately 9,709 barrels of oil per year. These savings are compatible with the overall program objectives of reducing the use of critical fossil fuels.

	Current Annual Usage		Complex with SCF Annual Usage		Annual Savings		Equivalent Annual Oil Savings		
	Power (MWh_e)	Gas (MWh_t)	Power (MWh_e)	Gas (MWh_t)	Power (MWh_e)	Gas (MWh_t)	Power (Bbl Oil)	Gas (Bbl Oil)	Total (Bbl Oil)
Electric Base (W/O A/C)	2900	—	1355	—	1545	—	3078	—	3078
Air Conditioning	2237	—	377		1860		3705		
Room Heating	—	5251	—	5677	—	3644	—	2926	6631
Water Heating	—	4070	—		—		—		
Total	5137	9321	1732	5677	3405	3644	6783	2926	9709

1 Bbl Oil = 502 kWh_e
= 1,700 kWh_t

Boiler Eff = 80%
Fossil Heater Eff = 85%

Table 1. Energy Saved

Economic Findings

Preliminary estimates have been made of the capital investment costs, annual operating and maintenance costs and an economic assessment of the proposed Fort Hood solar cogeneration facility.

Capital Investment Costs

Price estimates are given in 1980 dollars. Capital expenditures were assumed to be made during 1984 for operational capability on January 1, 1985. Heliostat costs of \$260/m^2 (DOE supplied) were used. A 10% contingency and 3.5% composite management fee were included for all items. Program life was assumed to be 25 years.

Capital investment costs are summarized on Table 2. As noted, the total costs of the facility are approximately \$19.1 million, of which \$3.1 million are non-recurring costs. The high cost subsystems are the collector (27%), receiver (13%), plant control (14%), and electric power generating subsystems (20%), which together account for 74% of the total facility cost. If this type cogeneration facility could be installed at several other locations, the capital investment cost of each installation would drop to as low as \$10.5 million (Nth unit which represents the average cost of 100 similar facilities installed at 10 per year over 10 years). This cost reduction would occur as a result of higher production/lower cost units and design improvement.

Table 2 - Facility Capital Investment Costs
(Thousands of 1980 dollars)

	Non-recurring	Recurring	Total	Nth
5100 Site improvements	25	856	881	809
5200 Administrative areas	12	403	414	382
5300 Collector subsystems	158	5,115	5,273	2,158*
5400 Receiver tower subsystems	427	2,120	2,548	1,739
5500 Plant control subsystem	1,624	1,087	2,710	460
5600 Fossil energy subsystem	9	304	313	288
5700 Energy transport and storage subsystem	40	1,660	1,701	1,532
5800 Electric power generating subsystem	713	2,957	3,671	1,693
5900 Other useful thermal energy systems	47	1,578	1,624	1,446
5000 Total facility costs	3,056	16,080	19,136	10,506

* Based on heliostat costs of 110 $ per m^2.

Note: All costs include proportional allocation for A&E, solar integrator, construction management, contingency and composite management fee.

Operating and Maintenance Costs

Operating and maintenance costs for the solar cogeneration facility after the first year of operation are expected to average $97,400/year, excluding fuel costs which are included in the economic analyses. The percentage breakdown is approximately operations (23%), maintenance materials (42%), and maintenance labor (35%). First year costs were estimated to be $180,000.

The net annual energy and dollar savings in 1980 dollars from the operation of the Fort Hood solar cogeneration facility at Complex 87000 are as follows:

Item	Annual Energy Savings	Displacement Credit Rates	Annual Dollar Savings (1980 dollars)
Electricity	3,405 MWh_e	$0.021/$kWh_e$	$ 71,505
Natural gas	16,490 x 1000 CF	$2.51/1000 CF	$ 41,390
		Total annual savings	$112,895

This annual energy savings is equivalent to 9,709 barrels of oil per year. Since the current site-specific displacement credit rates are so low (equivalent to approximately $11/bbl oil), the annual savings are not very substantial. However, over the life of the program, the costs of natural gas and electrical power are expected to rise significantly, which will result in significant savings.

Economic analyses assuming energy costs at the site and inflation factors specified by the DOD, indicate a payback period of 24.3 years and a 3.7% rate of return. A similar economic assessment has been made of the Nth plant, which represents the average of 100 plants. Assuming energy costs typical of California, a payback period of 13 years was determined, yielding an 11.3% rate of return. These results imply that good economic benefits will result with the installation of additional cogeneration systems similar to the Fort Hood facility in regions of high fuel costs.

As stipulated by DOD criteria, a solar system will be considered cost effective if the original investment cost differential can be recovered over the expected life of the facility, exclusive of O&M costs. The proposed solar cogeneration facility at Fort Hood meets these criteria, and can be the important initial step in the installation of such solar facilities at other military bases.

CENTRAL RECEIVER TEST FACILITY (CRTF)

J. V. Otts
Sandia National Laboratories, Albuquerque

FY81 MAJOR ACTIVITIES

<u>Receiver Testing</u>

- Molten Salt Receiver - Martin Marietta
  - completed ~5ØØ hours solar testing
  - hosted a salt receiver workshop
  - provided "hands on" operation to utility/industry groups
  - removed from CRTF 5/81
- Sodium Cooled Receiver Panel - ESG, Rockwell International
  - installed GE sodium loop and ESG receiver
  - installed/checked out RTAF system
  - checkout/sodium fill/hoist to top/test 1Ø/81
  - test completion 2/82

<u>Storage Testing</u>

- Molten Salt Storage - Martin Marietta
  - construction initiated at CRTF
  - complete construction/checkout 12/81
  - test completion 4/82

Heliostat Testing

- completed 2nd generation heliostat evaluation
  ARCO, Boeing, MMC, MDAC
- completed Barstow heliostat evaluation

- continue "life cycle" program
  2nd generation heliostats
  Barstow heliostat (3 ea)

CRTF General

- incorporated new control/data system
  faster data rate
  improved experimenter interface
  decreased data turn around

- 222 heliostats
  accumulated 358,706 hours since 1977
  maintain 95% operational
  rain wash only (77% to 83% reflectivity range)

- high intensity flux gage calibration capability 12/81

FINANCIAL ASPECTS OF CENTRAL RECEIVER SYSTEMS

T. H. Springer
J. K. Ives
A. Z. Frangos

Rockwell International
Energy Systems Group
Canoga Park, California

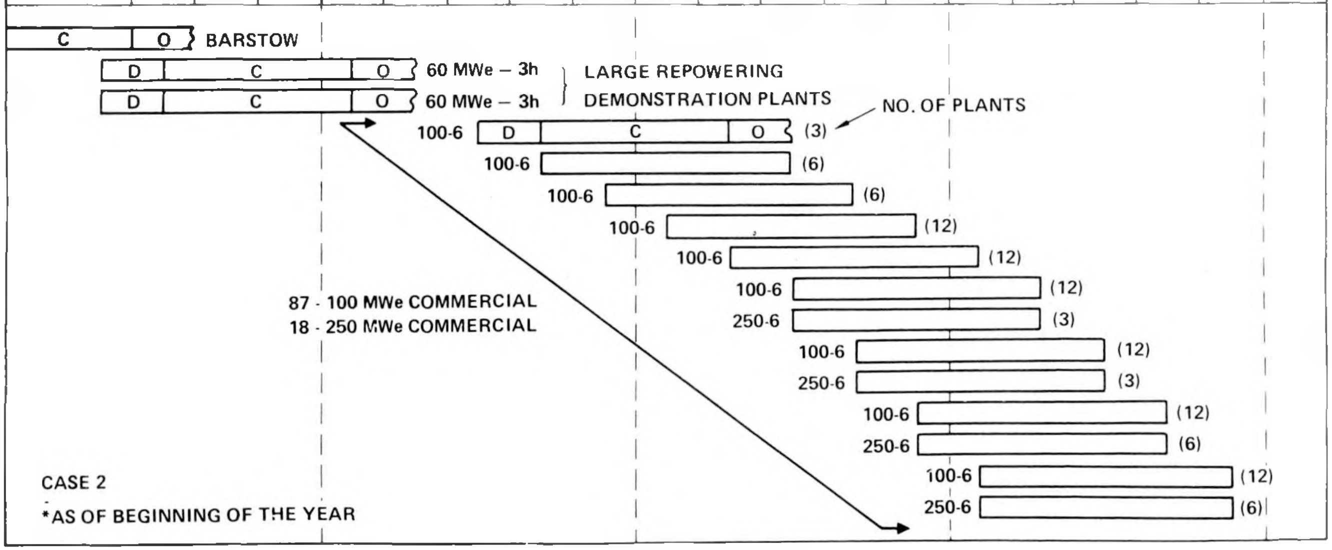
Contract Results

A $48,000 contract on the financial aspects of commercializing solar central receiver systems for electric power production has been completed under DOE funding. This work provides quantitative estimates of the investments required by government, utilities, and the manufacturing sector to meet the displacement goals for central receiver technology. Commercialization requires that central receiver systems meet the economic criteria used by industry to select systems for capital investment. If these systems cannot offer comparability to alternate energy sources in present and expected cost (weighted by perceived risk), then industry simply will not invest in the equipment. Initial solar repowering and stand-alone electric utility plants will not have economic comparability with alternative energy sources. A major factor for this is that initial (first-of-a-kind) heliostat costs will be high. As heliostat costs are reduced due to automated manufacturing economies, learning, and high-volume production, central receiver technology will become more competitive. Under this task, several scenarios (0.1, 0.5, and 1.0 quad/year) were evaluated to determine the effect on commercial attractiveness and to determine the cost to government of commercializing solar central receivers.

Cost of Commercialization

One case considered was meeting the national goal of providing 0.5 quads/year with solar by the year 2000 by the utility sector. It will be necessary to demonstrate technological feasibility as well as to construct many commercial-size plants. Many scenarios can be hypothesized, with variables such as the size of demonstration plants, the number of demonstration plants needed, the number of scaleup steps to a commercial-size plant, the time delay between demonstration plants to show operational feasibility, and the initiation of commercial-size plants. Figure 1 is one example of how we might reach this goal. To demonstrate feasibility, there should be several demonstration plants; the Barstow 10-MWe pilot plant comes on-line in 1981, and on-line operation by 1985 for at least two repowering plants of medium size (60 MWe

80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	2000
QUADS/YR (CUM) *						0.0036	0.004	0.004	0.004	0.004	0.004	0.015	0.036	0.0555	0.104	0.148	0.218	0.292	0.392	0.492
MWe (CUM) *						120	120	120	120	120	120	420	1020	1620	2820	4020	5970	7920	10,620	13,320
HELIO/YR x 1000				8	8	–	–	–	–	25	76	101	152	203	266	330	393	456	(456)	
HELIO CUM x 1000		2	2	10	18	18	18	18	18	43	119	220	372	575	841	1171	1564	2020		
HELIO COST $/m^2				220	220					132	108	103	103	103	103	101	101	101		
PLANT COST $/MWe-HA				825	825					556	474	430	430	430	430	426	426	426		



80-D11-109-4

Figure 1. Electric Utility Commercialization Plan (0.5 Quads by Year 2000)

with storage) is needed. A 2-year period is allowed for the demonstration repowering plants to show utilities the operating aspects of a solar plant with respect to the demands of the utilities' electrical network. At this point, most of the risk aspects of new technology would have been eliminated, and full-scale implementation of commercial-size solar plants could be initiated. By the year 2000, 87 100-MWe and 18 250-MWe plants would be operational, thus achieving the national goal of 0.5 quads/year.

While government subsidies would be required for the uneconomic portion, not all of the above plants would need to be subsidized. Figure 1 has presented the cumulative number of heliostats produced each year. As the heliostat costs decrease, the total plant costs decrease as shown in Figure 2.

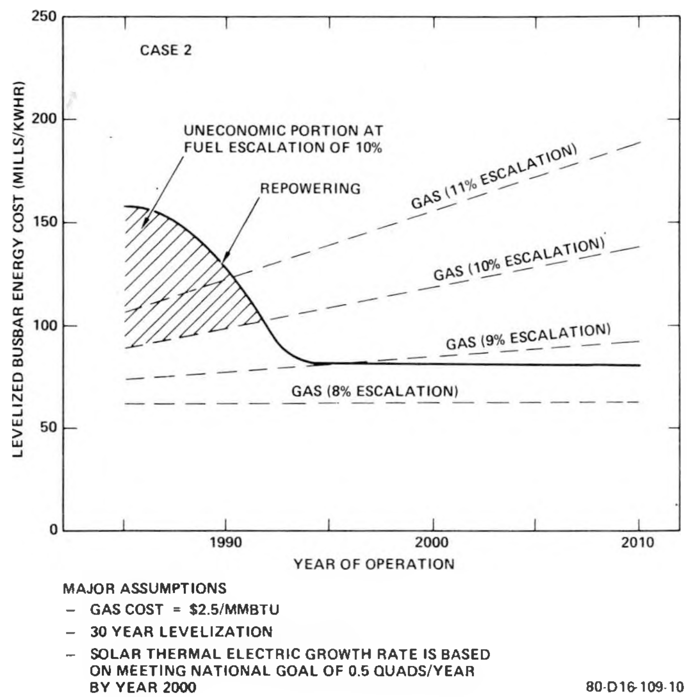


Figure 2. Solar Repowering BBEC vs Gas Fuel Savings BBEC

The levelized Busbar Energy Cost (BBEC) of solar repowering plants with a life of 30 years is compared to the BBEC of the gas the solar repowering plant would replace. In the year 1992, the solar repowering plant becomes economically competitive if a 10% gas escalation rate is assumed (2% above general). At this time, government subsidies would cease and the commercial marketplace would take over. The break-even point for heliostat costs in 1992 would be $103/m^2$ in 1980 dollars. The difference in BBEC before 1992 represents a measure of the plant subsidy required to induce utilities to select central receiver systems. The total plant subsidy during a 10-year period would be $481 million (1980 dollars).

Additional costs for production facilities required to produce the heliostats and other specialized components (receiver and steam generators) were considered. The assumption is that solar equipment manufacturers would not invest in production facilities for a component that does not have a commercially viable market. After 1992, manufacturers would, of their own accord, continue to invest their own money. Until that time, manufacturers must invest $357 million in heliostat facilities and $127 million in balance-of-plant facilities. Government subsidies or guarantees would be required to cover this cost.

Government Incentives

Several approaches for government incentives were considered. They are classified on the basis of the government relationship to the utility and manufacturing sectors and are as follows:

1) Utility/government cooperative
2) Manufacturer/utility/government cooperative
3) Manufacturer/government cooperative.

The three approaches are illustrated in Figures 3 through 5.

In the utility/government cooperative, manufacturers would require a higher return on heliostats and other components in order to amortize the facilities over the initial receiver plants. This would raise the total plant subsidy to $745 million. The other two approaches require government guarantees that there is a long-term market for solar central receivers. The second approach would require government investment or guaranteed loans of $484 million (1980 dollars) to the manufacturing sector with a return to government on that money in the form of royalties or interest, respectively. The manufacturer/government cooperative would consist of a long-term contract by government to purchase a specified number of heliostats at a given price from one or more manufacturers. The government, in turn, would sell these heliostats to utilities at a price compatible with an acceptable BBEC, for a net deficit of $481 million.

Figure 6 illustrates the government cash flow for these three types of incentive. Because the incentives to manufacturers carry a government commitment to create a long-term market, the last two types of incentives carry a certain risk if the program is discontinued before commercial viability. The dollar amount of that risk is indicated in Figure 6.

The four cases considered in the study are:

Case 1 — 0.1 quad with staggered demonstration plants

Case 2 — 0.5 quads with a 2-year delay between demonstration plants and the commercial plants

Case 3 — 0.5 quads without a 2-year delay between demonstration plants and the commercial plants

Case 4 — 1.0 quad with a 2-year delay between demonstration plants and the commercial plants.

Results are shown in Table 1 for the four cases. The surprising result is that the total cost to government is very insensitive to the total energy goal level and approaches in timing for implementing the demonstration and initial commercial plants.

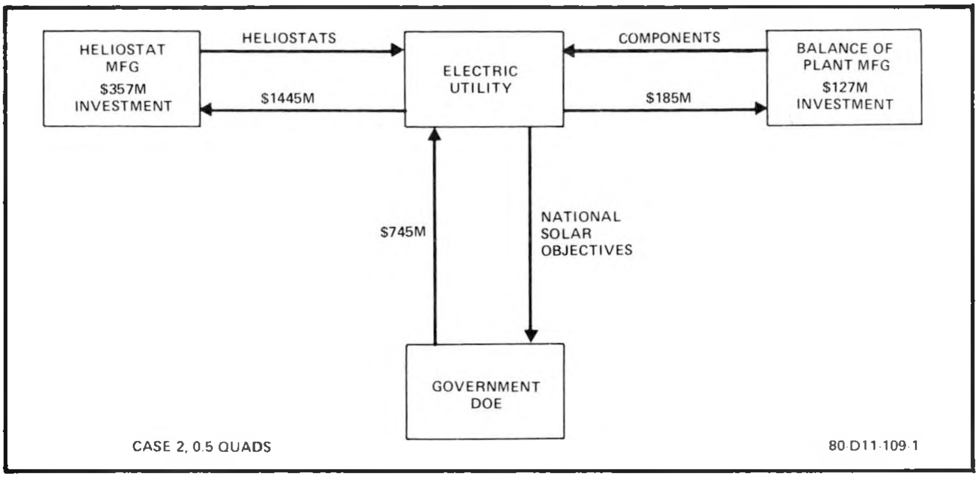


Figure 3. Government Incentives
Utility/Government Cooperative

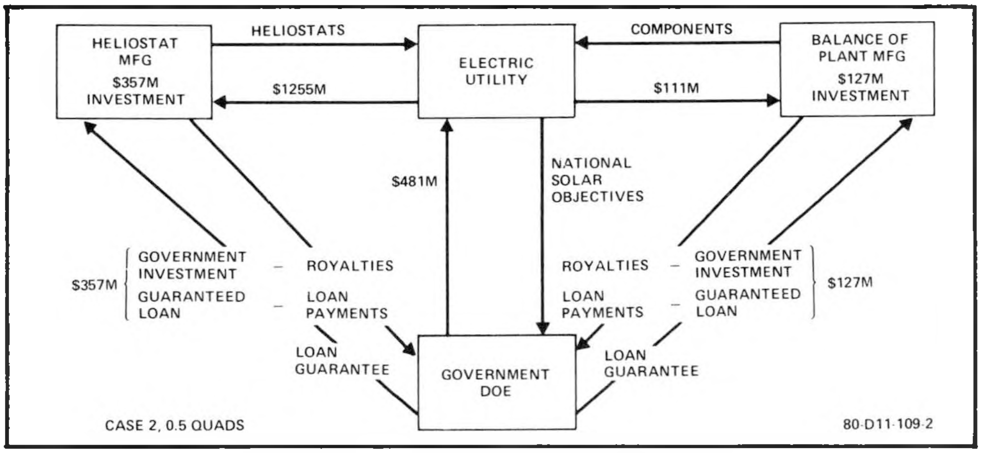


Figure 4. Government Incentives
Manufacturer/Utility/Government Cooperative

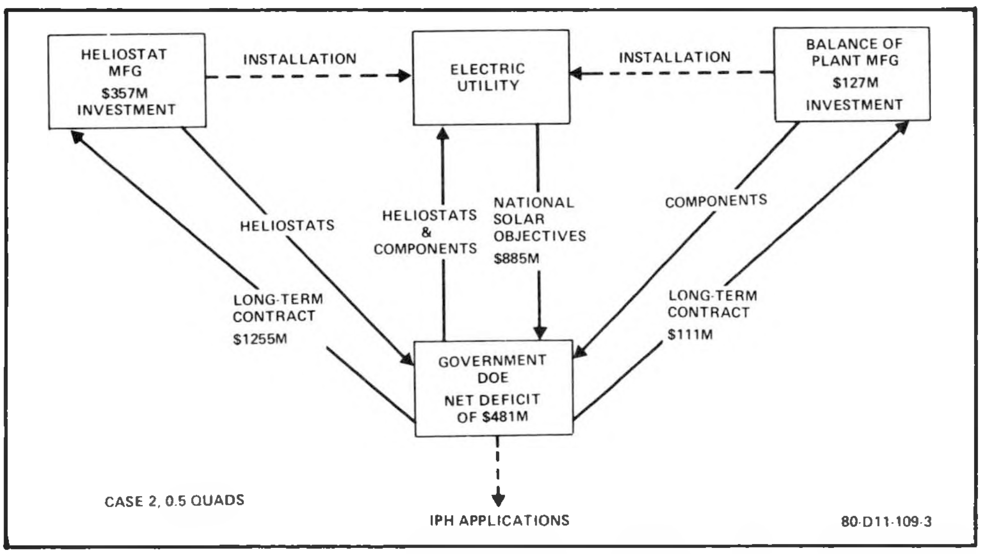


Figure 5. Government Incentives
Manufacturer/Government Cooperative

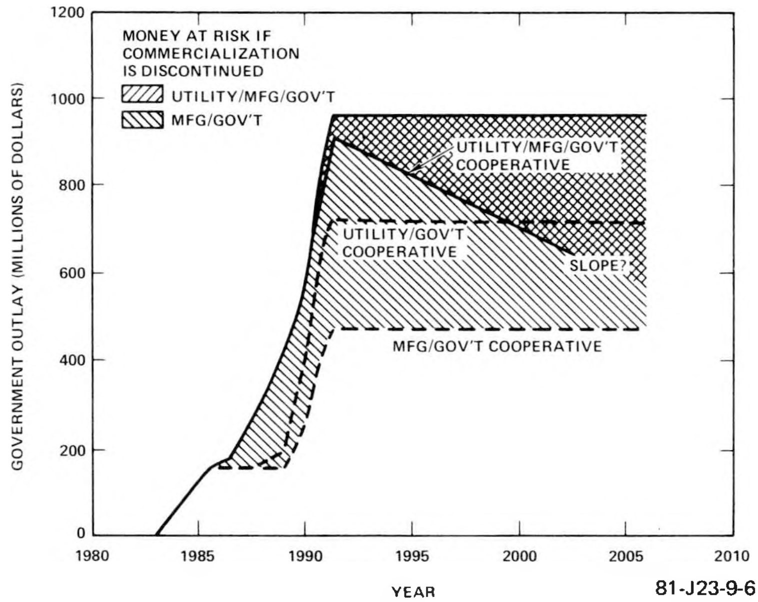


Figure 6. Government Cash Flow (1980 $)

TABLE 1

GOVERNMENT INCENTIVES FOR FOUR SCENARIOS

	Case			
	1	2	3	4
Energy Level by Year 2000	0.1 quads	0.5 quads	0.5 quads	1.0 quads
Year of Commercial Viability	1996	1992	1990	1991
Total Plant Subsidy	$408M	$481M	$550M	$332M
Heliostat Manufacturing Investment	$253M	$357M	$205M	$330M
Balance-of-Plant Manufacturing Investment	$55M	$127M	$88M	$161M
Total Government Incentives*	$546M	$745M	$790M	$735M

*This total represents the utility/government cooperative using the short-term amortization of manufacturing facilities before the year of commercial viability

ASSUMPTIONS: General inflation at 8%
Gas escalation at 10%
Cost of gas = $2.50/10^6 Btu

Follow-on Studies

Since the study contract was completed, we have had a change of president and a reorientation of government's role in commercialization. We have, since then, conducted additional studies (funded in-house) to determine alternative methods for financing the uneconomic portion of early commercial plants.

Basically, there are two barriers preventing commercialization by the private sector. First, the estimated cost of the first plant exceeds its value to the utility at this time due to the high cost of heliostats, which are not currently in high-volume mass production. Secondly, cost and performance uncertainties exist on key components. Because current cost estimates are based upon conceptual designs only, a cost uncertainty of as much as 50% may exist. Also, there are performance uncertainties in any new system, particularly if key components have never been built and tested in the given size and temperature range.

Figure 7 shows a cost of \$254 million for a 100-MWe plant with 6 hours of storage. A heliostat cost of \$175/m^2 was assumed. We have added a 50% cost uncertainty for a first-of-a-kind plant. History has typically shown a cost growth as one proceeds through preliminary and final design and construction for a first-of-a-kind plant. In addition to the plant cost, the plant value is shown for various assumptions for fuel-avoided costs. The current high cost of capital was considered in evaluating plant value. Using a current fuel-avoided cost of \$7.50/10^6 Btu, the estimated plant cost is covered, but there is a \$108 million shortfall when the 50% cost uncertainty is included. The 12¢/kWh was a midpoint-type value that utilities indicated a willingness to pay for a solar central receiver plant. Here, the shortfall is \$193 million with and \$82 million without the cost uncertainty.

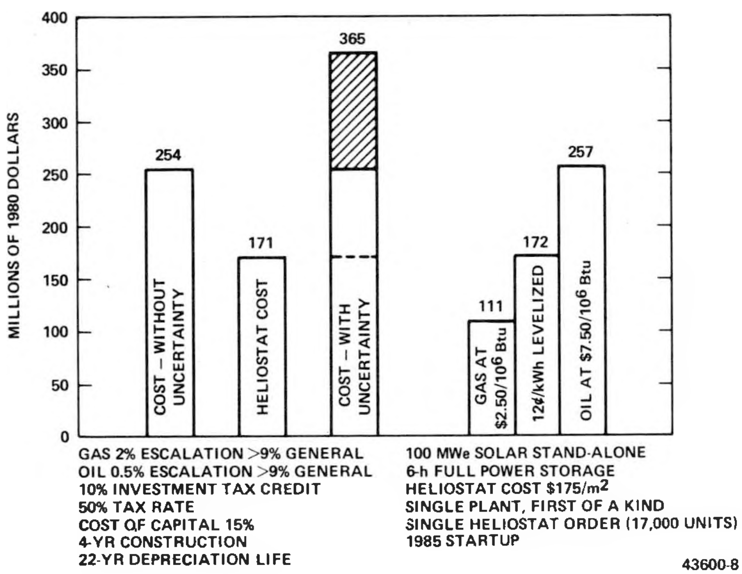


Figure 7. Plant Value is 30% to 70% of Plant Cost (includes 50% cost uncertainty)

Various approaches were taken to cover the uneconomic portion. We queried utilities as to the types of financial incentives they felt would be useful. We have separated these into state and federal legislative actions and Public Utility Commission ratemaking policies.

State and Federal Legislative Action

The potential solutions at the federal and state level considered were:

1) The DOE repowering program
2) Increased investment tax credits
3) Accelerated depreciation
4) Third-party ventures
5) Untaxed dividend reinvestment into renewable energy sources.

The DOE repowering program has already been discussed under the contract portion. We have assessed the other approaches as follows.

Tax incentives such as investment tax credits and accelerated depreciation effectively reduce the cost of electrical production of a power plant. Figure 8 shows the effect of the investment tax credit. At the standard tax credit of 10%, there was an $82-million deficit in plant value at a levelized 12¢/kWh. If the 15% solar tax credit (25% total) is extended, the deficit is reduced to $42 million. A 37% combined solar and general tax credit would make it possible to compete now at a levelized 12¢/kWh. A similar effect can be shown for accelerated depreciation. The case shown in Figure 9 is coupled with a 25% tax credit. With a 6-8 year depreciation schedule, the disallowance cost is reduced to zero. Reagan's new tax program allows for a 5-year depreciation schedule. Going from a 22-year depreciation to a 5-year depreciation decreases the effective cost of the plant by approximately $65 million. One major problem with this solution is that many utilities are not in a position to take advantage of these tax advantages because much of their income is already sheltered, or else the Public Utility Commission (PUC) requires the tax savings to pass directly to the ratepayers, thereby negating the attractiveness of the tax cuts. However, these restrictions may be overcome by allowing increased carry-forward time periods for credits and/or lobbying for PUC ruling changes.

Third-party ventures provide an attractive alternative to take advantage of tax credits and accelerated depreciation schedules. In addition, the Public Utility Regulatory Policy Act (PURPA) requires utilities to pay fuel-avoided costs that can be as high as 7.5¢/kWh. Figure 10 illustrates the capital requirements for a third-party venture if a 75% debt ratio (at a 15% rate of interest) can be obtained and the 15% solar tax credit is available (25% total). Even with a 50% cost uncertainty, a 34% rate of return is obtainable. For early central receiver plants, this is one of the more promising solutions and one consistent with current administration policies, which encourage private industry to take the lead in development of alternate energy sources. It also puts risk-taking in the hands of venture capitalists who are accustomed to dealing with performance and cost risks. One of the best ways government could encourage early commercialization is to extend the solar tax credit beyond December 31, 1985, to allow more lead time for implementation of early commercial plants.

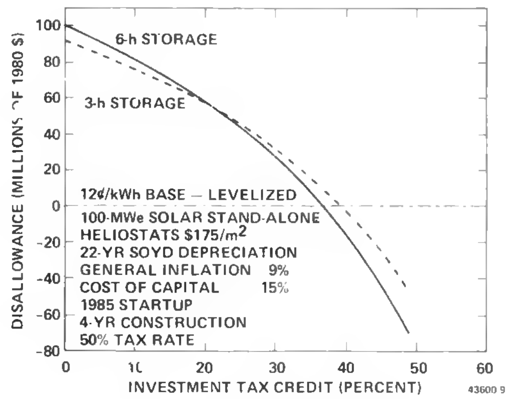


Figure 8. Effect of Investment Tax Credit on Disallowed Portion of Solar Plant

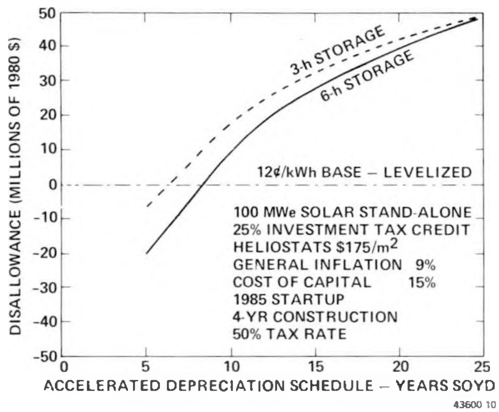


Figure 9. Effect of Depreciation Schedule on Disallowed Portion of Solar Plant

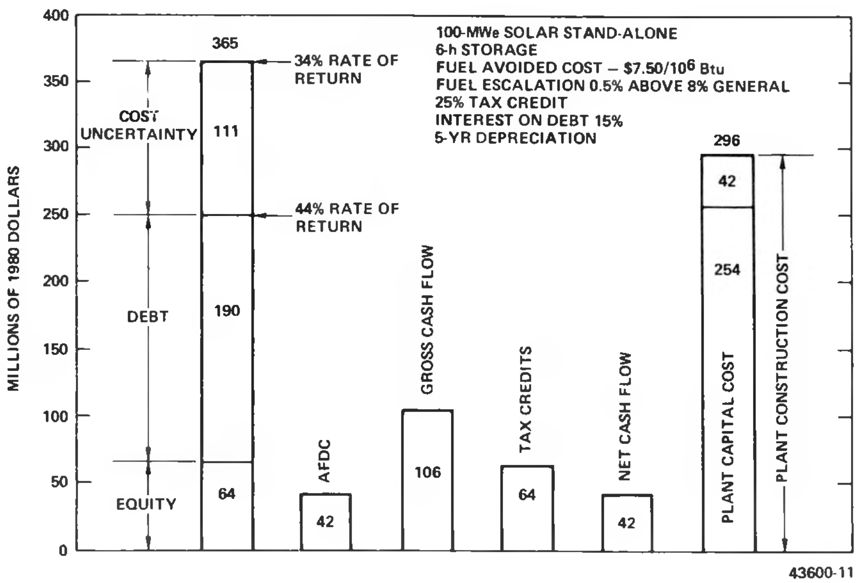


Figure 10. Third-Party Venture-Financial Analysis

The final suggestion was reinvestment of untaxed dividends into alternative energy sources as shown in Figure 11. The effect of using untaxed dividends is to reduce the cost of capital. At a 50% tax rate, the required rate of return is reduced by one-half. Assuming a 15% cost of capital is equivalent to a 50% debt position and a 20% rate of return on interest and common stock, the effect of reinvestment of nontaxed dividends would be to effectively reduce the cost of capital to 10%. Reducing the cost of capital from 15% to 10% results in an $80 million increase in plant value. At this time, no actual legislative tax proposal along this line has been made.

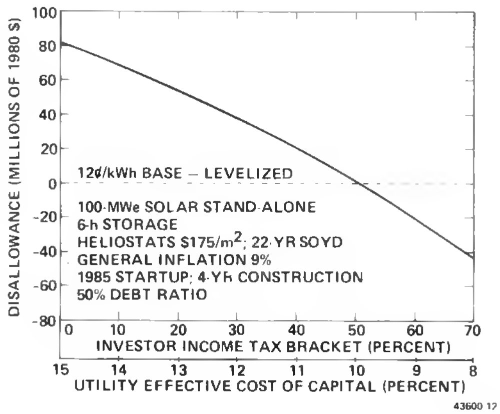


Figure 11. Allow Untaxed Dividends to be Reinvested into Renewable Energy Resources

Public Utility Commission Ratemaking Policies

Since utilities are a regulated industry, their investments are strongly influenced by PUC policies. PUC regulations vary from state to state and, therefore, the approach to funding early commercial plants will differ. Early commercial plants, which are really demonstration plants, fall in a very awkward position as far as funding. Early R&D work is considered a legitimate expensing item and written off within the year in which it occurs. Demonstration plants, however, are expected to be justified on an economic basis even though, as a first-of-a-kind plant, they do not have mature-commercial-plant costs.

Again, several proposals that a PUC could use in encouraging renewable energy sources have been made:

1) Allow new power plants to be justified on the basis of levelized costs.
2) Treat unallowed costs as R&D expensing.
3) Allow a higher rate of return on solar technologies.
4) Allow utilities to form subsidiaries.
5) Include construction costs in the rate base.
6) Support, as an agency, any consortium effort to put together a single "large" block order to reduce heliostat costs.

Figure 12 illustrates the effect of determining plant value on the basis of fuel-avoided cost for various levelized time periods. In the previous analysis, plant worth was based on a 30-year levelized period. For capital-intensive investments such as a solar plant, this results in today's ratepayers paying a cost penalty in return for ratepayers 15 to 30 years in the future receiving an energy cost reduction. It also requires the PUC to make judgments between alternative energy sources based on 30-year cost projections. The aversion to putting the ratepayer at risk results in a tendency to make very conservative 30-year projections, as they must convince today's ratepayer that the current rate increase is to his ultimate benefit. The 12¢/kWh is equivalent to an 11-year levelization of fuel-avoided cost and results in a plant value of $172 million; a 30-year levelization results in an equivalent levelized energy cost of 18¢/kWh and a plant value of $257 million.

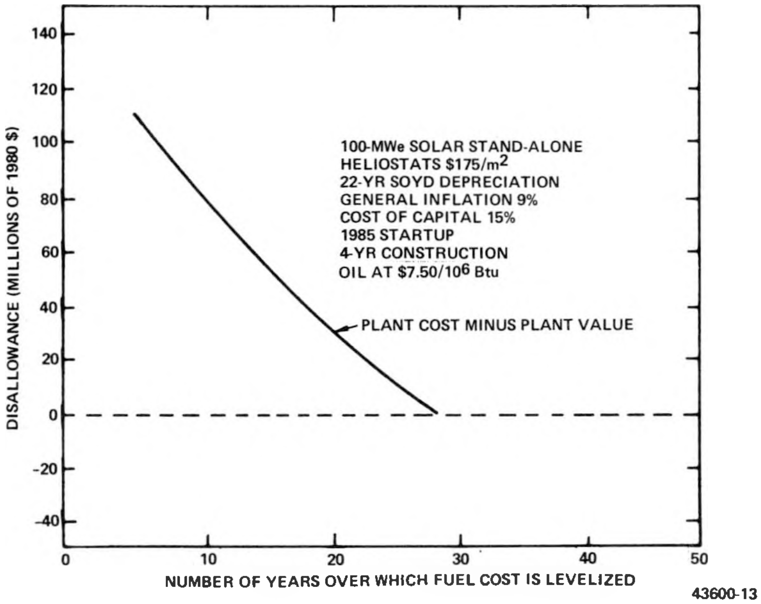


Figure 12. Effect of Levelizing Years on Solar Plant Disallowance

Another alternative is for the PUC to treat the disallowed portion of early commercial plants as an R&D expense. This does represent a direct increase to the ratepayer but, in some sense, demonstration plants are an R&D item. As a market matures, this investment in advancing technology represents a potential cost saving to the ratepayer. Table 2 shows the unallowed costs as a function of the PUC basis for plant value. This would represent a significant expense to which a PUC would be unlikely to agree. Alternatives might be to agree to expense the preliminary design effort, to allow a plant value based on a fuel-avoided cost of $\$7.50/10^6$ Btu, and to expense a certain percent (but less than 100%) of any cost growth. This would represent a shared risk between the ratepayer and the investor.

Many utilities expressed concern that, for a regulated industry, there is very little incentive to invest in a high-risk solar plant. Normally, a higher rate of return is needed to justify higher risks. A higher rate of return, however, reduces the plant value. It will not increase economic attractiveness, so it is not a solution unless it is attached to some other alternative that will cover the disallowed portion, In addition, reservations to this approach indicate that a "higher rate of return" awarded by the PUC does not

TABLE 2

TREAT UNALLOWED COSTS AS R&D EXPENSING

Plant Value Basis	R&D Expense	
	Minimum	Maximum*
Gas at $\$2.50/10^6$ Btu	$143M	$254M
Elec. at 12¢/kWh	$82M	$193M
Oil at $\$7.50/10^6$ Btu	0	$108M

*Includes 50% cost uncertainty

always result in the investor's retaining that rate of return. One solution is forming a subsidiary that can retain a higher rate of return and is in a better position to take advantage of tax incentives. A subsidiary would have cash flows similar to a third-party venture, which was shown in Figure 10.

Allowing construction costs into the rate base was another suggestion. The main purpose of this approach is to put utilities into a better cash flow situation so that they can make capital investments into renewable energy sources. The effect on plant value would vary from state to state as there are considerable differences in how construction funds are treated by the PUCs of the various states.

Heliostat costs are the largest controlling factor on total plant costs. For early commercial plants, costs are high because of low volume and short-term amortization costs. Our studies show that if a consortium could be formed for building multiple plants, heliostat costs could be reduced. There are many problems associated with forming a consortium and maintaining competition between heliostat manufacturers, problems which are presently being considered by Battelle.

Conclusions

At this point, there is no single solution to make early commercial plants economically competitive. The DOE repowering program would go far toward achieving commercialization goals. At this time, the best alternative to the DOE program appears to be retention of favorable tax incentives, use of third-party ventures or subsidiaries to take advantage of those tax incentives, and a favorable PUC attitude toward developing renewable energy sources.

715-C.18/sjh/nth

THIRD PARTY FINANCING OF CENTRAL RECEIVER REPOWERING PROJECTS

Prem Munjal
JoAnn Walter
Prem Mathur
THE AEROSPACE CORPORATION

Introduction

DOE is developing solar thermal technology for utility and industrial applications that can significantly reduce the nation's dependence on imported oil. Progress has been made in solar central receiver system development that shows the potential technical viability and economic attractiveness of solar thermal energy systems. These studies and additional feedback from industry also show that, like any other new technology, the cost of a one-of-a-kind first plant is high and effective technology transfer to utility and industry will not take place without additional DOE efforts. This study investigates an innovative third party financing approach for the first solar thermal repowering plants that may reduce the need for direct DOE cost sharing during the critical early application of central receiver technology by industry.

Third Party Financing Approach

Third party refers to a corporation, partnership, or a joint venture that can take advantage of existing financial incentives. As owner of a solar thermal system, a utility itself cannot use the federal solar tax credit. In addition, the Tax Act of 1981 has assigned a longer depreciation class life for a utility property as compared to an equivalent business and industrial property. Also, unlike a utility owned project, a third party venture does not have the drawbacks of direct regulation. As long as the utility ownership is less than 50%, an initial repowering project can take advantage of various tax credits, accelerated depreciation and other benefits of an independent unregulated power producer. A utility may supply a portion of the required capital as equity money to a majority share partner or can offer a large loan for a leverage lease arrangement. A utility may also do the necessary operation and maintenance (O&M) of the central receiver and provide the project site. Similarly, a system supplier, e.g., heliostat manufacturer, may provide the necessary loan, may become a partner with the third party, or both. A third party business may be established for the sole purpose of producing central receiver generated electricity. A third party can be a joint venture between: (a) investors group, service company, and/or utility; (b) system manufacturer, end user, and/or contractor; (c) profit-making business, utility, and/or developer; and (d) any combination of the above, where one of the parties can take full advantage of the various state and federal tax benefits that are offered by a central receiver project. The primary requirement of a successful third party structure is that it must have an adequate tax liability, which makes full use of various state and federal tax benefits. Figure 1 presents one of the many possible structures of a third party venture.

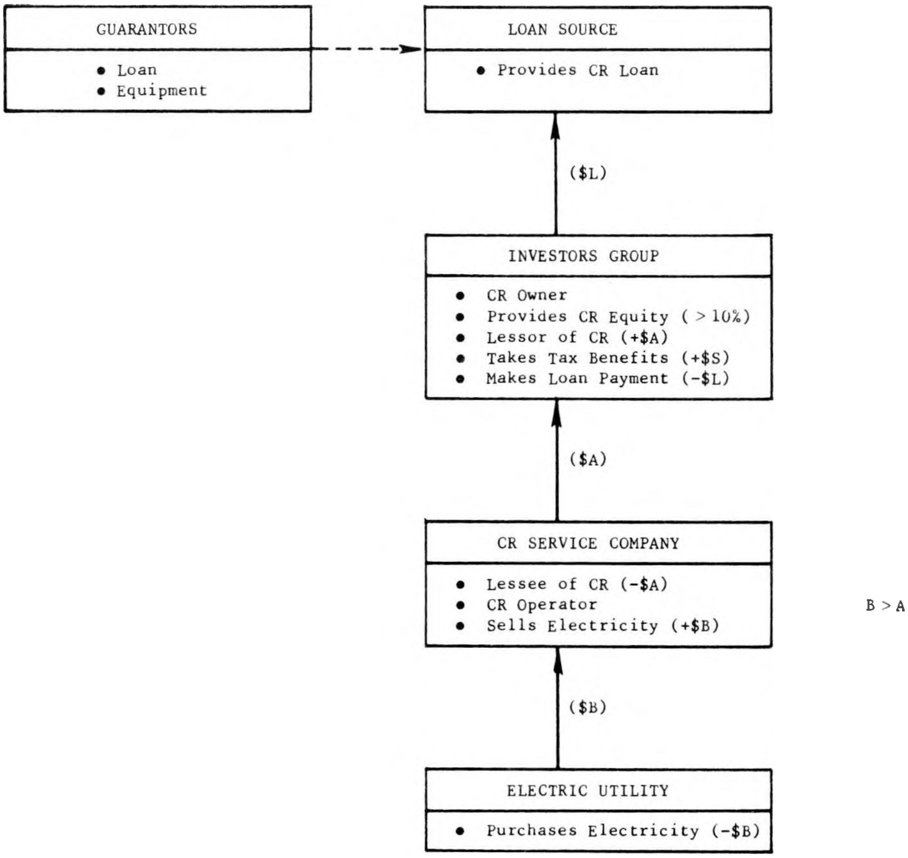


Figure 1. Possible Structure of a Third Party Central Receiver (CR) Venture

Available Financial Incentives

The recent changes in various state and federal laws are aimed at promoting the renewable energy sources, such as solar thermal central receiver technology. A utility is now required to purchase central receiver generated electricity at avoided cost rates. In addition, there are substantial tax credits and depreciation allowances provided by many state and federal laws to offset high pre-mass production heliostat costs. These tax benefits can make an initial repowering project an attractive investment in today's market. As the manufacturing of heliostats moves into mass production, there should be substantial reductions in the central receiver plant costs. These reductions will make the future production of central receiver electricity and industrial process heat economically attractive without the help of various financial incentives. Some of the available incentives applicable to a first repowering project are summarized below.

Guaranteed Market

Section 210 of the Public Utility Regulatory Policy Act (PURPA), is aimed at encouraging development of alternate energy sources. It gives the Federal Energy Regulatory Commission (FERC) certain powers to encourage the growth of small power production and cogeneration to displace conventional electric power generation. Solar thermal central receiver technology is one of the alternate energy sources contemplated by Congress in enacting PURPA. The protections and incentives offered by PURPA apply to the central receiver qualifying facilities, called QF's that are under 80 MWe (no limit for cogeneration). Utilities must purchase all usable electric energy made available by a QF at a rate that reflects the utilities "incremental costs".

Thus, QF's will receive maximum benefits without causing increases in electric rates for other consumers, at least increases that they would not otherwise experience. When generating electricity, a utility brings its least expensive source on-line first, and its most expensive source last (frequently an older oil-fired plant). The incremental cost of bringing the last, most expensive source on-line is called the "marginal" or "avoided" cost. A utility is required to pay for central receiver electricity at an "avoided cost" rate that will rise with increases in the cost of oil. For example, Pacific Gas and Electric currently (1981) assigns a price for purchasing renewable energy at 81 mills/kWh on-peak and 67 mills/kWh off-peak. The price paid for solar electricity varies with the utility so that it may be advantageous for a third party to sell electricity to a utility some distance from the plant site at a higher price. In this case, the QF is paid the avoided costs of the second utility less any transmission or "wheeling" expenses the first utility incurs.

A QF is also exempt from filing utility reports with the Federal Securities and Exchange Commission and is free from state and federal regulation as utilities.

Federal Tax Benefits

Many federal tax benefits are also available to third party investors of central receiver technology. These tax benefits include the 10% federal investment tax credit and an additional 15% Solar Energy Tax Credit provided by the Windfall Profits Tax Act of 1980. This energy credit applies to all solar hardware except for the new transmission lines that may be required to interconnect with the utility grid. This credit has no limit, but is scheduled to expire December 31, 1985. Utility ownership of a central receiver technology is not eligible for this energy tax credit. Investment tax credit can be carried backwards and forwards. The Economic Recovery Tax Act of 1981 has increased the carry forward period from 7 to 15 years.

In addition to these tax credits, the new Tax Act of 1981 establishes a new depreciation system, known as the Accelerated Cost Recovery System (ACRS). Third party ownership of solar central receiver property would be qualified for a 5-year class property for depreciation. Compared to this, a utility ownership is allowed to depreciate the same plant in 10 to 15 years.

Recognizing that some businesses and utilities may not be able to completely use the above mentioned tax credits and depreciation, the Act provides for their transfer to corporations that could use them. To facilitate the transfer of these benefits, the new Tax Act establishes safe harbor rules that, if met, characterize a transaction as a lease for allowing the various tax credits and deductions to the nominal lessor. The qualifying requirement for this leveraged lease arrangement is that the property must be leased within three months after its acquisition and at all times during the term of the lease the lessor must have a minimum, "at-risk" investment of not less than 10% of the adjusted basis of the property. There is no requirement that the lessor derive a before-tax profit or have a positive cash flow, or that the property be usable by someone other than the lessee.

State Tax Benefits

Many states also provide additional state tax credits and depreciation benefits to renewable energy sources. Some states also exempt both property and sales taxes. In California, a central receiver project is eligible for a 25% state energy tax credit in addition to the federal tax credits. This credit has no limit and is not reduced by any federal tax credit. These credits apply to all components of the solar energy collection system, energy storage and power conditioning equipment. However, the tax savings produced by the state credit are reduced since these are treated as federal taxable income. Even so, the state tax credit is a valuable incentive which may be carried forward to future years. Again, Calfornia State law permits depreciation in 1, 3 or 5 years in lieu of the 25% state tax credits. Another option is to claim the state credit and depreciate the remaining cost above the amount of the credit within three years using the double declining balance.

In Arizona, the state tax credit is 35% of the cost of the solar energy system through 1983. Thereafter, the percentage decreases 5% per year until the credit expires on December 31, 1989. Excess credit may be carried forward for not more than 3 years. In lieu of claiming a credit, one can amortize solar equipments over a period of 3 years. In addition, the state exempts solar energy devices from property taxation through December 31, 1989. Also the solar system is exempt from the Business Sales and Excise Taxes. However, there are a few states that do not offer attractive credits for solar devices.

Third Party Economics of First Central Receiver Repowering Plant

Like most new technologies, investment in a first central receiver repowering plant may not yield the desired returns that are commensurate with its associated possible risks. However, economic assessments of utility and industrial applications of central receiver technology show potential future economic viability of these systems. While solar system costs should decline through mass production, fuel costs will increase with time.

The central receiver strategy to transfer technology to industry include reducing technical and financial risks through operation of the Barstow plant to permit industrial scale-up and operation by repowering or solar retrofit of existing utility and industrial oil or gas fired plants.

Site specific conceptual designs conducted by DOE through user-supplier industry participation show that the technology is acceptable to industry but additional technical and cost sharing will be required for the initial repowering plants in order to transfer central receiver technology to utility and industry. Once manufacturers have sufficiently developed their product to provide fixed price quotes within an acceptable price range and performance warranty, then normal private ownership of central receiver plants should become possible.

Figure 2 represents a simplified account of various cash flows into and out of the central receiver investments, shown by appropriate arrows. The future revenues from the sale of electric power are net of O&M expenses and have a present value representing X% of investment cost when discounted at the project's return rate. Similarly, benefits from various tax credits and depreciation, and costs of state and federal income tax payments on sales of electric power are given with their respective present values of Y% and Z% of investment cost. For the first and near term central receiver plants, the percent of cost covered defined as (X+Y-Z) is less than 100%.

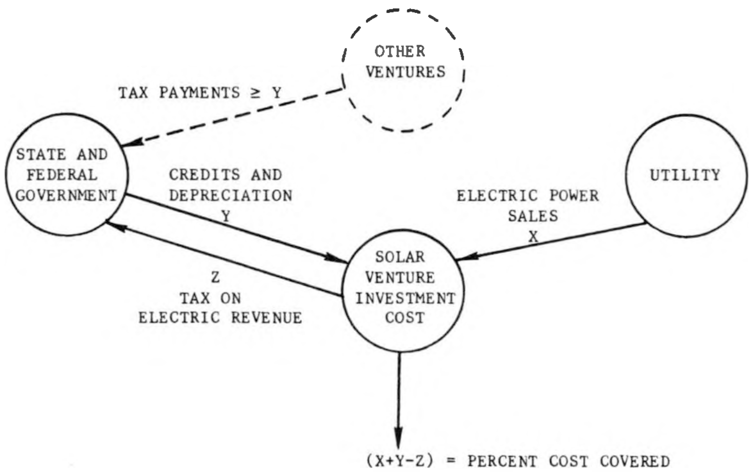


Figure 2. Cash Flows of Third Party Ownership

The central receiver technology R&D activities can increase the electric value benefit through improved plant designs and subsystem efficiencies, increased system operating life, and reduced O&M and system costs. These activities and the mass production of heliostats should eventually bring the electric revenue benefit (X) to equal the investment cost.

This would also result in increased income tax payments (Z), which should eventually approach or exceed the tax benefits (Y). Thus, the government will begin to receive payoff from its renewable solar energy development programs as revenues from income tax payments (Z) increase over solar tax benefits (Y). In addition, an investment in solar development would have a significant impact on displacing critical fuels to reduce the nation's dependence on imported oil and American business would be less vulnerable to any interruption in foreign oil supplies.

Case History of a Typical Utility Repowering Plant

The Arizona Public Service (APS) Utility Saguaro Plant No. 1 is a candidate for central receiver repowering project for which specific conceptual designs have been developed. This plant site is located 41 miles north of Tucson, Arizona. APS in association with Martin Marietta Corporation completed its conceptual design using molten salt as the receiver heat transport fluid (Figure 3). Four hours of thermal storage are provided by an internally-insulated hot salt tank and an externally-insulated cold salt tank. When solar energy is available, salt is pumped from the cold salt tank at 530°F to the solar receiver where it is heated to about 1050°F. The heated salt returns to the hot salt tank where it is pumped to the heat exchanger string to generate superheated steam for the turbine operation at 1000°F, 1450 psia resulting in a net solar electric power output of 253,000 MWHe/year. APS costs for this central receiver repowering project were estimated in (1985$) for a plant start in 1985. The total cost estimated for the system was $\$273.7 \times 10^6$. The capital cost was $\$238.1 \times 10^6$ with a heliostat (10,500 @ 49 m^2 each) cost of $\$330/m^2$ (which is $\$230/m^2$ in 1981$). Expenses due to annual O&M totaled $\$1.76 \times 10^6$. A 10-year operating plant life was conservatively assumed to account for the risk of a "first-of-a-kind" plant.

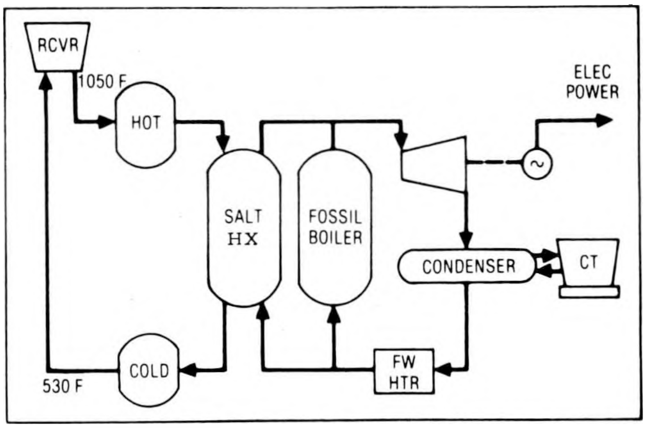


Figure 3. APS Saguaro Solar Repowering Project

Using Arizona and federal corporate tax laws and assuming an electric sale price of 75 mills/kWh with a net escalation rate of 5% and a general inflation rate of 7%, the economics of this initial plant was evaluated using a 20% rate of return. Figure 4 shows the effect of heliostat cost reduction on the percent cost covered under the above mentioned assumptions. The base case with a heliostat cost of $\$330/m^2$ only recovers about 93% of investment cost (X,Y,Z in Figure 2 are respectively 44, 71, and 22 percent). In order to breakeven, that is 100% cost covered, a $\$190/m^2$ cost would be required. This indicates that additional technical and financial help to the third party would be required for the initial repowering plants. However, a 25% government cost share in capital equipments reduces the otherwise available tax benefits (Y) by 25%. Thus, government cost sharing would be more effective if applied to engineering and other non-capital items that tend to reduce the technical risks and uncertainties. An increase in the electric price to a 100 mills/kWh electric sales price will also result in a breakeven economics. Another possible approach to alleviate the problem of high cost of initial repowering plants, and to reduce government cost sharing is to employ innovative financing in the third party approach as discussed in the next section.

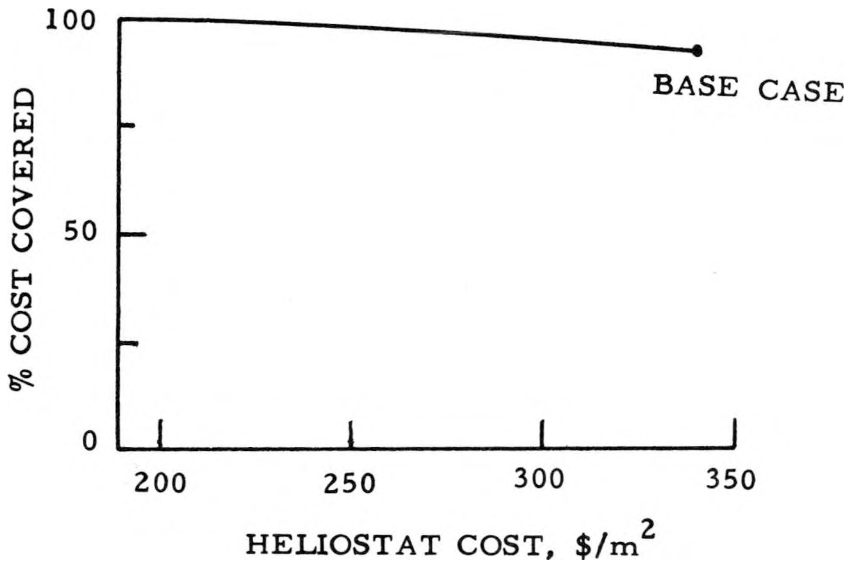


Figure 4. Effect of Heliostat Cost Reduction on Percent Cost Covered

The above analysis assumed the availability of both federal and state solar energy tax credits. After the expiration of these tax credits, the remaining tax benefit (Y) would be reduced to 46% (versus 71% with energy credits), which must be recovered through the increased value of net after-tax electric benefits (X-Z) as mentioned earlier in Figure 2. The breakeven economics for this future scenario would require a 135 mills/kWh electric price and a $200/m^2 heliostat cost (1985$). In this case the income tax payments (Z = 53%) to government exceed the derived tax benefits (Y = 46%) resulting in a net government payoff of about 7% of the system investment. Since these figures are based upon a discount rate of 20% and income tax payments are more heavily influenced by the discount rate than the tax benefits, the undiscounted payoff to government would be about 80% of system cost.

Innovative Third Party Financing

As discussed earlier, the major benefits from an initial central receiver third party ownership are the advantages of various tax benefits. The primary requirement of a successful central receiver third party financing is that it must have adequate tax liability to derive the necessary full benefits of various tax credits and deductions. The magnitude of these benefits can be further increased if the investment is leveraged by borrowing a substantial fraction of the required capital whose after-tax debt cost is lower than the after-tax rate of return expected by the third party. Arrangements of this sort were anticipated in the drafting of Economic Recovery Act of 1981 and PURPA and are encouraged by these Acts.

Figure 5 illustrates the structure of one possible third-party financing arrangement for the example case that could be an attractive investment in the construction of a repowering project, at current high system costs. The central element of the structure is the source of the equity funding -- a corporation or group of corporations, a partnership of individual investors, or some combination of these, with substantial tax liabilities and a concomitant need for increased tax credits and deductions that have become possible with leveraging. In the example considered here, an optimum leverage was obtained by 50% of plant cost loan and with 55% investor's equity which includes a 5% reserve fund. Cash from this reserve account is released, as required, in order to eliminate the negative before-tax cash flows that would otherwise occur during the early years of plant operation, before the revenue stream from electrical power sales has grown large enough to cover the costs of amortizing the loan.

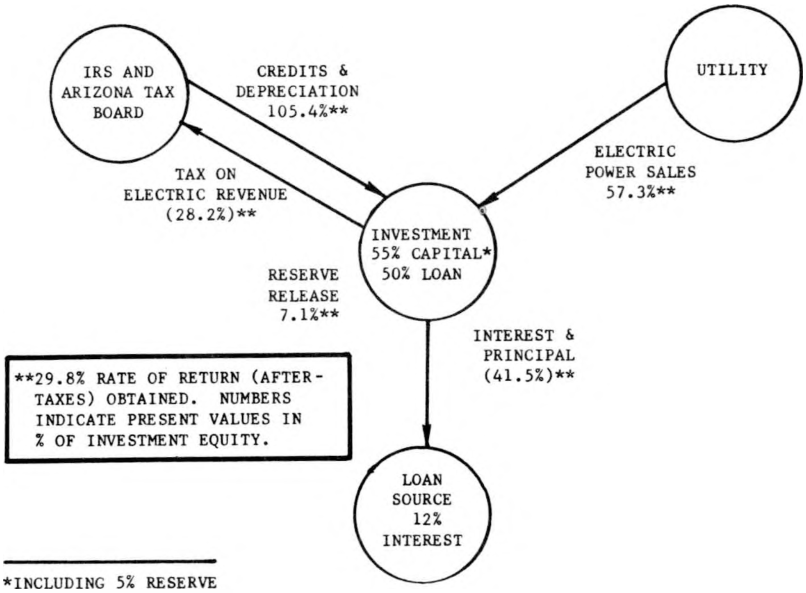


Figure 5. Leveraging to Maximize Benefits for a Third Party Venture

It is assumed in the example that the interest charged on the debt portion of the investment is 12% and that the reserve funds earn interest at this rate while they remain on deposit. This interest rate may appear somewhat low in the light of current (1981) pathologically high rates, but it is expected that conditions will have stabilized (general inflation assumed at 7%) by the time such a plant would be constructed. Even if this does not occur, it is considered likely that debt financing at a reasonable interest rate may be provided by an organization with a strong vested interest in the central receiver technology, e.g., one of the large aerospace companies that have investments in the industry. Thus, to a heliostat supplier's parent corporation that has most to gain from the third party venture, a moderate interest loan may well appear to be a relatively low-cost way of ensuring itself a favorable market position. Such arrangements are not uncommon in the private sector (e.g., automobile industry) when access to a large market is desired by a major supplier. Also, since institutional lenders are not risk takers, the project size is important and the return these lenders receive on their debt funds depends on the credit backing and guarantees of these parties arranging the third party venture. Small companies are unlikely to offer this credit support. Large companies who have a direct stake in the central receiver venture and who have a basis for believing that their product is incorrectly perceived may take a risk position in various forms of extended warranties, debt and equity contributions to a third party venture. Again, the risks and uncertainties associated with the application of national security related new technology for projects of the magnitude of central receiver are often shared with the government.

Once the capital has been committed, construction funds are released to the A&E from a systems company responsible for the plant design, to the general contractor responsible for construction, and through him, to the subcontractors and suppliers of components and subsystems. After the system has been constructed and is in operation, the electric power output is delivered to the utility system serving the region in accordance with a long-term purchase agreement. In this example, all the other assumptions including plant costs, its operating life and costs, and electric price and its escalation rate are the same as given earlier. As described before in Figure 2, the arrows in Figure 5 show cash flows into or out of the investment. The percentages calculated indicate the present values in percent of investment equity. Sale of electric power and reserve account came, respectively, to the revenues of 57.3% and 7.1% of investment equity. Credits and depreciation from Internal Revenue Service and Arizona tax board added to 105.6%. The benefits of the three tax credits can be realized in the year in which money is expended. Benefits derived from depreciation and other tax deductions, on the other hand, are spread over a number of years. Income tax payments on electric power revenues are 28.2%. Similarly, after-tax interest and principal repayments for the loan add up to about 41.5%. Both the income tax and the loan payments are negative cash flows (out of the system), and thus the arrows point away and a parenthesis is around the 28.1% and 41.5%. By adding the percentages of each component, noting the appropriate sign, 100% of the investment is recovered with an after-tax rate of return of 29.8%. Thus, the combined effect of all these sources of income and costs is to produce a net after-tax return on equity of 29.8%, -- a sufficiently handsome rate of return to justify a moderate degree of risk. The analysis, therefore, suggests that if the risk can indeed be kept moderate, early private-sector construction of the first utility-scale central receiver plant is a real possibility, even at system prices that are currently estimated by design contractors.

The above concept of third party financing is currently being pursued by LUZ International Ltd. for solar thermal process steam to textile companies and by Wind Farms and U.S. Wind Power for wind generated electric power to various utilities. Figure 6 shows the cumulative cash flow plots of before-tax, after-tax, and after-tax net present values as a function of time when the plant becomes operational, where cash flows are presented in terms of fraction of investment equity. The after-tax curve shows that approximately 90% of the investment equity is recovered in the first year with an early payback period of about 1.5 years. After 10 years, 140% of

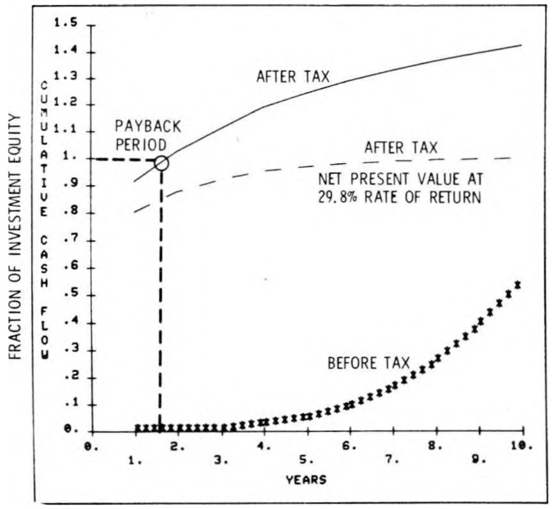


Figure 6. Cumulative Cash Flow vs. Time

the investment is recovered and this yields a 29.8% return on equity as shown on the net present value curve. The before-tax cash flow recovers only 50% of equity, indicating that tax benefits play a major role in the recovery of investment for the initial central receiver plant. It should also be noted that through proper leverage, negative cash flows were avoided for both before and after-tax situations by using The Aerospace Corporation third party simulation model. Also, the above analysis assumed the availability and full use of both state and federal solar energy tax credits. Without these tax credits, even an innovative financing of third party ownership will not yield the necessary return on investment and both higher (~105 mills/kWh, 1985$) electric price and lower (~$200/m^2, 1985$) heliostat cost would be needed to approach the above mentioned return rate.

Sensitivity Analysis

The above return rates are based upon the various assumptions and conditions that may be considered somewhat ideal by some companies and investors of solar central receiver, consequently, a sensitivity analysis on the above mentioned base case was performed and is shown in Figure 7. As mentioned earlier, this base case assumed no direct goverment cost sharing. This analysis was carried out to quantify the various risks and uncertainties of incurring higher system costs, O&M, loan rates and zero electric escalation. Also, benefits due to longer system life and higher electric price were analyzed. In addition, the effect of a New Mexico plant location where other parameters are kept unchanged, showed a significant lower return that is primarily due to the absence of any state energy credit. This indicates that third party financing for the present example of first plant cannot work without adequate state tax credits. The effect of a California location did not appreciably lower the rate of return, since California also offers very attractive state energy tax credit. The analysis also showed significantly lower returns if only 75% of tax credits could be utilized, indicating that tax benefits are not helpful unless the third party has an adequate tax liability.

SCENARIO	RETURN ON INVESTMENT
BASE CASE	29.8%
DOUBLE O&M	26.8%
LIFE 15 VS. 10 YEARS	42.4%
LIFE 20 VS. 10 YEARS	48.7%
LOAN RATE 15% VS. 12%	26.0%
NEW MEXICO VS. ARIZONA LOCATION	8.4%
CALIFORNIA VS. ARIZONA LOCATION	26.8%
75% USE OF TAX CREDITS VS. 100%	14.7%
ZERO ELECTRIC POWER ESCALATION VS. 5%	22.9%
25% INCREASE IN SYSTEM COST	19.9%
ELECTRIC POWER SALES PRICE 100 VS. 75 MILLS/kWh	41.7%

Figure 7. Sensitivity Analysis of Base Case Assumptions

General Observations

Third party ownership with proper leverage financing represents a possible solution approach for the initial repowering plants for which pre-mass production heliostat costs are high. As shown by a case example, a substantial portion of investment equity can be recovered in the first few years of plant operation through various existing tax benefits. Also, good future years cash flows appear possible due to the requirement that utility purchase central receiver generated electricity at the high avoided cost rates. However, success of third party financing is highly dependent on its ability to take full advantage of various federal and state tax benefits. To do this, a third party group must have an adequate federal and state tax liability. Also, to cover the negative cash flow in the early years, a cash reserve may be required. Furthermore, in order to attract equity and necessary loan from the private sector for the early central receiver ventures, both a loan guarantee and an equipment performance warranty will probably be required.

Thus, third party financing of a repowering project with appropriate government risk sharing can play a significant role in bringing heliostat manufacturing to the mass production phase before state and federal energy credits are phased out.

In general, third party financing appears to be capable in helping stimulate mass production of heliostats and a rapid transfer of central receiver technology to utility and industry. The lower costs of solar plants through mass production and the higher prices that a utility or industry will pay for critical fossil fuels in the future are powerful incentives to encourage investments in the central receiver technology.

DELSOL 2:
A COMPUTER CODE FOR CALCULATING
THE OPTICAL PERFORMANCE AND OPTIMAL SYSTEM DESIGN
FOR SOLAR THERMAL CENTRAL RECEIVER PLANTS

Christine L. Yang
Sandia National Laboratories
Livermore, California

In central receiver systems, a large number of individually tracking heliostats are used to concentrate sunlight on a receiver at the top of a tower. These systems have the potential to deliver thermal energy over a wide range of power levels and temperatures. Applications include central station electric power generation, industrial process heat and production of fuels and chemicals. Analytical techniques are required because it is impractical to investigate experimentally the wide ranges of design and application alternatives for central receivers. Furthermore, the analysis must be computer based because: 1) thousands of heliostats may be required for a single system design; 2) system performance is strongly time dependent due to the motion of the sun; and 3) a large number of options need to be considered in optimizing system design. The DELSOL computer program was generated to fill the need for an accurate, but fast, easy to use and documented code for performance and design applications. Version I, which analyzed large power electric applications, was released in August 1978. The present Version II improves and extends the capabilities of Version I. Version II can handle both large and small power systems for electricity and process heat applications. The code consists of a detailed model of the optical performance, a simpler model of the non-optical performance, an algorithm for field layout, and a searching algorithm to find the best system design. The latter two features are coupled to a cost model of central receiver components and an economic model for calculating energy costs.

Figure 1 indicates schematically how the components of DELSOL are used in the two general classes of application. In (A), the complete system design (which may have been previously optimized by DELSOL) is specified by the user and the code calculates the performance. Typical applications include design point evaluation and analysis of experiments at test facilities. In (B), the heliostat design, the range of system variables to be optimized, and the design constraints are specified by the user and the code calculates optimal designs for a range of power levels. Typical applications include system optimization and component design tradeoff studies.

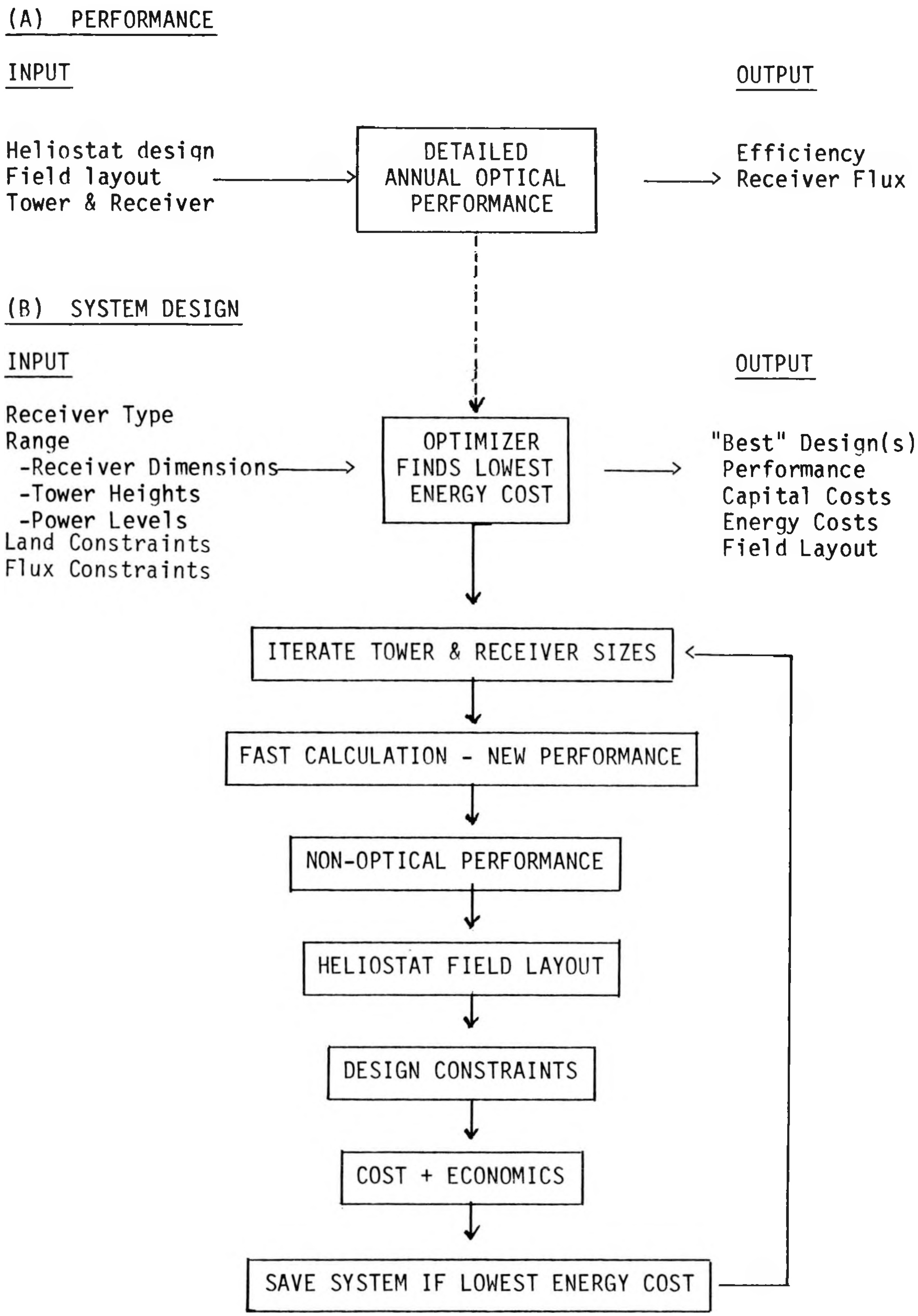


Figure 1. Two General Types of Applications of DELSOL

As an optical performance tool, DELSOL simulates the effects of cosine, shadowing, blocking, atmospheric attenuation, spillage, and flux profiles. The code has several special features. First, the running time for a single performance calculation is much less than for other codes, such as MIRVAL (ref. 1), but with the same accuracy for most problems. Second, because of the analytical form of the spillage and flux, one annual performance calculation determines the performance for any tower height or receiver size. Other codes must perform a new calculation every time the system is varied. DELSOL, therefore, has a very significant advantage in the running time required for the large number of performance calculations necessary in design tradeoff and optimization studies. Third, DELSOL contains a very detailed description of the types of errors that can degrade the performance of heliostats. Finally, DELSOL is relatively easy to use. With minimal input, systems involving flat, focused, or canted heliostats with round or rectangular shapes, external, multiple aperture cavity, or multiple flat plate receivers, and variable aiming strategies can be analyzed.

As a system design tool, DELSOL determines the best combination of field layout, heliostat density, tower height, receiver size and tower position (land constrained system) based on the performance, total plant capital cost, and system energy cost. In this mode, the code can be used to define values of the key design parameters on which a detailed design can be based. The need for manually doing a succession of point designs in the order to identify an optimum is eliminated. The optimal design is evaluated by searching over a range of tower heights and two components of the receiver dimension (e.g., diameter and height of an external receiver) at the design point power level(s) to find the system with the minimum energy cost. The code is also capable of doing constrained optimizations in which the peak flux on the receiver is restricted below some maximum value and/or land availability is limited.

The development of DELSOL followed that of Sandia's other two central receiver performance codes, MIRVAL and HELIOS (refs. 1,2). These two earlier codes have been used to validate the theory and programming in DELSOL. The agreement in performance predictions among the three codes is discussed in Section VII of the User's Manual (ref. 3). While all of the codes can, in principle, do the same kinds of problems, they have been developed with different purposes in mind and thus do not greatly overlap in use. HELIOS is specially adapted for analyzing experiments at Sandia's Central Receiver Test Facility. MIRVAL employs a Monte Carlo ray trace technique, giving it the potential to analyze very complex, but well defined systems. DELSOL has been developed with speed in mind; hence it typically requires much less computer time for performance calculation, and it can also readily handle the multiple performance calculations required for system design and optimization.

DELSOL is based in part on the performance/design approaches developed at the University of Houston (refs. 4,5), but with many important additions. The mathematical basis is an analytical Hermite polynomial expansion/convolution of moments method for predicting the images from heliostats (ref. 4). The method has been extended at Sandia to allow a more general representation of heliostat errors and to incorporate analytical scaling of the images as the tower height is varied (ref. 6). DELSOL also employs a method for optimizing heliostat densities similar to the Houston approach (ref. 5). The primary difference in the two codes is in their design/optimization capabilities. The

Houston approach considers only one tower height and receiver size at a time. These variables must be optimized by manually rerunning the Houston codes until an optimum is located. In contrast, DELSOL automatically optimizes the tower height and receiver dimension(s), saving considerable user and computer time. (The user is cautioned, however, to provide his own values for the appropriate input variables if his system of interest differs significantly in size or cost/performance from the default system description in the code.)

DELSOL is a FORTRAN IV code developed on Sandia's CDC6600 and CDC7600. The memory requirements are $\sim 160_8$ K. The running time varies strongly with the complexity of the problem. Typical running times for performance calculations on the CDC6600 are 60-240 seconds and for design and optimization calculations, 180-1000 seconds.

The User's Manual describes the status of DELSOL as of February 1981. The code is intended to evolve with the development of central receiver technology and revised versions of the code and manual will be released as needed.

REFERENCES

1. Leary, P. and Hankins, J., "A User's Guide for MIRVAL-Computer Code for Comparing Designs of Heliostat Receiver Optics for Central Receiver Solar Power Plants," Sandia Laboratories, Livermore, SAND77-8280, February 1979.

2. Biggs, F. and Vittitoe, C. N., "HELIOS: A Computer Program for Modeling the Solar Thermal Test Facility - A User's Guide," Sandia Laboratories, Albuquerque, SAND76-0346, March 1979.

3. Dellin, T. A., M. J. Fish, and C. L. Yang, "A User's Manual for DELSOL 2: A Computer Code for Calculating the Optical Performance and Optimal System Design for Solar Thermal Central Receiver Plants," Sandia National Laboratories, Livermore, CA, SAND81-8237

4. Walzel, M. D., Lipps, F. W., and Vant-Hull, L. L., "A Solar Flux Density Calculation for a Solar Tower Concentrator Using a Two-Dimensional Hermite Function Expansion," Solar Energy 19, 239-253 (1977).

5. Lipps, F. W. and Vant-Hull, L. L., "A Cellwise Method for the Optimization of Large Central Receiver Systems," Solar Energy 20, 505-516 (1978).

6. Dellin, T. A., "An Improved Hermite Expansion Calculation of the Flux Distribution from Heliostats," submitted to Solar Energy, June, 1979.

USER VIEWS ON SOLAR THERMAL CENTRAL RECEIVERS

Miriam J. Fish
Sandia National Laboratories, Livermore

Introduction

Commercialization of solar thermal central receivers relies on the development of both a reputable supply sector and a reasonably broad based market. While program efforts have tended to concentrate on the former activity through government sponsored research and hardware development and conceptual design studies, some recent projects have been focused on identifying user requirements for accepting central receivers as a viable option for energy production. This article briefly summarizes the findings of interviews conducted in the last two years with a number of utility and private industrial groups regarding central receiver commercialization from the user viewpoint. More detailed discussions can be found in references 1 and 2.

The approach used by the author involved in-depth discussions with each potential user group. The meetings were focused on a set of questions which participants had received a few weeks prior to the meeting. Attendees typically included representatives of energy planning management, financial analysts, and design and operating engineers of the organization. Table I lists the companies contacted. While the number of companies appears small, a significant amount of consensus became evident early in the interview process. Moreover, views in both utility and private manufacturing sectors were broadly similar. The issues discussed are outlined below.

Table I

Companies Participating in User Interviews

Utilities	Private Industry
Pacific Gas and Electric	U. S. Gypsum
Southern California Edison	General Motors
Los Angeles Department of Water and Power	Exxon Enterprises
Public Service of Colorado	Amfac Sugar Co.
Salt River Project	Greyhound Corp.
Nevada Power Co.	Texasgulf Chemicals
Southwestern Public Service	Olin Chemicals
El Paso Electric Co.	
Houston Lighting and Power	
Columbia Gas Systems Services Corp.	

General Requirements for Energy Producing Technologies

A number of points discussed would apply to the evaluation of any energy producing technology. The most important subjects addressed included:

Application

A temperature requirement of ~1000°F in the form of superheated steam delivered to the turbine is typical of utility applications. Plant sizes in the range of 100-300 MW_e, and a technology which can satisfy peaking, intermediate, and/or base load generating demands are of prime interest to utilities.

These characteristics contrast with the diversity of private industrial plants where process temperatures cover the range of 150-2500°F; delivered energy is in the form of hot water, saturated steam, or hot air; and energy demand lies between 1 MW_{th} or less up to 1000-1500 MW_{th}, depending on the process and plant size. Moreover, the energy supply must typically be continuous and highly reliable, or at best, tied to a fixed number of shifts per day, with the added ability to satisfy a characteristic daily load profile. (It can be noted that the central receiver concept with its versatility of operating through thermal storage can meet nearly all of the above requirements.)

Economic Evaluation

Utilities will usually compare candidate options for energy production on the bases of levelized energy cost and $/$kW_e$ capital investment. Industrial practice typically involves calculation of the discounted cash flow over the first 5-10 years of a given project's operation, followed by a comparison of this project with <u>all other</u> investment options (i.e., energy and non-energy related projects) <u>at that point</u> in time. Projects with the most favorable cash flow generally receive the go-ahead.

An economic life of ~30 years for utility applications compares to 20 years for private industry, and a corresponding ~24 year vs. ~16 year tax life is assumed. Utility financing is on the average ~50/50 debt/equity, while industrial practice runs closer to 100% equity. In general, plausible economic scenarios set the debt cost at 3-4 percentage points above the rate of inflation, and the rate of return is 4-5 percentage points plus a risk factor, if warranted, above the debt cost.

Time to Commitment

While this will be a function of project size and maturity of the technology, utilities tend to allow 3-5 years beyond conceptualization for detailed design, obtaining permits, and final management and state utility commission approvals. The absence of state regulation, as is the case for industrial process heat applications, shortens this period to 1-3 years.

Specific Requirements for Central Receivers

Table II summarizes the evolution of central receivers from research and development to full commercialization. The basis for this description is discussed in reference 3 along with recommended activities for each phase. The phased description provides a useful framework in which to discuss user views on central receivers.

EVOLUTION OF SOLAR CENTRAL RECEIVERS

Phase 1 Research and Development	Phase 2 Demonstration	Phase 3 Commercial Development	Phase 4 Commercialized Technology
• Conceive and screen new ideas • Develop technology base	• Establish user confidence and support through adequate system demonstration • Provide small market for heliostats	• Provide economic incentives to build first commercial plants • Provide market for initial mass production of heliostats	• Build full size commercial plants using established designs • Large scale mass production

Phase 1 - Research and Development

Among the utility and industrial groups contacted, the opinions on R&D activities were very much the same. Activities to date were regarded as well focused and carried out. The continuation of site specific conceptual and preliminary designs, component and subsystems testing, and applied research in materials development with special emphasis on lifetime issues was recommended. Summary documentation of R&D progress would be of great interest to user groups as would more opportunities for first hand observation of component and/or subsystem operation.

Phase 2 - Demonstration

While R&D provides required data on component operation, these activities must evolve into a systems integration phase in which all the subsystems are interfaced. Both utility and industrial groups interviewed regard the $10MW_e$ pilot plant at Barstow as the necessary first step along these lines. However, Barstow alone is not viewed as adequate. Additional demonstration projects more closely tied to specific user requirements are needed. For utilities, this translates to a larger plant of $\sim$50 MW_e (4000-8000 heliostats) employing advanced technology options for the solar subsystems and operating for 2-5 years as part of a utility grid. Such a project would provide most utilities with needed reliability data that the smaller Barstow project being operated as a pilot plant cannot.

Potential industrial users agreed on the necessity of additional systems integration projects besides Barstow. Their recommendation differed, however, in that smaller plants of 10-30 MW_{th} (300-1000 heliostats) would suffice, but in contrast to Barstow, these plants should be tied in to existing industrial processes so that the ability of central receiver technology to meet industrial operating requirements can be assessed. The most cost effective technology should be used and the plant operated continuously for 1-3 years in order for the project to be a convincing demonstration.

The user role in these projects should be extensive in all phases: planning and design, construction, and above all, operation of the plants. As "firsts-of-a-kind", however, such plants are viewed as high risk. Therefore most groups indicated that their financial commitment would likely be limited to the value of the fossil fuel displaced by the solar plant. The remaining, and for these plants at this stage of commercial maturity, majority of the project cost would be expected to come from the government.

Phase 3 - Commercial Development

Given the successful operation of the Barstow plant and 2-3 follow-on systems integration projects for the time periods indicated in the previous section, most potential user groups felt that they would be reasonably confident in central receivers as a sound technical option for energy production. Construction of a commercial plant at this point, however, will probably still be more expensive than established alternatives because of added costs for first plant design and engineering and for early heliostat production units produced in the initial stages of mass production (ref. 4). (Estimates of solar plant costs in this phase indicate that the discrepancy will be on the order of 50% above fully commercial costs (ref. 3).) User groups suggested that the government provide financial incentives preferably in the form of tax credits in order to make up the difference and get the technology over the remaining economic hurdle confronting it. The indirect government role at this stage is highly preferred to more direct actions such as low interest loans or grants involving time, red tape, and compromises for the user, not to mention additional administrative costs to the government.

Guidelines for structuring the incentives should be based on the value of solar to the user. For the utilities, this would amount to the capacity credit allowed for the solar plant (determined in large part from the additional demonstration plant recommended after Barstow) plus the fuel displaced for the most competitive alternative (e.g., gas, coal, possible nuclear). For private industrial users, the value would be the capital plus fuel displaced for the cheapest available conventional alternative (thought to be coal in this timeframe).

At this point the user and supplier should be in a position to interact in a normal fashion without direct government intervention. With the construction of capacity totaling $\sim$4000 MW_{th} (or 1000 MW_e at 40% capacity factor) through the help of incentives, the technology should phase into a fully commercialized one in which both technical and economic issues have been resolved (ref. 3).

Summary

Table III is a summary of the comments above for both utility and private industrial users. Several observations can be made:

1. For both potential markets, the technical development steps are the same; namely, R&D followed by operation of the Barstow pilot plant plus some additional systems integration projects. Private industrial users differ from the utilities in that a smaller size demonstration project after Barstow would be satisfactory. However, the diversity of applications in this sector suggests that more than one of these projects would be required to interest a large cross section of this market in the technology.

2. The timing for commercialization in utility markets is marginally slower primarily because of regulation by state commissions.

3. Economic requirements for any project in private industry are somewhat stricter than in utility applications due in large part to a higher fraction of equity financing with its accompanying higher net rate of return. This is balanced, however, by the higher value for solar which is based on premium fuels (gas or oil) or high unit capital costs for small scale coal burning facilities.

4. The government role in commercializing central receivers is to provide:

   a) most of the cost for the systems integration projects following Barstow, and

   b) financial incentives, preferably tax credits, for the first commercial plants built after adequate demonstration of the technology.

5. The user should be assuming increasing responsibility for design and construction of all plants built after Barstow. Until the technology is fully competitive economically, the users expect to cost share up to the value of the plant as discussed above.

References

1. M. J. Fish, "Utility Views on Solar Thermal Central Receivers", Sandia National Laboratories, SAND80-8203, April 1980.

2. M. J. Fish, "Solar Thermal Central Receivers for Industrial Process Heat Generation: User Views and Recommendations for Commercialization", Sandia National Laboratories, SAND81-8235, August 1981.

3. M. J. Fish and L. D. Brandt, "A Plan for the Commercialization of Solar Thermal Central Receivers", Sandia National Laboratories, SAND80-8228, November 1980.

4. L. D. Brandt, "A Strategy for Heliostat Commercialization", Sandia National Laboratories, SAND80-8239, November 1980.

TABLE III

COMPARISON OF INDUSTRIAL AND ELECTRIC UTILITY MARKETS

Topic	Comment	
	Industry	Utilities
• Application†		
- Temperature	150-2500°F	~1000°F
- Form of process energy	Hot water, saturated steam, hot air	Superheated steam
- Plant sizes of interest	1-1000 MW_{th}	100-300 MW_e
- Energy supply	Continuous	Peak, intermediate, or base load
• Economic Assessment	Discounted cash flow for first 5-10 years operation	Levelized energy cost over plant life plus evaluation of capital requirements
• Time to Commitment	1-3 years, once conceptualized	3-5 years, once conceptualized
• Research and Development (Phase 1, Table I)	——<Continue>——	
• Systems Integration Projects (Phase 2, Table I)	——<Necessary>——	
- Barstow	Required first step	Essential as technical demonstration
- Additional	Yes, for industrial applications	Yes, for more realistic utility applications
*Size	10-30 MW_{th} (300-1000 heliostats)	50 MW_e (400-8000 heliostats)
*Operating Period	1-3 years	2-5 years
*Technology	Most cost effective for application	Improved concepts beyond Barstow
- Value of Solar	——<Fuel displaced less perceived risk>——	
- Government Role	——<Provide most of cost for projects>——	
- User Role	——<Operate projects; cost share up to value>——	
• First Commercial Plants (Phase 3, Table I)	——<After adequate demonstration>——	
- Value of Solar	Capital + fuel displaced for conventional alternative (coal)	Partial capacity credit + fuel displaced
- Government Role	——<Indirect>——	
*Incentives	——<Provide tax credits, etc., in timely fashion>——	
*Regulatory policies	Not significant	Revise state public utilities commission policies to allow first plants to be approved readily
- User role	—<Initiate, obtain approvals, construct solar plant in normal fashion>—	
	——<No unusual government interference>——	

†Characteristics for most applications

From Sandia Report SAND81-8235, p. 25.

COMPONENT DEVELOPMENT SESSION

THERMAL SUBSYSTEM DEVELOPMENT OVERVIEW

W. G. Wilson

Sandia National Laboratories, Livermore

The Thermal Subsystem Development Program takes its direction from ongoing system application studies which define technical uncertainties to be resolved and establish development priorities. Development efforts are then focused on the most promising concepts to achieve reliable, and cost-effective components which can meet the system operating requirements. Engineering feasibility experiments are conducted to determine performance, while fabrication studies are conducted to verify cost estimates.

While the collector subsystem represents the largest cost center in Central Receiver applications, the thermal subsystems introduce the greatest technical challenge. As a result, an aggresive program has been established to address the major technical issues and collect the data necessary to confidently proceed with systems integration experiments. Studies underway range from large scale solar experiments at the CRTF to materials interactions, analytical tools and instrumentation development.

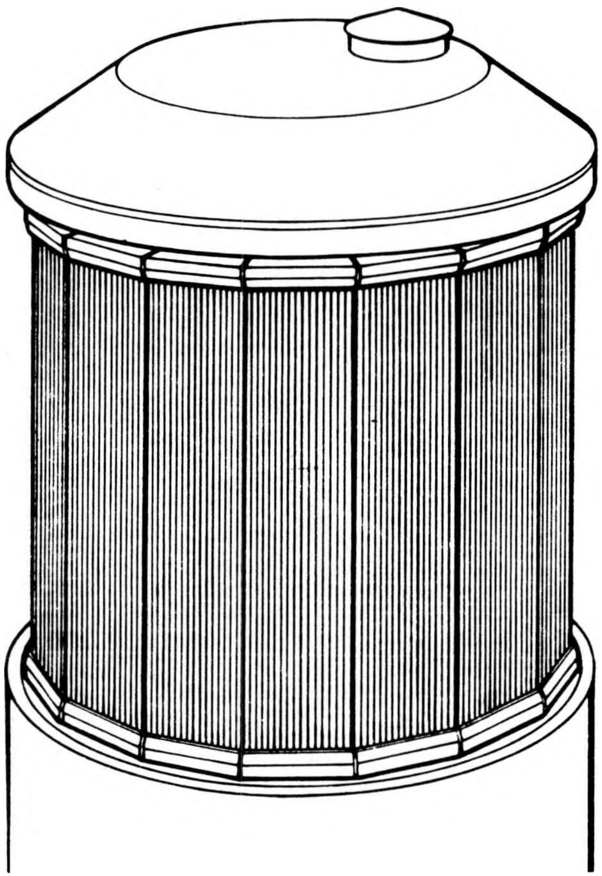
A convenient way to categorize the thermal subsystems development activities is to group them according to receiver working fluids. Figure 1 presents a schematic of the two major receiver configuration (external and cavity) and lists the major working fluids under consideration. Using this framework a brief description of past major activities and current projects will be presented. Those activities which are presented elsewhere in more detail will only be touched on to place them in perspective.

Table I lists past and current major projects in the Central Receiver Thermal Subsystems Program. During FY81 emphasis has been placed on molten salt and sodium working fluids. In the sodium program, the initiation of check-out of the 500 KW_e plant in Almeria, Spain, funded under the auspices of the IEA, has begun. In addition, an experiment is underway at the CRTF to verify the performance of a 1.5 MW thermal peak flux external receiver design. This experiment incorporates the three parallel panel receiver configuration corporately funded by the ESG division of Rockwell International. This will constitute the first solar test of three parallel receiver panels (a difficult controls issue) and will also be a test at more than twice the peak flux tested before. Figure 2 shows a photo of the receiver atop the CRTF.

In the Molten Salt Technology area, a very successful test program of a 5 MW thermal receiver was completed early in the calendar year. Nearly 500 hours of solar test time was accumulated, with about one-half of that time at full power. At the conclusion of the scheduled test program a "hands-on" workshop was held to allow potential users an opportunity to gain first hand knowledge of the experiment. Eighteen different user groups and fourteen different supplier organizations participated. A photo of this experiment during testing is shown as Figure 3.

SOLAR CENTRAL RECEIVER

HEAT TRANSPORT FLUIDS



WATER/STEAM

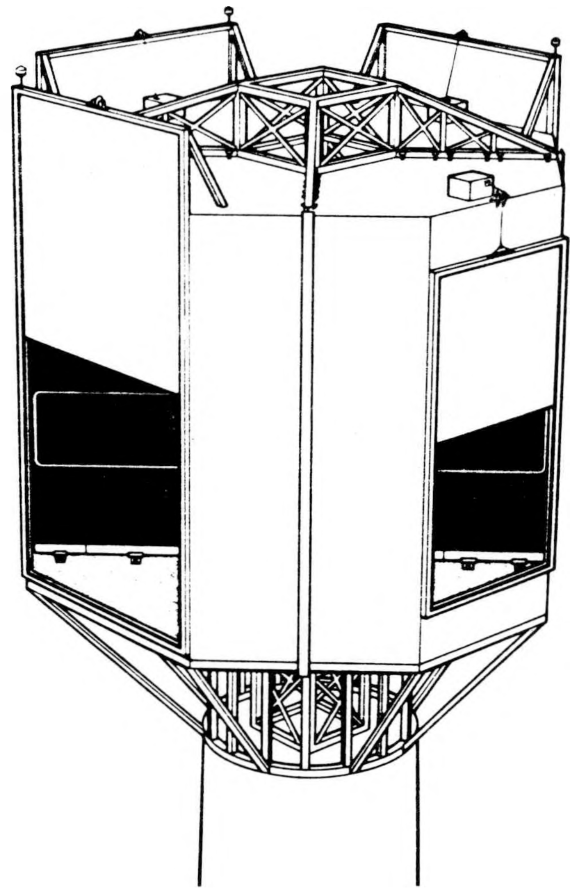
SODIUM

MOLTEN SALT

AIR

HELIUM

OIL



EXTERNAL

CAVITY

Figure 1. Major Receiver Configurations

TABLE I: THERMAL SUBSYSTEMS DEVELOPMENT STATUS

WATER STEAM

- 1 MW CAVITY TESTING COMPLETED - RADIANT AND SOLAR (1976)
- 5 MW CAVITY TESTING COMPLETED - RADIANT (1977)
- BARSTOW SINGLE - PANEL SOLAR TESTING COMPLETED (1979)

SODIUM (PROMISES 10-20% ENERGY COST REDUCTION)

- IEA CAVITY UNDERGOING ACCEPTANCE TESTING
- 3 PANEL EXTERNAL DESIGN BEING TESTED

MOLTEN SALT (PROMISES 20-40% ENERGY COST REDUCTION)

- 5 MW CAVITY TESTING COMPLETE (1981)
- SALT STORAGE EXPERIMENT UNDER CONSTRUCTION
- SALT STEAM GENERATORS BEING DESIGNED
- ADVANCED RECEIVER DESIGNS INITIATED

AIR

- .25 MW CERAMIC MATRIX CAVITY TESTING COMPLETE (1978)
- 1 MW METAL TUBE CAVITY TESTING COMPLETE (1979)
- EPRI FULL SYSTEMS EXPERIMENT PLANNED

HELIUM

- NO MAJOR ACTIVITY

OIL

- NO MAJOR ACTIVITY

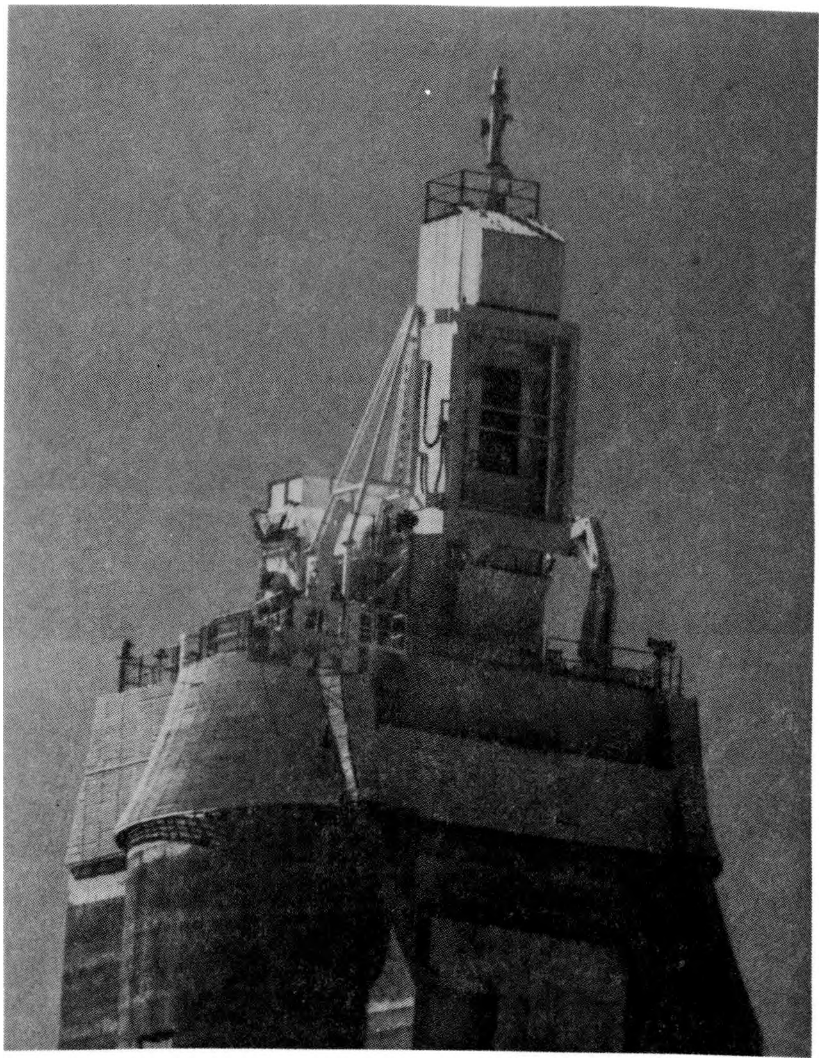


Figure 2. 3-Panel External Design Under Test at the CRTF

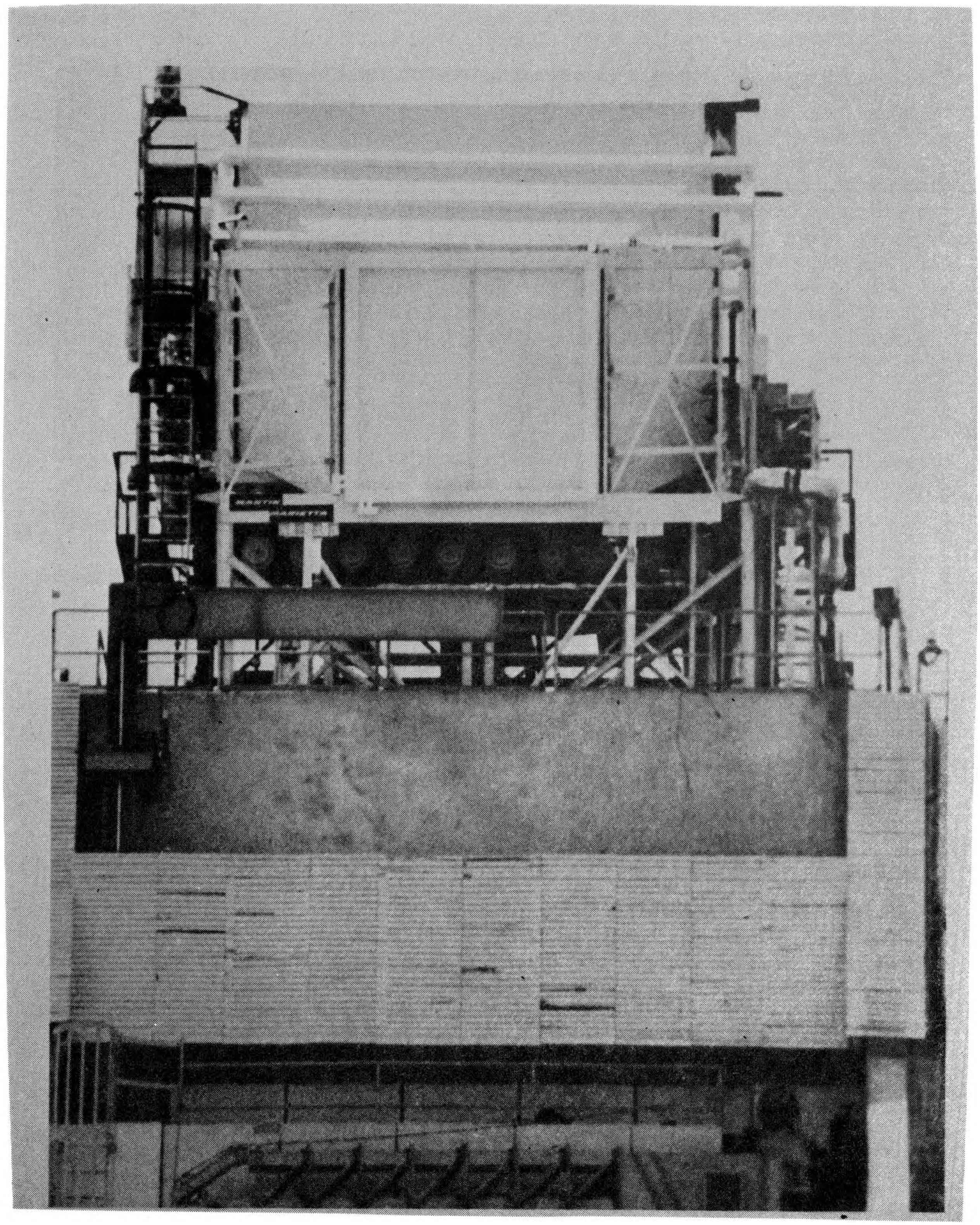


Figure 3. Molten Salt 5 MW Thermal Receiver at the CRTF

Currently a Molten Salt Storage experiment is being constructed at the CRTF. This 7 MW thermal experiment incorporates an internally insulated hot storage tank. This technology has been adopted from LNG tanker designs and should provide a lower cost approach for the containment of 1100°F molten salt. In addition to this large experiment, a smaller unit was successfully cycled 19,000 times to simulate the anticipated fatigue environment. Figure 4 shows a current construction photograph of the experiment.

Since early June, two competitive industrial teams have been performing design tradeoffs on molten salt steam generators. Two different approaches have evolved; a horizontal, U-tube forced recirculation design and a vertical, straight tube with bellows, natural circulation approach. These design studies are due to be completed in March of 1982. Hardware compatible with the molten salt storage experiment now being constructed at the CRTF is anticipated near the end of the calendar year to resolve all technical uncertainties with the selected steam generator approach.

A recently started major activity is the competitive design phase of two molten salt advanced receivers. The intention of these one year, paper studies is the broadening of industrial participation in molten salt receivers and to resolve all process development and other technical uncertainties with the two designs. One design is a quad-cavity approach similar to the Arizona Public Service Repowering design and the other is similar to the omega-cavity approach of the Sierra Pacific Repowering concept.

To support the above major projects, a broad range of special studies are being conducted to provide the data base for confident application of the technology. A brief description will be given of several of these special studies to illustrate the depth in the program.

A concern with the fabrication process for the Barstow water/steam receiver panels centered around the continuous weld on the backside of the panel and the crack notch that is created. Figure 5 shows a cross section of the tubes and the small wedge shaped longitudinal cavity that is created by the weld. Figure 6 shows a microscopic view of the area with sharp crack tips clearly evident. An apparatus was built to experimentally investigate the potential fatigue propagation of the crack tips in a simulated one-sided heating environment. After exposing various samples to 5,000 and 10,000 cycles, nondestructive and destructive evaluation concluded that (a) numerous nucleation sites exist in the panels, but (b) the cracks do not propagate due to thermal cycling.

An additional endeavor geared toward the Barstow project is the development of a dynamic computer model to simulate the plant transient performance. An existing computer program called RELAP which was originally developed to analyze transients in nuclear power plants has been modified for solar applications. To date, the 5-tube hydraulic stability test has been adequately simulated as well as the Barstow single panel CRTF experiment. At the present time, all Barstow subsystems (receiver, storage, turbine, heat exchangers, and valves) have been modeled. Full-plant transient simulations are anticipated in January. Even though the emphasis on this activity has been the pilot plant, the model can be applied to sodium, molten salt and other working fluids.

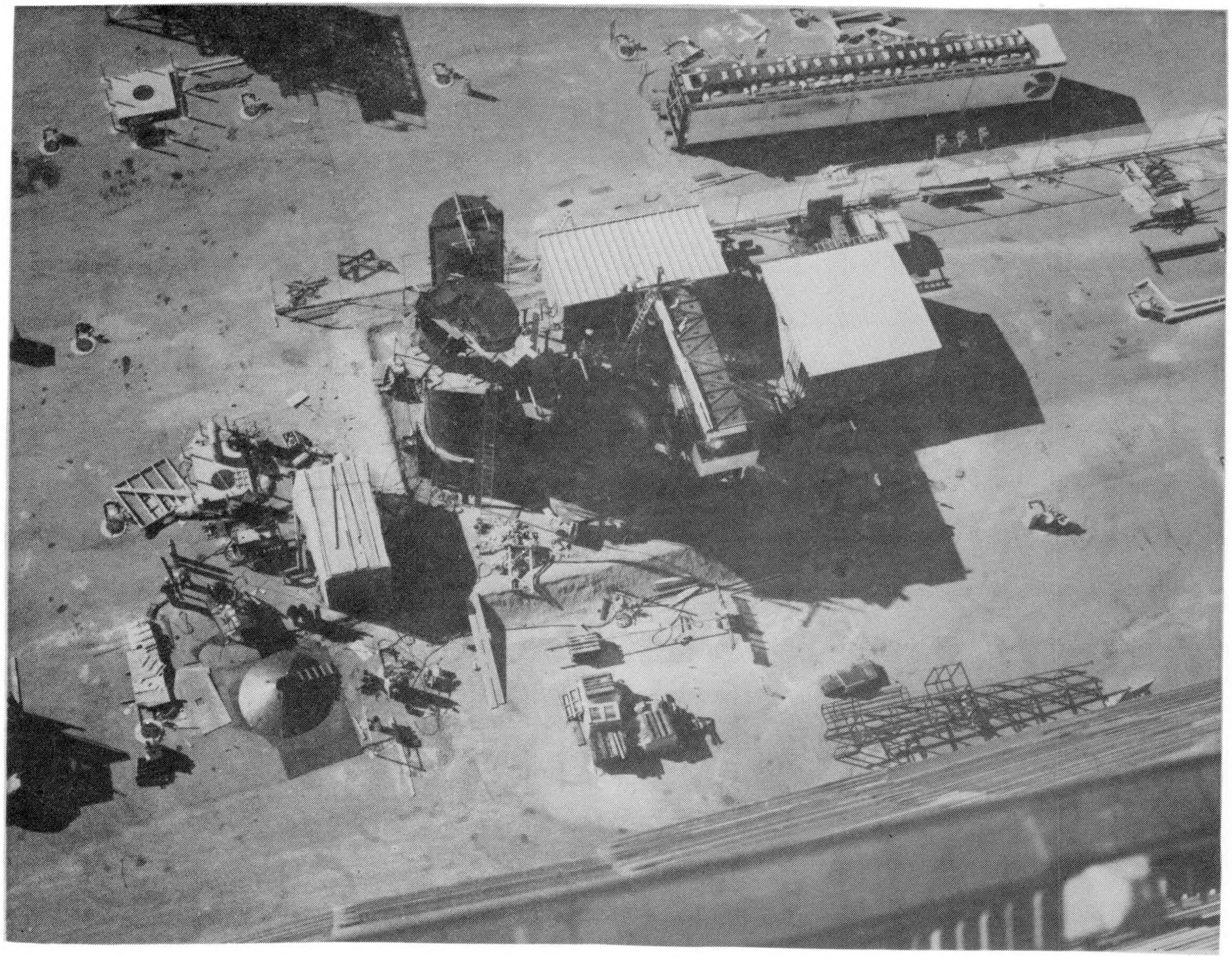


Figure 4. Molten Salt Storage Experiment Under Construction at the CRTF

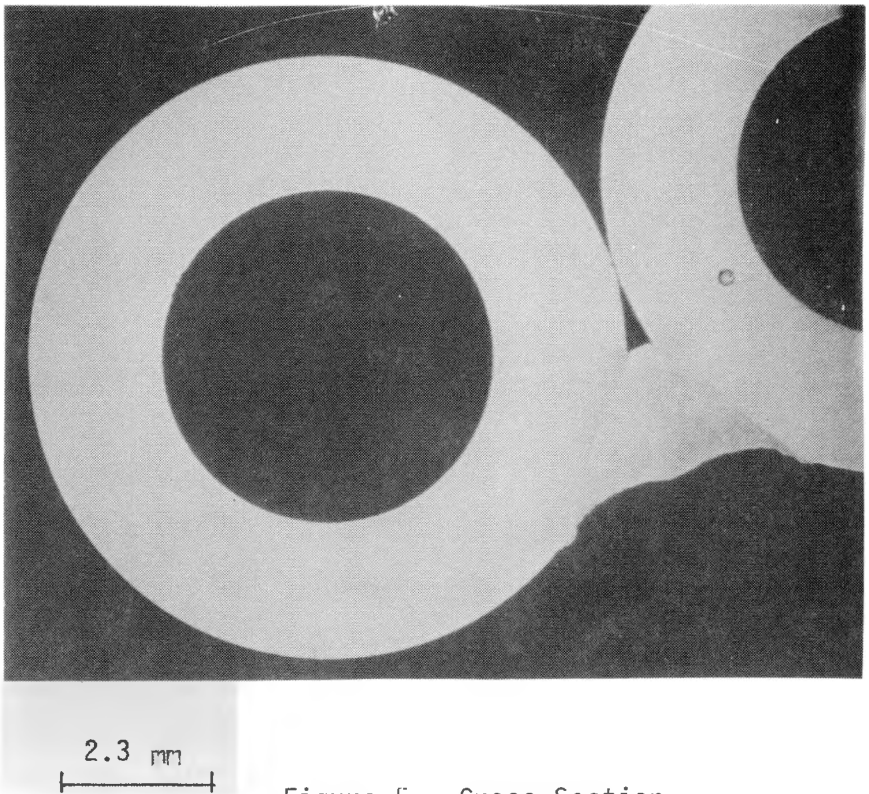


Figure 5. Cross Section

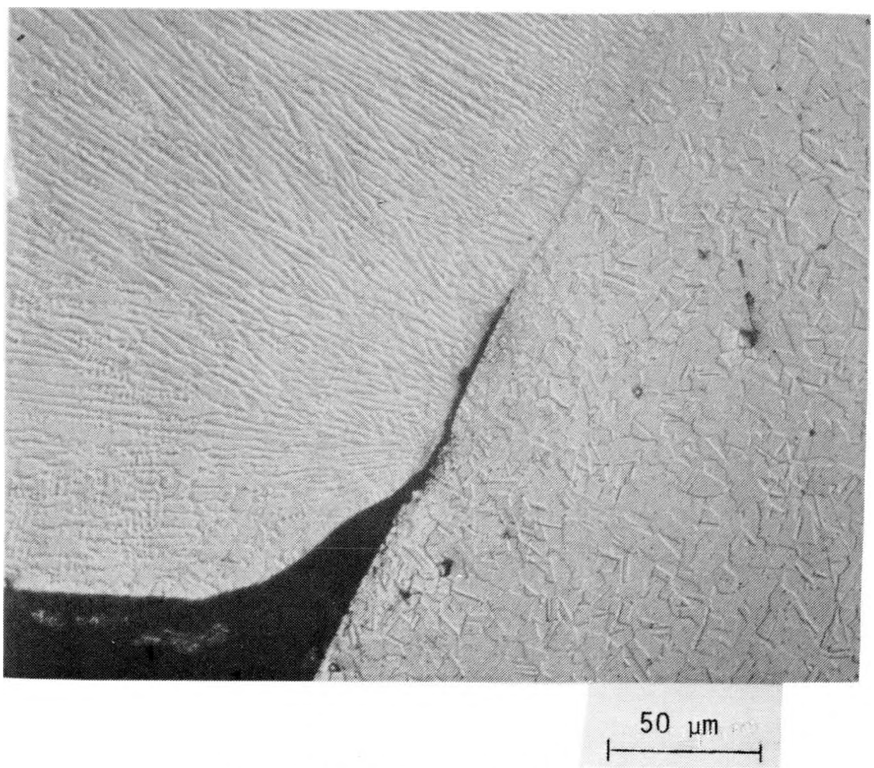


Figure 6. Macroscopic View

In the molten salt area, numerous investigations have been conducted over the last three years to address the chemical and physical properties of nitrate salts and potential containment materials. In general, nitrate salt degradation is not a problem for solar applications up to 1100°F. In addition, a "breathing" storage system (representing the cheapest approach from a containment standpoint) is the best. Similarly, corrosion experiments have shown that an adequate menu of containment materials are available to proceed with confidence. As a bottom line, we see no show stoppers for the solar application of nitrate salts.

As an additional data base for nitrate salt users, we are conducting a user oriented study with Olin Chemical (the only U.S. manufacturer of sodium nitrate). In it will be documented issues relating to shipment, mechanical equipment needed, price breaks, environmental concerns, loading, spill clean-up and disposal. A report will be available in January.

A series of analytical and experimentally coupled studies are being conducted to better understand the energy losses from receivers. One study RADSOLVER* has been published and is now available to calculate the radiation inside cavities. Other studies dealing with convective losses are beginning to show results. A large flat plate experiment is being used to correlate an analytical external receiver model developed by Stanford University and a large cavity experiment is being conducted to correlate a model being developed at U.C. Berkeley. In both cases the analytical tools should help us do a better job designing receivers with the result that improved performance will reduce the cost of the heliostat field required.

*RADSOLVER - A computer program for Calculating Spectrally-Dependent Radiative Heat Transfer in Solar Cavity Receivers by M. Abrams, Sandia National Laboratories, SAND81-8248, September, 1981.

CRTF MOLTEN SALT RECEIVER
SUBSYSTEM RESEARCH EXPERIMENT (SRE)

T. R. Tracey
Martin Marietta Corporation

The primary objective of the receiver SRE is to demonstrate the safe and efficient operation of a thermal receiver for a central receiver power system using molten salt (60% $NaNO_3$, 40% KNO_3) under conditions similar to a commercial receiver including:

1) Salt temperatures
2) Heat flux levels
3) Fluid heat transfer coefficients
4) Startup, shutdown, and cloud transients
5) Power rise rates

Figure 1 is a schematic of the receiver SRE. A vertical cantilever pump circulates molten salt through the receiver system. Salt enters the receiver at 288°C (550°F) and exits at 566°C (1050°F). A control valve regulates the outlet temperature. The salt then enters a forced convection air-cooled heat exchanger where it is cooled to 288°C (550°F). The cooler outlet temperature is controlled by varying the pitch of the fan blades. Salt leaving the cooler returns to the sump.

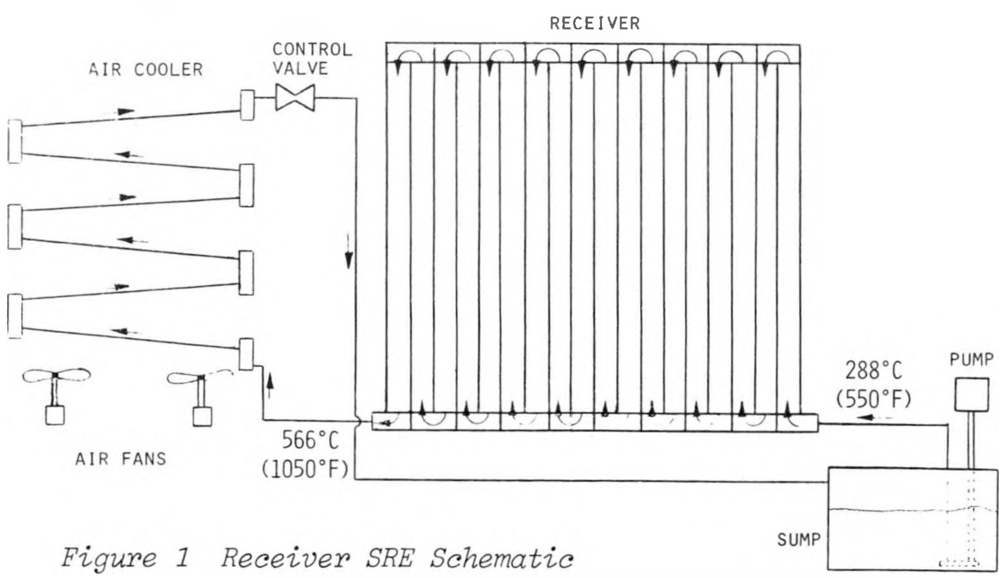


Figure 1 Receiver SRE Schematic

Figure 2 is an artist's concept of the receiver SRE in the cavity configuration atop the CRTF tower. The active surface of the receiver is 3.4 m (11 ft) high by 5.5 m (18 ft) wide. It consists of 288 vertical side-by-side tubes 1.9 cm (0.75 in) in diameter and painted with a high-temperature, high-absorptance paint. The receiver has 18 passes of 16 tubes each. To the right of the receiver is the sump/pump assembly, and behind it is the air cooler.

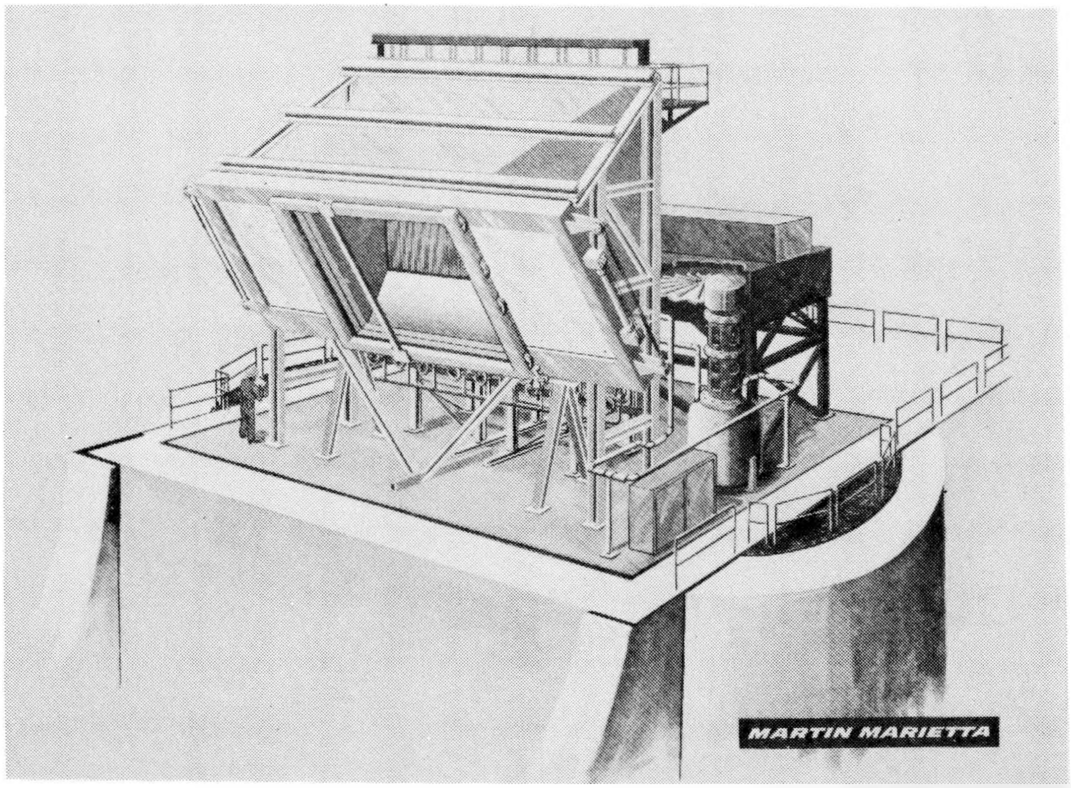


Figure 2 Artist's Concept of Receiver SRE - Cavity Configuration

Table 1 presents the major system design parameters.

Table 1 Receiver Experiment Parameters

Receiver	
Nominal Thermal Rating	- 5 MWt (17×10^6 Btu/hr)
Active Surface Dimensions	- 3.4 m (11 ft) by 5.5 m (18 ft)
Material	- Incoloy 800
Molten Salt Temperatures	- 288°C (550°F) to 566°C (1050°F)
Average Heat Flux	- 0.315 MW/m^2 (100,000 Btu/hr-ft^2)
Peak Heat Flux	- 0.694 MW/m^2 (220,000 Btu/hr-ft^2)
Tube Size	- 19 mm dia. x 1.7 mm Wall (0.75 in. dia. x 0.065 in. Wall)
Number of Passes	- 18
Number of Tubes per Pass	- 16
Pump	
Nominal Flow Rate	- 0.0076 m^3/sec (120 gpm)
Pump Head Rise	- 1.2 MPa (170 psi)
Pump Power	- 45 kW (60 HP)
Air Cooler	
Cooling Capacity	- 5 MWt (17×10^6 Btu/hr)
Molten Salt Inlet Temp.	- 566°C (1050°F)
Molten Salt Outlet Temp.	- 288°C (550°F)

Figure 3 shows the SRE in test at the CRTF. Figure 4 shows the receiver absorber surface and drain valve installations. The receiver is supported from the top by supports which are free to bend to allow for the thermal expansion. The lower receiver supports allow the receiver to grow downward and outward as the receiver increases in temperature. The vertical pump and sump are shown in Figure 5. The SRE can be controlled both from the console in the tower and from the CRTF computer located in the control room. Several methods of control were used. An open loop manual method was used initially and during startup and shutdown. This method consists of remote manual operation of the control valve to control the receiver outlet temperature. The cooler outlet temperature is controlled by remote manual operation of the air cooler fan pitch. The second method used closed loop analog process controllers. The outlet temperature automatically resets flow rate to maintain a desired set point temperature. The cooler outlet temperature automatically resets the fan pitch to maintain a set point outlet temperature. The closed loop analog method does a very adequate job of control with clear sky operation. It was not intended to handle cloudy sky operation. In order to handle cloud transients we developed an anticipatory computer control. Receiver temperatures are used to continually determine the transient energy distribution in the receiver and calculate a flow rate required. This information is used to reset flow to protect the receiver. Table 2 is a summary of the SRE instrumentation.

o TEMPERATURES		506
- RECEIVER TUBES	306	
- RECEIVER HEADERS	18	
- CAVITY	48	
- AIR COOLER	55	
- SUMP	15	
- PIPING	59	
- OTHER	5	
o PRESSURE		5
o SOLAR FLUX		8
o DISPLACEMENT		8
o FLOW RATE		2
- SEGMENTED WEDGE (CONTINUOUS READOUT)		
- IN LINE WEIGHT FLOW CALIBRATION		

Table 2 Summary of Instrumentation

Figure 3 Receiver SRE in Test at the CRTF

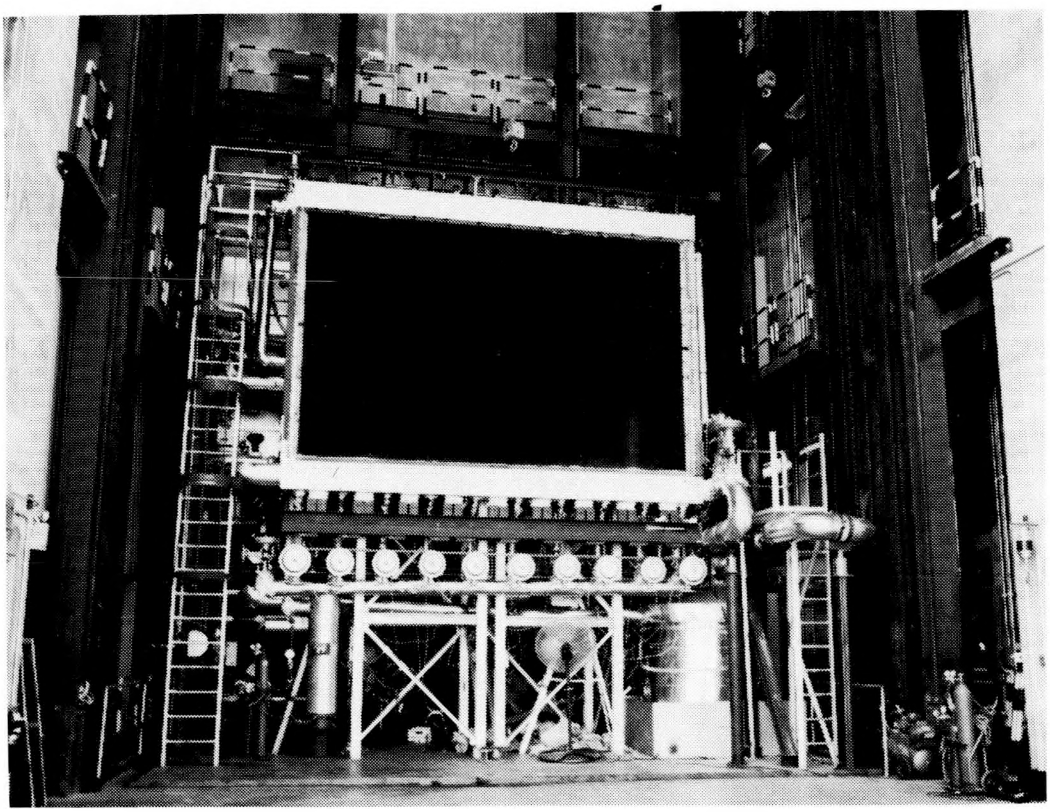


Figure 4 Receiver Absorber Surface

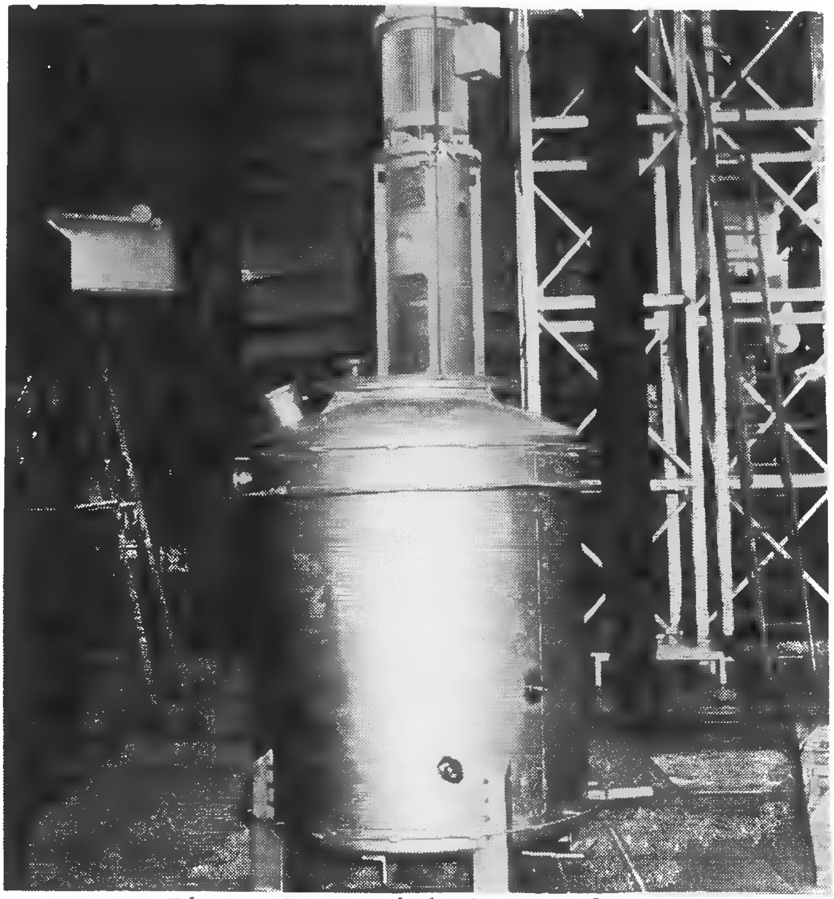


Figure 5 Verticle Pump and Sump

A summary of the testing accomplished during the program is given below:

Total Solar Test Hours. . . . . .495 Hrs.

Total Solar Test Hours at Full Power (200 Heliostats) . . . . .240 Hrs

Total Solar Test Hours at Full Power and Design Temperatures. .130 Hrs.

Peak Power Output (Measured). . . . . .4.7 MW_{th}

The power input to the receiver was measured by use of the RTAF (Real Time Aperture Flux). This device consists of a series of flux sensors located in a vertical bar which sweeps across a plane in front of the receiver aperture. The flux plots are integrated in the computer to determine the power input. The output of the receiver was calculated by multiplying the measured flow rate and temperature rise of the salt by the specific heat. Output versus input data are shown in Figure 6. The data were measured for the standard aim point (center of aperture) and for a to close-in aim point ($\sim$ 1m inside center of aperture). The data for both test conditions are quite consistant. We believe that the reason for the increase in efficiency for the the close-in aim point is the result of reduced incident radiation on uncooled surfaces, particularly on surfaces near the aperture. The radiation enters the aperture at very sharp angles at the top and sides. This will not be the case with commercial systems. Therefore, we believe that the efficiency versus power input for the close-in aim point shown in Figure 6 is more likely the efficiency one would expect in a commercial receiver. At 5MW_{th} input the efficiency is 90%. Our best estimate of the receiver losses are:

	Loss (%)
Reflected Radiation	2-3
Emitted Radiation	5-6
Convection	2-3
Conduction	0.1-0.2

The estimates for radiation losses are based on the results of a computer radiation model. The convective loss is also based on the results of the computer model. However, the computer model parameters were varied to obtain a good match with convective loss tests. The convective loss tests consisted of running the receiver with hot salt without solar input so that the convective loss could be isolated by analysis.

The predicted and measured heat flux levels at the plane of the receiver tubes is shown in Figure 7. The predicted and measured values are quite close, particularly at the peak flux point. We also ran special high heat flux tests by using the close-in aim point for the heliostats. During these tests we measured a peak heat flux of 0.756 MW/m^2 (239,780 $Btu/hr\text{-}ft^2$).

The predicted and measured peak tube metal temperatures versus salt temperature are shown in Figure 8. Considering the difficulty of measuring the tube front side temperatures, we feel that the measured and predicted values are in reasonably good agreement.

The pressure drop versus flow rate is shown in Figure 9. The actual pressure drop is very close to the predicted value.

The computer control system performed quite well. Figure 10 shows the solar insolation versus time during a cloud transient test. Figure 11 shows the receiver outlet temperature over the same period. Even with the severe variations in solar input the receiver outlet temperature was within less than $10^{o}C$ from the set point. Also, we ran step function tests in which we dropped the input solar power from 100% to 37½% within a few seconds by rapidly removing and adding heliostats. During these severe transients the outlet temperature was controlled within $15^{o}C$.

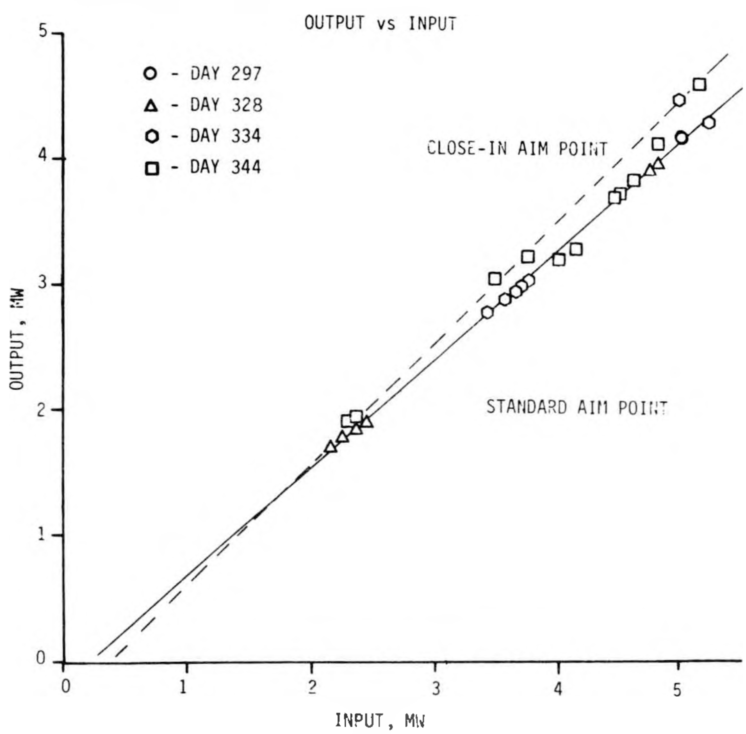


Figure 6 Output vs Input - Aim Point Comparison

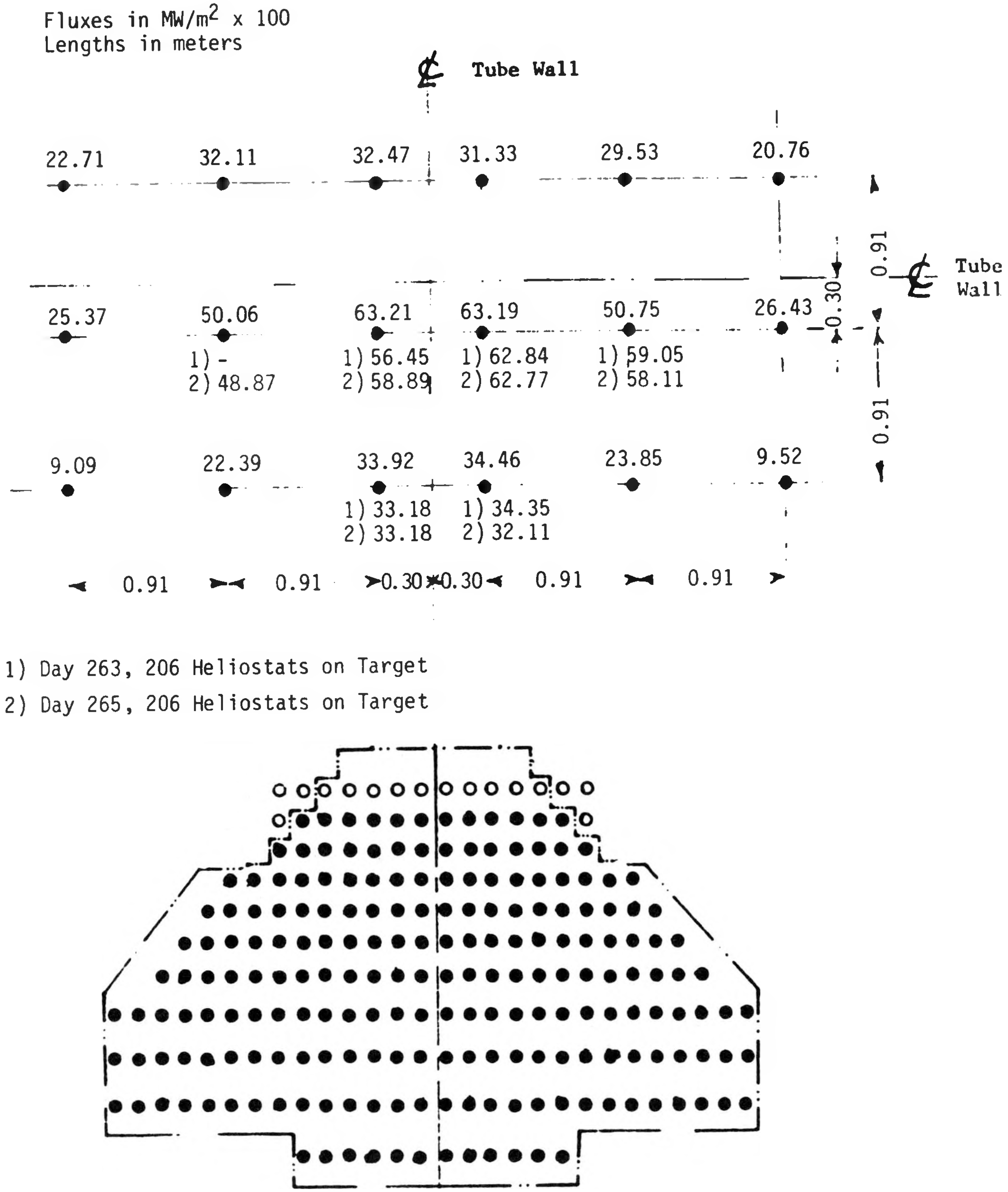


Figure 7 Comparison of Actual and Predicted Flux Levels, MW/m^2

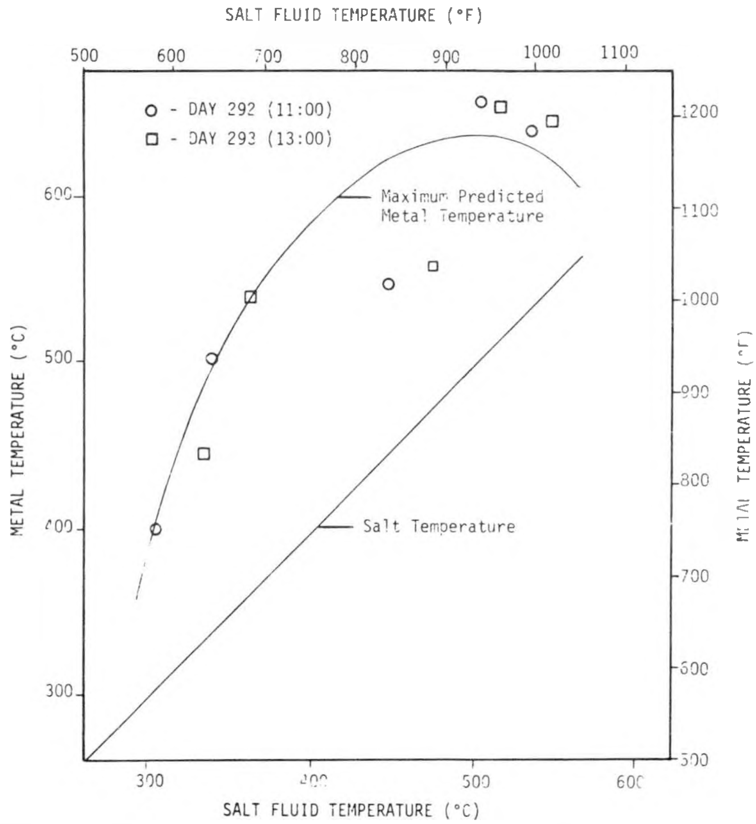


Figure 8 Results - Tube Metal Temperatures vs Salt Fluid Temperatures

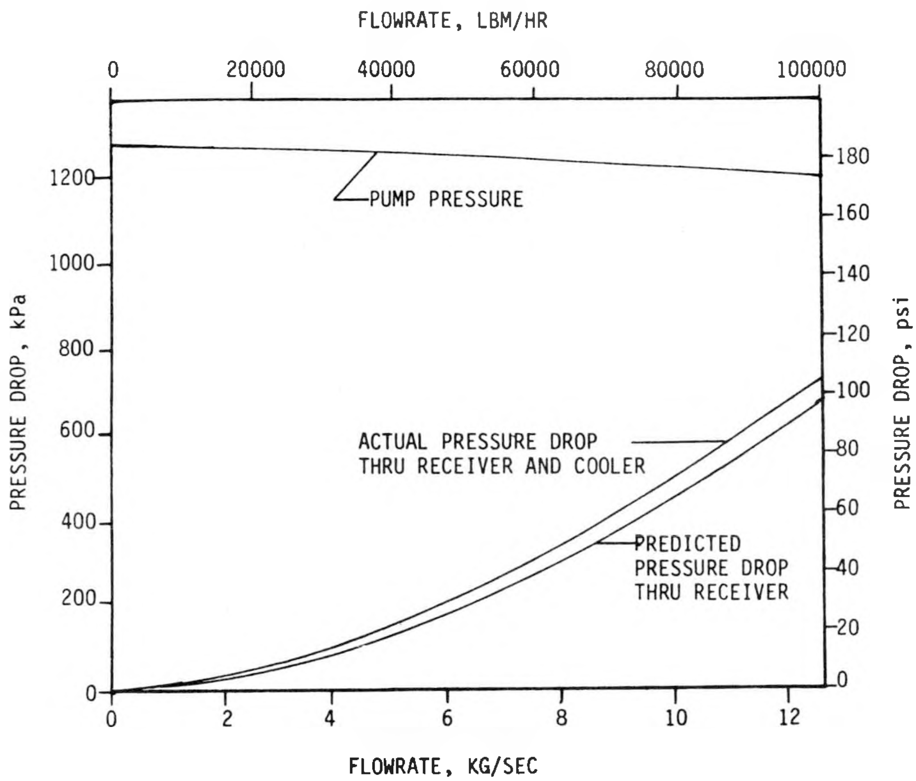


Figure 9 Pressures vs. Flow - Receiver SRE

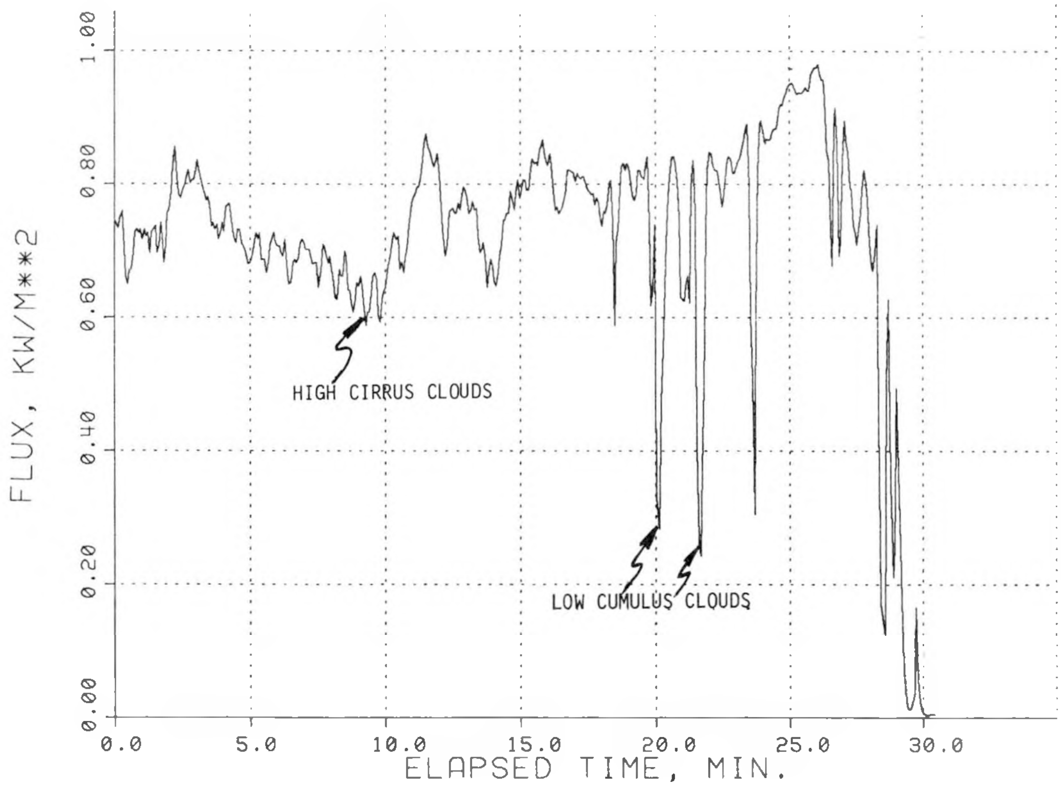


Figure 10 Solar Insolation vs. Time

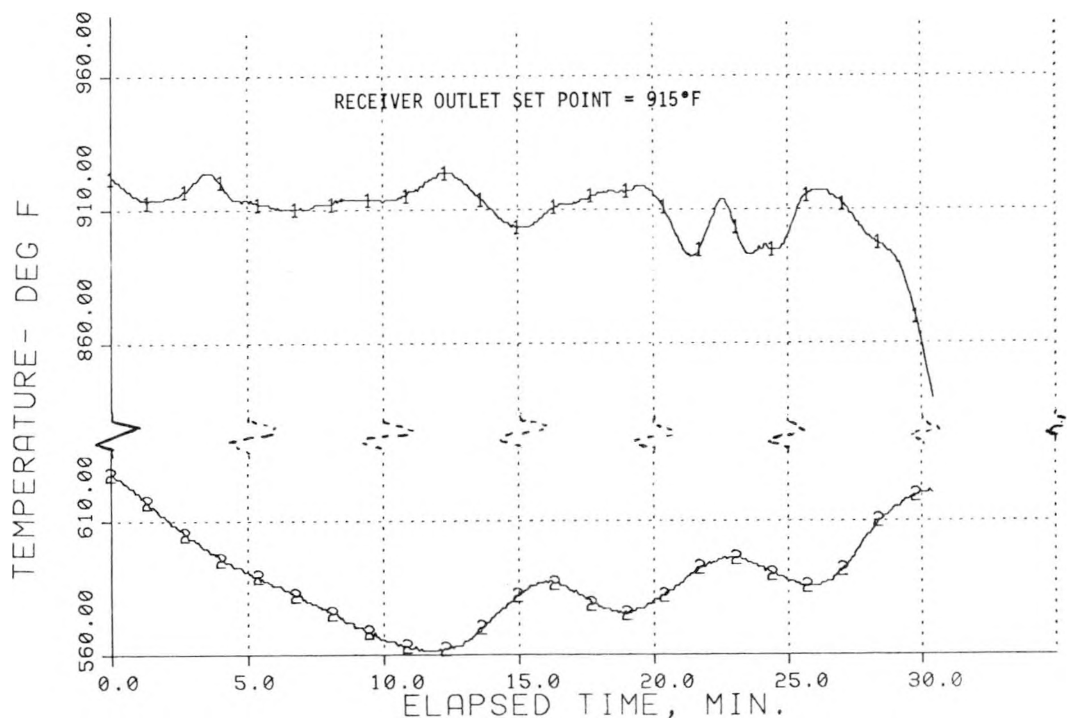


Figure 11 Receiver Outlet Temperature vs. Time

SODIUM SOLAR RECEIVER EXPERIMENT

T. L. Johnson
Rockwell International Corporation
Energy Systems Group

A test of a sodium-cooled receiver panel was started in early October 1981 and is expected to continue well into the first quarter of 1982. The test panel was designed and built by Rockwell International's Energy System's Group (ESG) as a company-funded effort. Testing is being accomplished at the Sandia Central Receiver Test Facility (CRTF) in Albuquerque under a test agreement between ESG and Sandia. The test panel is connected to a sodium flow loop initially supplied to the CRTF by GE but never operated. ESG has a contract with Sandia to assist the CRTF in assembling and operating the sodium loop.

This test has the following general objectives:

1) Provide a proof-of-principle test of sodium-cooled receiver panels.
2) Provide fabrication experience.
3) Provide practical operating experience.

Specific test goals that support these objectives are:

1) Demonstrate satisfactory panel operations at design heat flux and temperature.
2) Achieve a maximum number of diurnal thermal cycles.
3) Demonstrate satisfactory diurnal startup and shutdown.
4) Demonstrate satisfactory nocturnal thermal control.
5) Demonstrate control during insolation changes.
6) Control several panels in parallel.
7) Demonstrate panel dimensional stability.
8) Achieve representative lateral power distributions.
9) Demonstrate acceptable panel thermal losses.
10) Accommodate various simulated emergency conditions.

The solar receiver is the only sodium component for a solar central receiver system without development and test experience. This test will provide the development experience leading to a commercial-type receiver panel.

Panel Description

The ESG solar panel consists of three subpanels operating in parallel, as shown in the artist's concept, Figure 1.

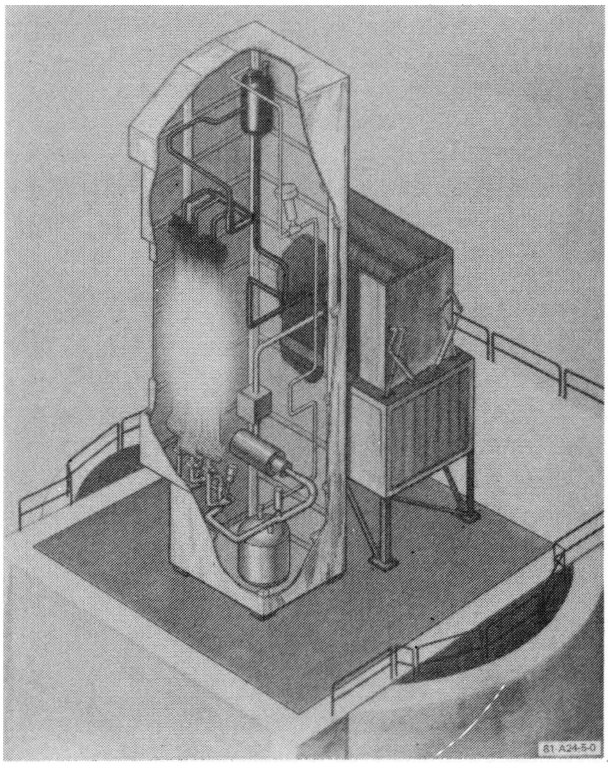


Figure 1. ESG Sodium-Cooled Solar Receiver Panel Test

The subpanels are composed of 21 Type 316 stainless steel tubes, each 3/4 in. in diameter with a 0.049-in. wall. The tubes are butt-welded to 4-in. manifolds such as shown in Figure 2. The overall width of a subpanel is 40 cm (15.75 in.) with an overall length including manifolds of about 530 cm (208.5 in.). The three subpanels are assembled on a test frame with the center manifold nestled in the tube bend region of the outer panels (Figure 3). This arrangement provides a continuous panel surface. The surface is curved on a radius of about 6 m to represent a segment of an external receiver for a repowering application. Figure 3 shows the completed test panel in the ESG manufacturing area.

The active frontal area of the panel exposed to solar radiant energy is 3 m high by 1.2 m wide. This area is surrounded by an insulated frame to protect the subpanel manifold ends and side areas of the loop from spillage energy. The active area of the panel is covered by Pyromark paint to enhance the absorbtivity of the surface. The design absorbed-power capability of each panel is 1 MWt, for a total of 3 MWt for the test article. Maximum operating power will be limited to 2.5 MWt by the heat rejection capability of the dump heat exchanger.

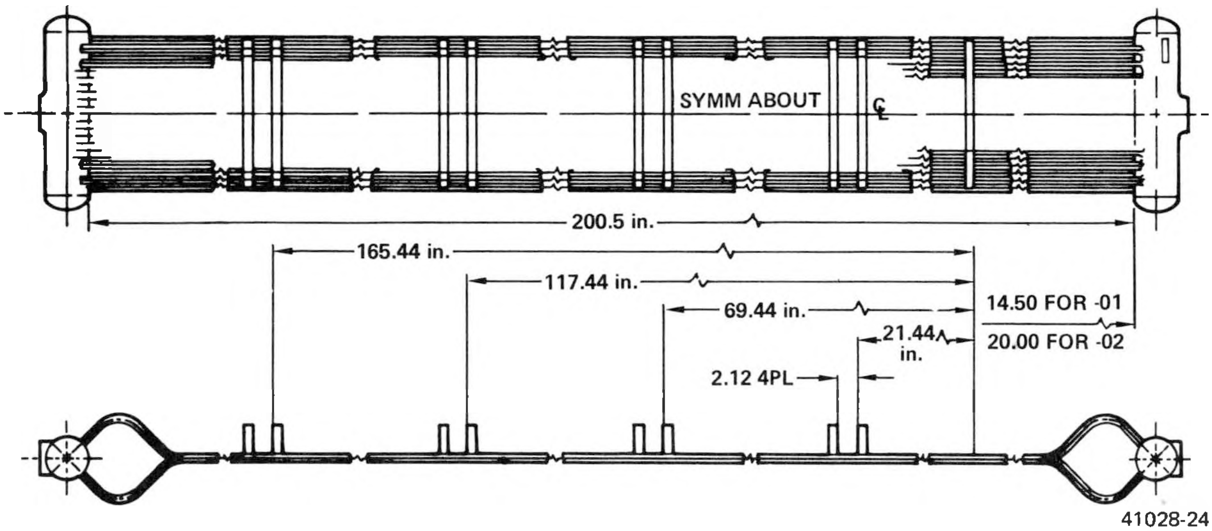


Figure 2. ESG Central Receiver Panel Design

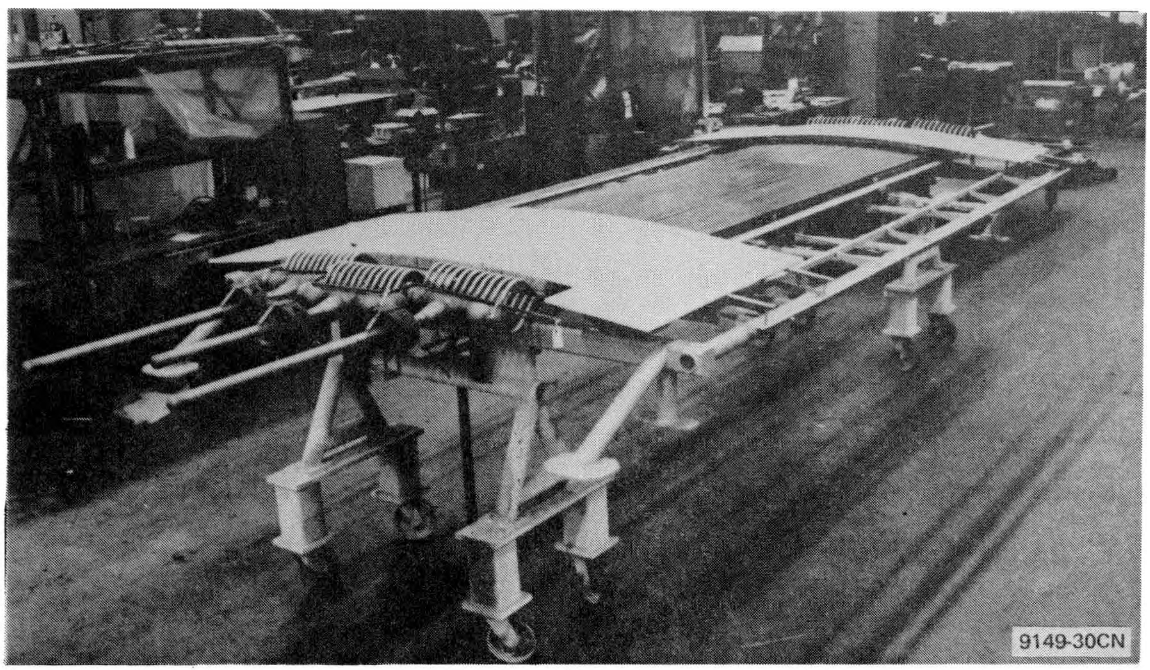


Figure 3. ESG Solar Panel as Assembled for Shipment to CRTF

Peak absorbed heat flux during the test will be 1.5 MWt/m^2. The average flux level over the panel at the operating power of 2.5 MWt is 0.69 MWt/m^2.

The instrumentation on the solar panel consists of 57 thermocouples, three displacement transducers, and three flux sensors. Each subpanel has a electromagnetic flowmeter to measure flow rate and a flow control valve. The flow control valve can be operated manually or automatically by the flow control system. The control system contains the controllers, switches, indicators, and logic to control subpanel flow rate.

The primary control requirement is to maintain the panel outlet sodium temperature for each subpanel at the set-point valve. For the design conditions, this value is 593 ± 14°C (1100 ± 25°F) with an inlet temperature of 288°C (550°F). Since there is a direct relationship between the solar flux available to the panel and the flow required to achieve a given set of operating conditions, solar flux is used as the primary master signal in a feed forward configuration. Panel exit sodium temperature is then processed through a controller (TIC) and used as a trim to this master. The resulting summed signal is then used to modulate the sodium inlet valve position.

An extensive thermal and structural analysis was performed on the test design. The panel is designed to ASME Section VIII Division 1 and ANSI B31.1 with creep fatigue effects for the tubes evaluated according to the high-temperature Code Case ASME N-47. The design meets the specific test conditions and safety requirements imposed by the CRTF on test articles for that facility. In addition, the panel tubes in the high-flux region were analyzed for commercial application with a reasonable expectation for a 30-year life.

Sodium Loop Description

The ESG test article is connected to a CRTF-installed sodium loop, as shown in Figure 4. Loop assembly was started in March 1981 by CRTF personnel, with assistance from ESG.

A flow schematic for the sodium loop is shown in Figure 5. Sodium circulation through the test panel is provided by an electromagnetic (EM) pump with a capacity of 0.01 m^3/s (175 gpm) at a developed head of 200 kPa (30 psig). Nominal flow rate through the test panel is 0.007 m^3/s (115 gpm). The pump flow control system will be largely inactive for this test, and flow control is achieved by the panel flow control valves as explained above.

Liquid sodium enters the test panel at a temperature of 288°C (550°F) and under normal operation exits at a temperature of 593°C (1100°F). A flow-through surge tank is provided to accommodate changes in sodium volume in the system. Argon cover gas is provided in the surge and drain tanks. The sodium is cooled by the dump heat exchanger (DHX) from 593°C (1100°F) nominal temperature to 288°C (550°F) before circulating back to the EM pump. The heat removal capability of the DHX is changed by varying the airflow through the unit. Airflow, in turn, is varied by two continuously variable speed controlled fans. Louvers are also provided for additional control. A preheat system and doors are provided on the unit to maintain a temperature at night of about 204°C (400°F). The DHX has a control system to maintain an outlet temperature of 288°C (550°F). Computer modeling studies have

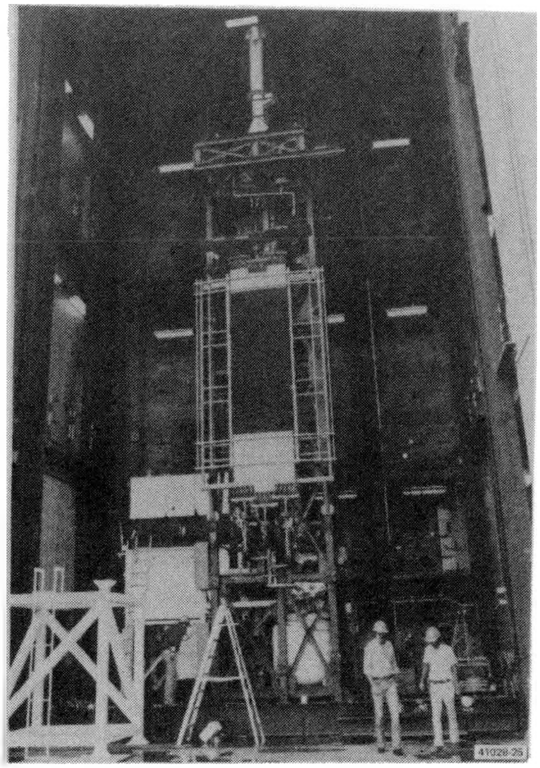


Figure 4. ESG Solar Panel
Installed on the Sodium Loop
Structure at CRTF

shown that the test panel control system and the DHX control system operate with a minimum of interference.

At night, the sodium in the loop is drained into the drain tank, where it is maintained by the electrical heat tracing at a temperature of 204^{o}C (400^{o}F). All sodium piping in the system is heat traced, insulated, and maintained at temperature throughout the night. The window area of the test panel is allowed to cool to ambient conditions.

Test Description

The test activity for the ESG solar panel is divided into the following phases:

1) Dry checkout
2) Wet checkout
3) Low power
4) Intermediate power
5) Design power.

The dry checkout tests are accomplished prior to loading sodium into the system and consist of a functional checkout of the mechanical, electrical, and instrumentation items in the system. Upon successful completion of the dry checkout, the loop drain tank is loaded with about 200 gal of liquid

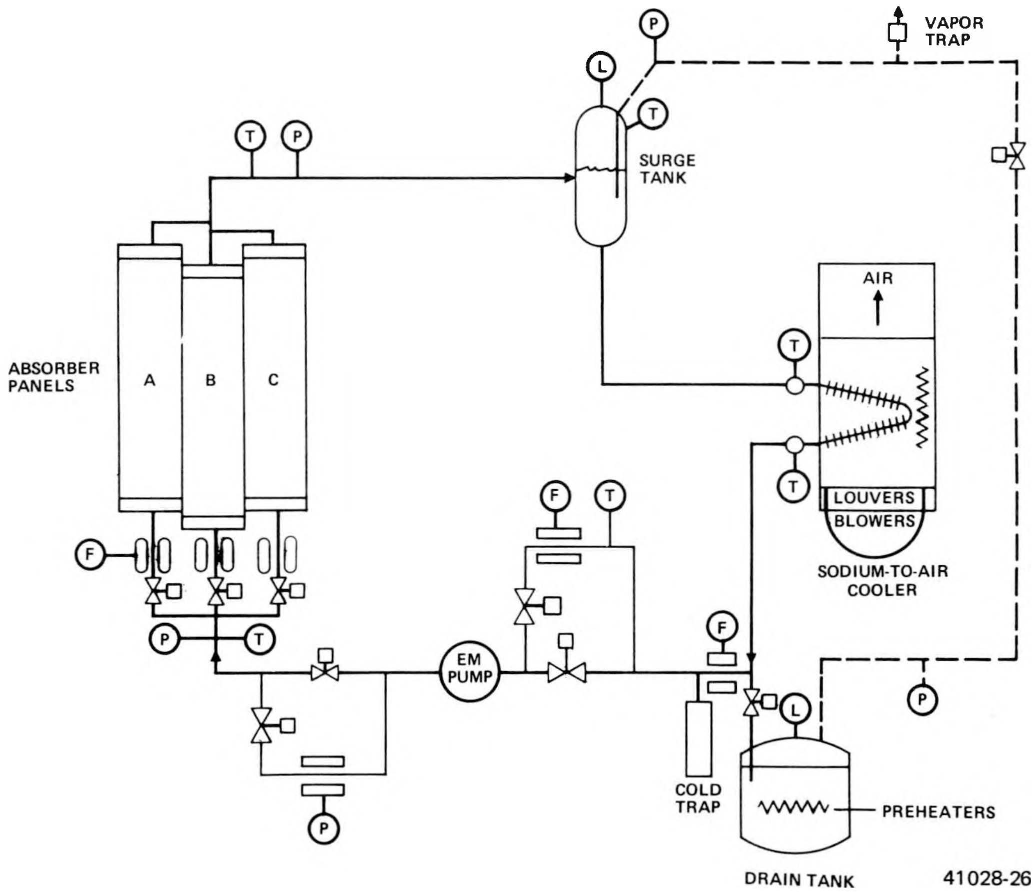


Figure 5. Flow Schematic for Sodium Loop at the CRTF

sodium from 55-gal drums. Wet checkout is accomplished by establishing sodium flow in the loop and repeating the functional checks accomplished during the previous step. These checkout items are completed with the test system at ground level. With successful completion of the checkout items at ground level, the test system is raised to the top of the CRTF tower.

Low-power and intermediate-power tests are accomplished primarily to allow the sodium system operating crew to develop experience with the manual and automatic controls and coordinate these activities with the heliostat operation. Once this operating experience is attained, the majority of the testing is accomplished at the design power conditions.

Testing is scheduled for a 5-month period with one-shift operation starting in October. The goal of this test program is to accumulate about 350 h of test time.

The test panel will be drained each night and at any time that there is insufficient solar energy to maintain the active panel surface at a temperature of 204^{o}C (400^{o}F). The daily schedule is as follows:

1) Pretest briefing and safety review
2) Maintenance review
3) Establishment of panel preheat (six heliostats)

4) Pressure fill of system with sodium
5) Establishment of sodium flow and power buildup
6) Test activities
7) Decreasing power and shutdown
8) Draining sodium to drain tank
9) Activation of electrical preheat.

A majority of the testing is accomplished with a flat profile such as shown in Figure 6, with the low- and intermediate-power testing at the one-third and two-thirds power level, respectively. Some of the testing will be accomplished with the skewed distribution shown in Figure 7. This distribution is selected to give a temperature gradient across the test panel of 3°F per tube. This value is typical of the gradient imposed on an external receiver for commercial applications. During a typical day, the north panel of an external receiver is subjected to a skewed distribution, shifting from a left distribution in the morning to a right distribution in the afternoon. This condition will be tested periodically during the program.

The ESG sodium-cooled receiver panel test is an important accomplishment in preparing for the design and construction of solar repowering or stand-alone plant applications. One such application is for the advanced conceptual design study being conducted by ESG with West Texas Utilities for Paint Creek Station Unit 4. All other sodium components of the appropriate size for this plant application have been designed, built, tested, and operated in sodium facilities.

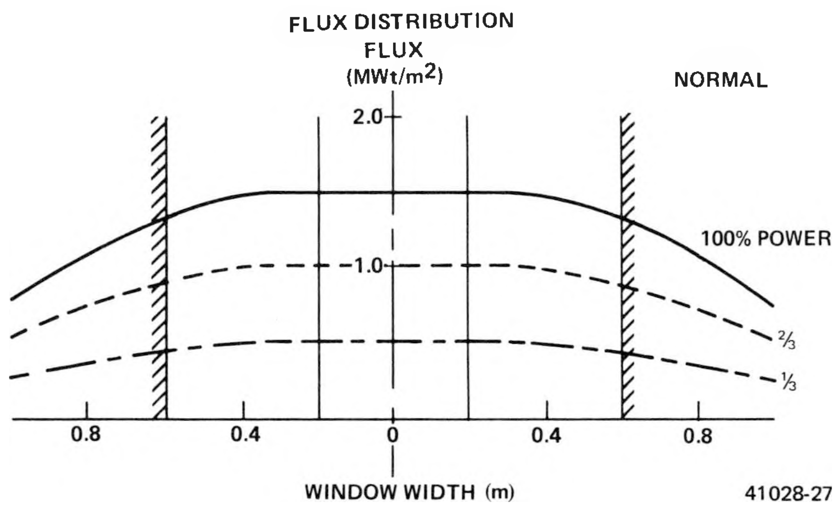


Figure 6. Heat Flux for Normal Flux Distribution (Two-Point Aim)

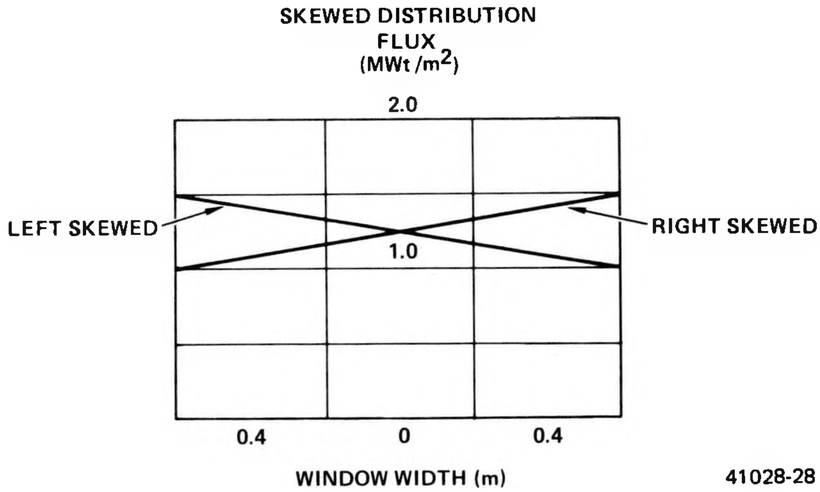


Figure 7. Flux Distribution (Reference to Peak Flux = 1.5 MWt/m^2) Across Three Panels (Maximum Edge-to-Edge Flux Ratio for All Three Panels $\leq$ 1.4)

PROGRESS REPORT: MOLTEN SALT STEAM GENERATOR SUBSYSTEM RESEARCH EXPERIMENT
PHASE 1 - SPECIFICATION AND PRELIMINARY DESIGN

George Grant
Babcock & Wilcox Co.

Introduction

Under contract to Sandia National Laboratories, the Babcock & Wilcox Company is engaged in development of steam generator subsystem and component designs for solar power applications using molten nitrate salt coolant. Subcontractor support is provided by Martin Marietta, Black & Veatch Consulting Engineers, and the Arizona Public Service Company.

The principal objectives of the program are:

1. To select an optimum steam system arrangement for both stand-alone and repowering applications.

2. To establish cost-effective heat exchanger designs based on conventional fabrication processes.

3. To prepare Comprehensive Equipment Specifications.

During the course of the study, plans for a subsystem research experiment will be developed. This experiment will be directed to demonstrating predicted performance, resolving design uncertainties, and reducing cost through prudent reduction of design margins.

Work was initiated in June, 1981, and is scheduled for completion in April, 1982.

System Description

The arrangement of the major components in the steam generator subsystem is shown in Figure 1. Within the subsystem, five functions are accomplished: The feedwater is preheated to the evaporation temperature, the water is evaporated to steam, the steam is separated from the recirculating fluid, the steam is superheated for delivery to the high-pressure stage of the turbine, and the steam is reheated for expansion in the intermediate and low-pressure stages of the turbine.

The system can be readily modified for non-reheat cycles by eliminating the reheater, and can be used for repowering applications by placing the steam generators in parallel with an existing fossil-fueled boiler. For industrial process heat applications, the basic design can be modified to provide a wide variety of steam conditions.

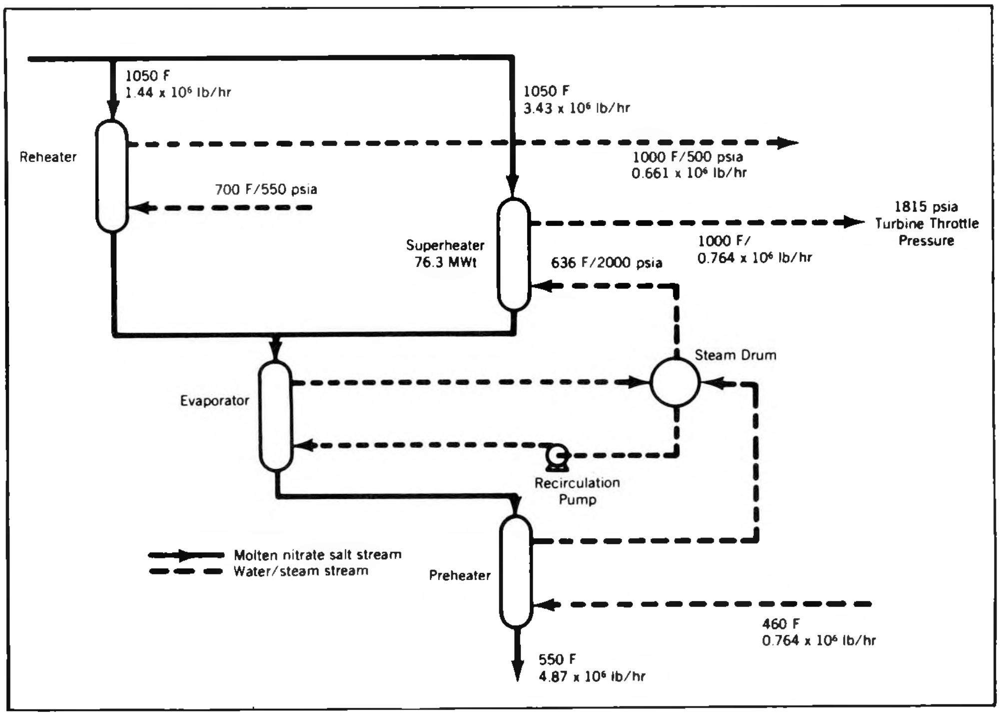


Figure 1 Steam System Arrangement

Work Accomplished

During the first three months of the contract, conceptual design studies have been completed, and preferred steam system arrangement and component configurations have been selected. A preliminary draft of the subsystem and component specifications has been developed and a design analysis plan has been prepared. The results of this work are described in the following paragraphs:

Specifications - The subsystem and component specifications define plant interface parameters, design criteria, codes and standards, and operational modes and transient response requirements. This document will be upgraded periodically during the contract to incorporate detailed information derived from the design effort.

Steam System Arrangement - Recirculating, once-through (or Bensen), and spill-over (or Sulzer) steam system arrangements have been considered. The applicability of these candidate systems to both stand-alone and repowering service was evaluated based on overall cycle efficiency, total plant and component cost, operational requirements and control system complexity, and water chemistry and balance-of-plant material limitations. An overview of the selection process was provided by Arizona Public Service Company, and the Southern California Edison, Pacific Gas and Electric, and South-Western Public Service companies were canvassed to supplement the APS review.

Based on this investigation, the recirculating steam system was selected. This type of system is used exclusively throughout the power industry where frequent startups and load swings must be accommodated. It is uniquely suited for the diurnal cyclic service required in solar power applications. The typical layout of the components is shown in Figure 2.

A once-through system requires high-purity feedwater to avoid deposition of contaminants on evaporator surfaces. Achievement of the necessary water quality at candidate repowering sites would be prohibitively expensive as it would require substantial outlays for new water treatment equipment and high-alloy feedwater heaters. This system is unattractive for both stand-alone and repowering applications, even where adequate condensate polishing equipment exists, since considerable time will be required to return the feedwater to once-through quality prior to each daily startup.

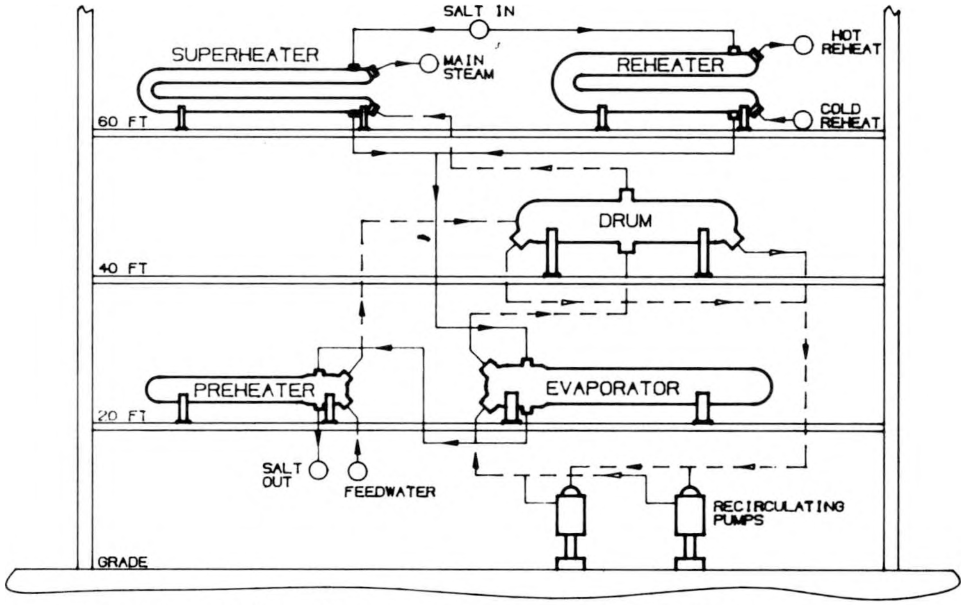


Figure 2 Layout of Steam Generator Components in Turbine Building

Inherent in the Sulzer System are high blowdown rates leading to large unrecoverable thermal losses. The resultant poor cycle efficiency mandates unacceptable collector and receiver subsystem cost increases.

Steam Generator Components

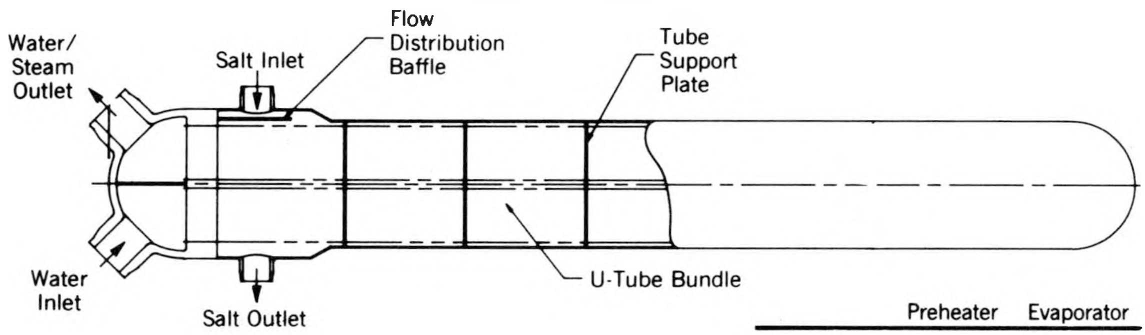
Numerous heat exchanger configurations, including U-tube, straight-tube, helical coil, and serpentine tube bundles have been examined for application in the recirculating steam system. These candidate designs have been compared on the basis of performance characteristics, structural integrity and capability for withstanding operational transients, component cost and fabricability, reliability, and maintainability.

Based on this investigation, the concept chosen for the preheater and evaporator is a U-tube bundle housed in a single straight shell. While U-tubes have also been selected for the superheater and reheater, the large steam-side terminal temperature differences impose unacceptable thermal stresses on a single tubesheet. Therefore, a U-shell arrangement is used to house the bundle. The component designs are shown in Figure 3.

The components are horizontally oriented, with nozzles arranged to facilitate venting and draining. With the horizontal orientation, building costs are reduced, both in building height and component support. For southwestern United States plant locations, where turbine enclosures are not required, the components may be supported on foundations at grade level.

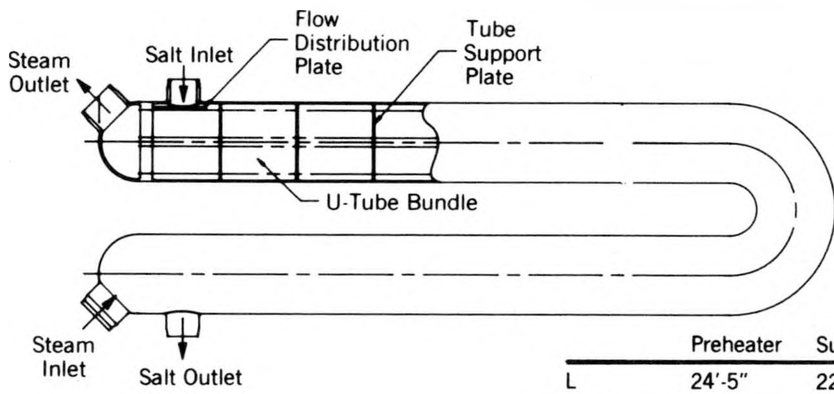
Materials have been selected to assure adequate mechanical strength and corrosion resistance in the operating environment: carbon steel for the preheater, 2 1/4 Cr - 1 Mo for the evaporator, and type 304 stainless steel for the superheater and reheater.

Preheater/Evaporator



	Preheater	Evaporator
L	36'-10"	33'-6"
D	60"	72"
# Tubes	2533	1200
Tube OD	0.5"	0.875

Reheater/Superheater



	Preheater	Superheater
L	24'-5"	22'-6"
D	28"	24"
# Tubes	836	741
Tube OD	0.625	0.5

Figure 3 Steam Generator Components

Work Planned

The following work is now in progress or planned for completion during the current program:

1. The design of the selected components, component supports, piping arrangement, and control system will be completed.

2. A subsystem model will be prepared and steady-state and transient performance simulated.

3. Plant and component cost estimates will be prepared.

4. A development program will be defined, and plans for a subsystem research experiment will be completed.

MOLTEN SALT STEAM GENERATOR SUBSYSTEM RESEARCH EXPERIMENT

Stephen J. Goidich
Foster Wheeler Solar Development Corporation
Livingston, New Jersey

Introduction

Studies funded by DOE have shown that molten salt (60% $NaNO_3$, 40% KNO_3) is the most economical receiver coolant and storage fluid for solar plants requiring large amounts of thermal storage. Although molten salt has been used successfully in process heat applications for many years, it has not been used as a heat-transfer medium for generating high pressure [12.5 MPa (1815 psia)] high temperature [540°C (1000°F)] steam for power generation. There have been a number of recent studies of solar thermal power plants using molten salt, but these were primarily concerned with the design and operation of the overall plant. Consequently, important steam generator design and operating considerations were not covered in depth.

The subject study presently being conducted by the Foster Wheeler Solar Development Corporation is Phase 1 of a two-phase project whose objectives are:

- o Develop reliable, cost effective molten salt steam generating subsystem for solar thermal plants.
- o Minimize uncertainty in steam generator subsystem capital, operating and maintenance costs.
- o Demonstrate ability of molten salt to generate high pressure, high temperature steam.

The Phase 1 study involves the conceptual design of molten salt steam generating subsystems for a nominal 100-MWe net solar central receiving electric generating plant (100-MWe solar stand-alone), and a nominal 100-MWe net fossil-fueled electric power generating plant which is 50 percent re-powered by a solar central receiver system (50-MWe hybrid). As part of Phase 1, a proposal will be prepared for Phase 2 which will involve the design, construction, testing, and evaluation of a Subsystem Research Experiment (SRE) of sufficient size to ensure successful operation of the full-size subsystem designed in Phase 1.

The period of performance for the Phase 1 study is from June 12, 1981 to April 12, 1982. The study cost is $555,000.

Project Status

The project consists of eight major tasks as noted in Figure 1. The project is presently in the beginning of the fifth month. Project highlights completed to date include the following:

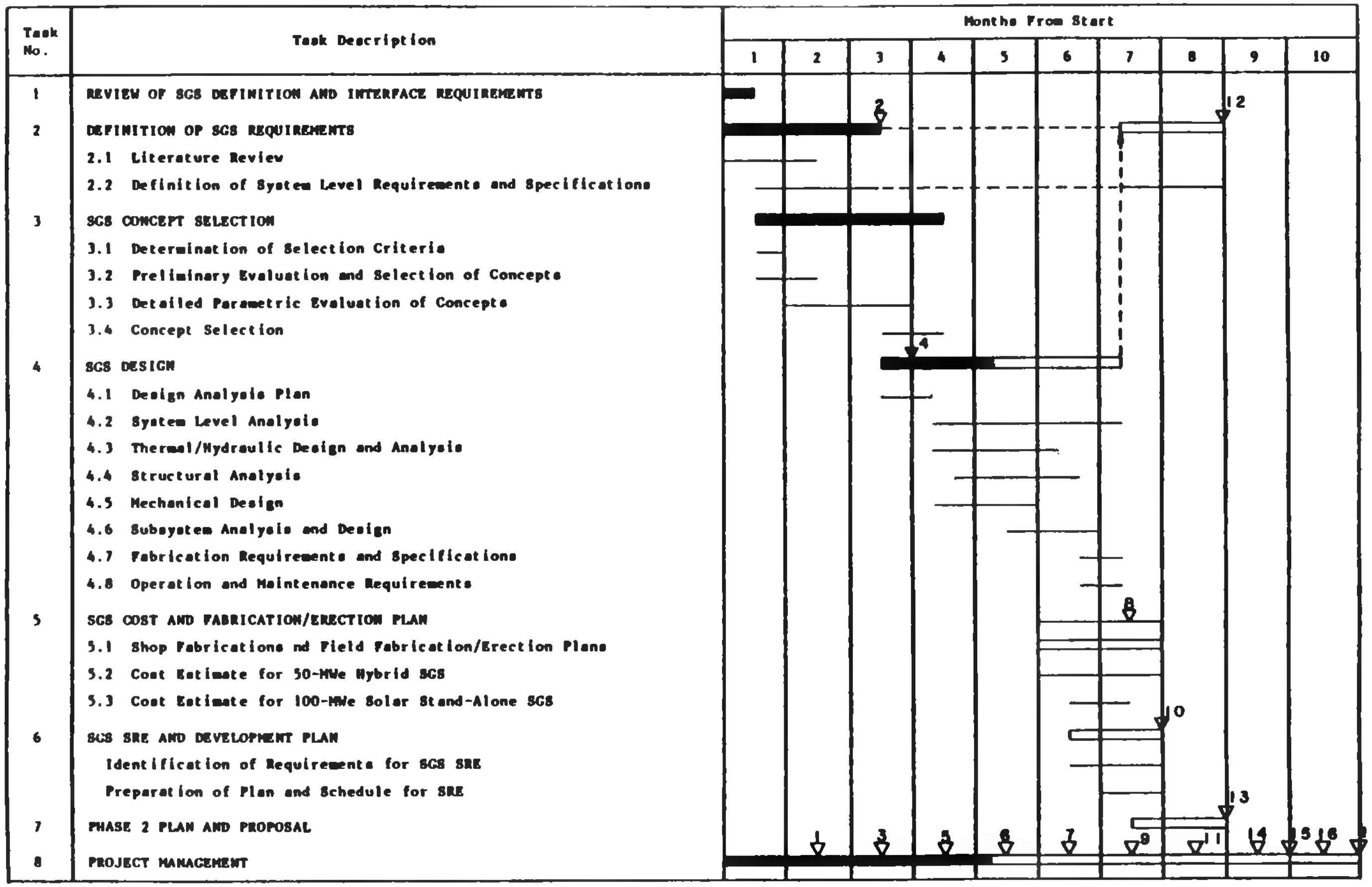
- o Review of SGS Definition and Interface Requirements as required by Task 1.
- o Literature review on molten salt, salt-heated and sodium heated steam generators, and salt-based solar central plants.
- o Preliminary draft of SGS Requirements and Specifications with Sierra Pacific Power Company (SPPC) Fort Churchill Unit #1 selected as the nominal 100-MWe unit from which steam turbine and fossil fuel-fired steam generator data are obtained.
- o Selection of a straight tube, vertical, natural circulation heat exchanger design as the concept which best satisfies the project objectives.
- o Preparation of a Design Analysis Plan.

The final design of the selected concept is presently underway. Future project highlights shall include the following:

- o Conceptual design of a 50-MWe hybrid SGS and a 100-MWe solar stand-alone SGS.
- o Costs estimates for the 50-MWe hybrid and the 100-MWe solar stand-alone SGS's.
- o Fabrication/Erection Plans for the 50-MWe hybrid and the 100-MWe solar stand-alone SGS's.
- o Subsystem Research Experiment (SRE) and Development Plan.
- o Final SGS Requirements and Specifications.
- o Phase 2 Proposal.
- o Final Report.

Selected Concept

Evaluation of candidate steam generator cycles (once through, natural circulation, and forced recirculation), heat exchanger configurations (straight-tube, helical coil, U-tube with common tube sheet, bayonnet tube, hockey stick, serpentine-involute, involute U-tube and U-tube with U-shell) and heat exchanger orientations (vertical, horizontal) resulted in selection of the straight tube, vertical, natural circulation concept. The selected concept is comprised of four heat exchangers (preheater, natural circulation evaporator, superheater and reheater designed to generate the following:



Milestone	Description of Event
1, 3, 5, 6, 7, 9, 11, 14, 16	Monthly Reports
2	Preliminary SGS Requirements and Specifications
4	Design Analysis Plan
8	Steam Generator Fabrication/Erection Plans
10	SRE and Development Plan
12	Final SGS Requirements and Specifications
13	Phase 2 Proposal
15	Draft Final Report
17	Final Report

Figure 1. Project Schedule

	100-MWe Solar Stand-Alone kg/s (lb/h)	50-MWe Hybrid kg/s (lb/h)
Superheated Steam [541°C (1005°F) and 13.48 MPa gage (1955 lb/in^{2}g)]	96.3 (764,000)	48.1 (382,000)
Reheat Steam [541°C (1005°F) and 3.21 MPa gage (465 lb/in^{2}g)]	83.3 (661,000)	41.6 (330,500)

The physical arrangement of each subsystem is identical except for the variation in size resulting from the difference in thermal rating. Figure 2 schematically illustrates the SGS for the 100-MWe solar stand-alone design and Figure 3 shows its arrangement.

Hot molten salt entering the system at 563°C (1045°F) flows in parallel through the superheater and reheater, combines, and passes in series through the evaporator and preheater; cold salt leaves the preheater at approximately 288°C (550°F). All heat exchangers are oriented vertically with all heated steam/water flowing upward. The preheater, superheater, and reheater are counterflow; the evaporator is parallel flow to improve natural circulation. An integral vertical steam drum is mounted atop the evaporator. A drum water recirculation pump is provided to maintain the feedwater at a temperature above the salt freezing point [221°C (430°F)] during start-up and part-load operation. A cold salt recirculation pump is also provided to control the salt temperature entering the subsystem during unit start-up and shutdown.

Final main steam temperature is controlled by a valve at the superheater outlet which controls the salt flow rate through the superheater. Saturated steam from the steam drum is bypassed to the superheater outlet for trim control. Reheat steam temperature is controlled by a valve at the reheater outlet which controls the salt flow rate through the reheater. A spray attemperator is located at the reheater steam inlet for trim control. The quantity of steam generated is determined by the salt flow rate and temperature entering the evaporator. A salt line which bypasses hot salt around the superheater and reheater to the evaporator is used for this purpose.

The heat exchangers are single pass shell-and-tube exchangers, each with a floating head and triple-segmental baffles. An expansion bellows welded to the lower shell head and the steam/water inlet nozzle permits differential expansion between the tube bundle and shell.

Figure 4 illustrates the conceptual design of the preheater, superheater, and reheater. Hot salt enters a nozzle located in the exchanger shell and passes through the annular space formed by a shroud that surrounds the tube bundle. The salt then flows through distribution slots in the shroud, passes over the tube bundle, re-enters the annular space, and flows out of the exchanger through a nozzle in the shell head. Steam/water enter and leave through nozzles in the shell heads. Tie-rods attached to the upper tube-sheet support the triple-segmental baffles, which function as tube-support plates to suppress vibration and buckling. Heat transfer tubes are welded to the face of the tube-sheet using the fillet-type welding technique. Each heat exchanger is vertically hung from a support skirt welded to the steam outlet head.

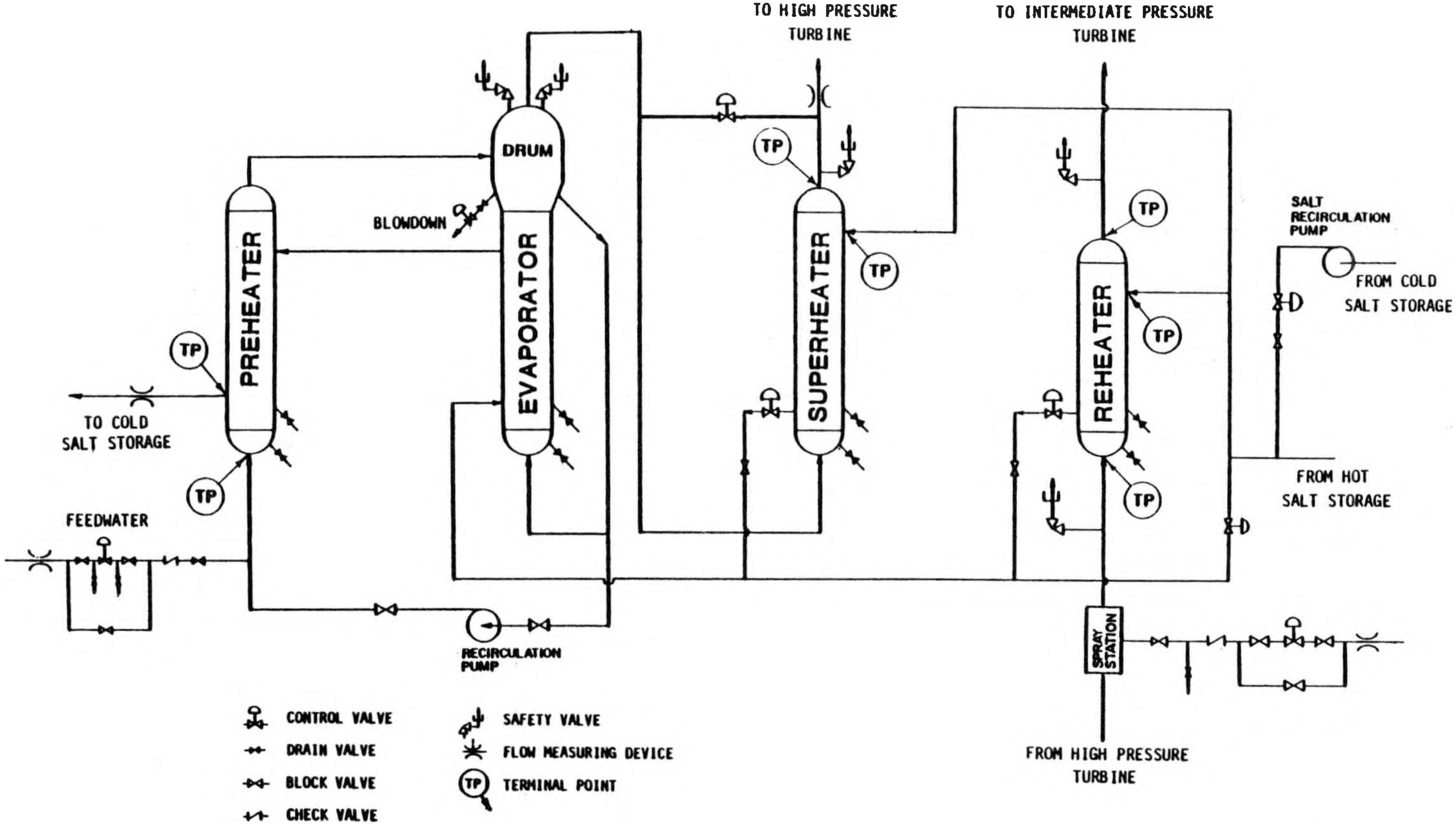


Figure 2. Steam Generator Subsystem Schematic

PRELIMINARY

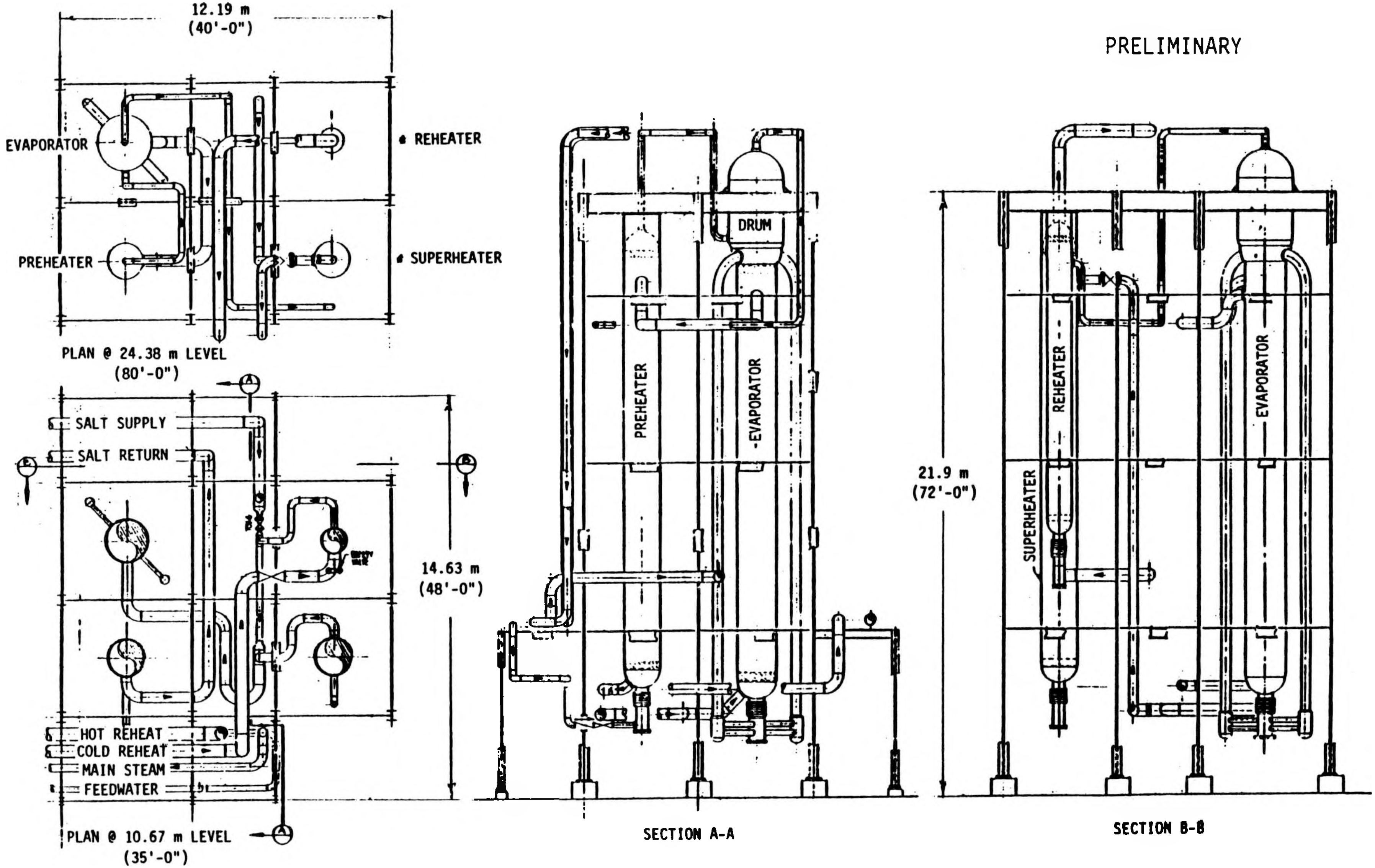
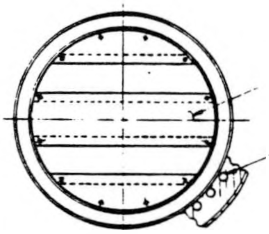


Figure 3. Steam Generator Subsytem Layout



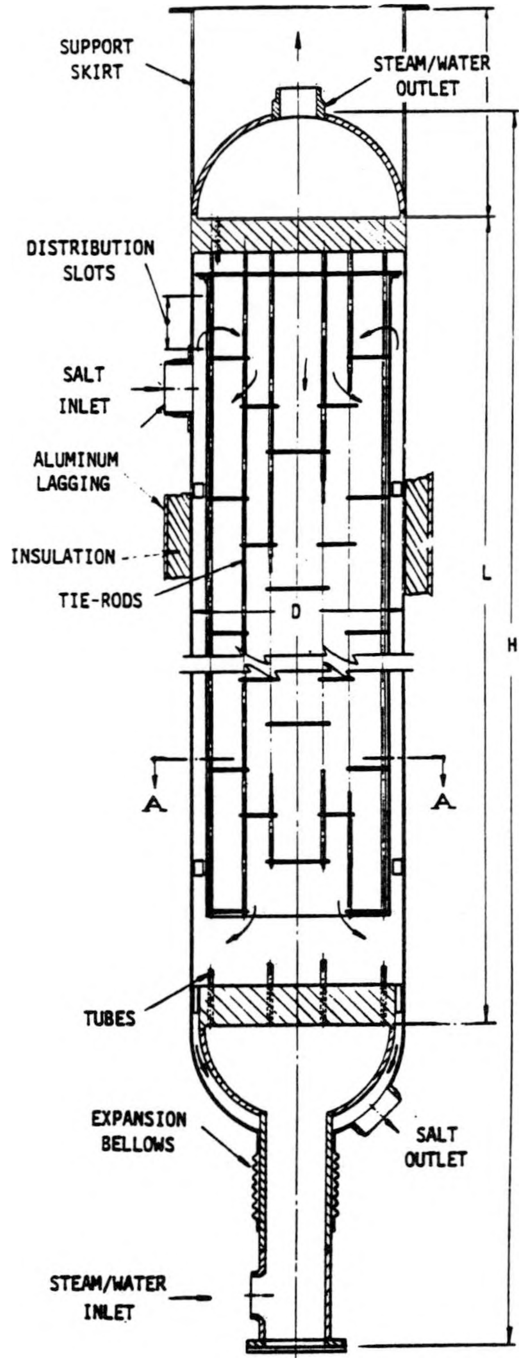
SECTION A-A

50 MW

	PREHEATER	SUPERHEATER	REHEATER
HEIGHT, H	17.83 m (58'-6")	17.83 m (58.6")	13.11 m (43'-0")
TUBE LENGTH, L	15.24 m (50'-0")	15.24 m (50'-0")	10.36 m (34'-0")
SHELL I.D., D	965 mm (3'-2")	787 mm (2'-7")	787 mm (2'-7")
NUMBER OF TUBES	1177	751	949
HEAT TRANSFER SURFACE	895 m^2 (9,630 ft^2)	571 m^2 (6,145 ft^2)	491 m^2 (5,280 ft^2)
TUBE SIZE	15.88 mm O.D. x 1.65 mm min. wall (5/8" O.D. x 0.065" min. wall)		
DESIGN PRESSURE:			
SHELL SIDE	2.07 MPa gage (300 lb/in²g)		
TUBE SIDE	15.51 MPa gage (2250 lb/in²g)	15.34 MPa gage (2225 lb/in²g)	3.96 MPa gage (575 lb/in²g)
DESIGN TEMPERATURE:			
SHELL SIDE	371°C (700°F)	565°C (1050°F)	566°C (1050°F)
TUBE SIDE	371°C (700°F)	566°C (1050°F)	566°C (1050°F)
MATERIALS:			
TUBES FORGINGS SHELL PLATES SHELL HEADS	CS	304SS	304SS

100 MW

	PREHEATER	SUPERHEATER	REHEATER
HEIGHT, H	18.29 m (60'-0")	18.29 m (60'-0")	13.41 m (44'-0")
TUBE LENGTH, L	15.24 m (50'-0")	15.24 m (50'-0")	10.36 m (34'-0")
SHELL I.D., D	1346 mm (4'-5")	1118 mm (3'-8")	1168 mm (3'-10")
NUMBER OF TUBES	2407	1582	[illegible]
HEAT TRANSFER SURFACE	[illegible] m^2 (20,430 ft^2)	1187 m^2 (12,780 ft^2)	1131 m^2 (12,170 ft^2)
TUBE SIZE	15.88 mm O.D. x 1.65 mm min. wall (5/8" O.D. x 0.065" min. wall)		
DESIGN PRESSURE:			
SHELL SIDE	2.07 MPa gage (300 lb/in²g)		
TUBE SIDE	15.51 MPa gage (2250 lb/in²g)	15.34 MPa gage (2225 lb/in²g)	3.96 MPa gage (575 lb/in²g)
DESIGN TEMPERATURE:			
SHELL SIDE	371°C (700°F)	566°C (1050°F)	566°C (1050°F)
TUBE SIDE	371°C (700°F)	566°C (1050°F)	566°C (1050°F)
MATERIALS:			
TUBES FORGINGS SHELL PLATES SHELL HEADS	CS	304SS	304SS
APPLICABLE CODE	ASME SECTION VIII - DIV. 1		



PRELIMINARY

Figure 4. Conceptual Design of Preheater, Superheater, and Reheater

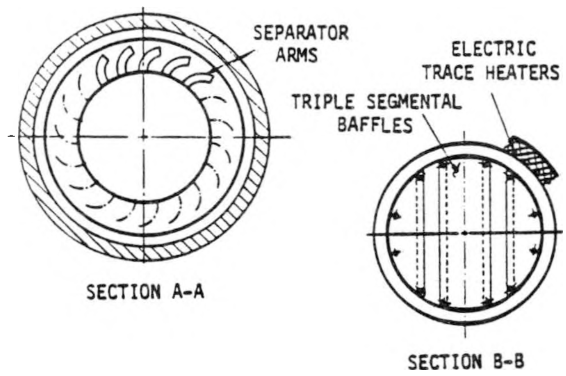
The conceptual design of the natural circulation evaporator is illustrated in Figure 5. The arrangement is similar to the preheater, superheater and reheater, except for the following:

- o Hot salt enters the lower nozzle located in the shell head and leaves through the upper nozzle located in the shell.
- o Steam/water discharge into a vertical steam drum mounted atop the evaporator.
- o Support lugs are provided on the steam drum to hang the evaporator vertically.

The vertical steam drum, which is designed as an integral part of the evaporator, is equipped with spiral arm separators and box type chevron driers to provide dry saturated steam. Feedwater enters the steam drum through a circular distribution pipe positioned below the drum water level. A blowdown line is provided to control impurity concentration levels in the evaporator water.

Electric trace heaters are provided on the heat exchanger shells as well as on all interconnecting salt piping. The trace heaters are sized to preheat and maintain the salt piping and heat exchanger shells at approximately 288°C (550°F). The heat exchangers and all interconnecting piping are insulated with calcium silicate and covered with aluminum lagging.

Safety valves are located on the steam drum, superheater outlet, reheater inlet, and reheater outlet. Pressure-relief devices are located in the inlet and outlet salt piping of each heat exchanger to prevent overpressurization of the shell in the event of a tube rupture.



	50 MW	100 MW
HEIGHT, H	21.03 m (69'-0")	21.79 m (71'-6")
TUBE LENGTH, L	15.24 m (50'-0")	15.24 m (50'-0")
SHELL I.D., D	109 mm (3'-7")	168 m (5'-6")
DRUM I.D., d	1.52 m (5'-0")	2.11 m (6'-11")
SEPARATION ARMS	16	27
CHEVRON DRIERS	9	18
NUMBER OF TUBES	673	1730
HEAT TRANSFER SURFACE	819 m^2 (8810 ft^2)	2104 m^2 (22,646 ft^2)
TUBE SIZE	25.4 mm O.D. x 2.108 mm min. wall (1" O.D. x 0.083" min. wall)	
DESIGN PRESSURE:		
SHELL SIDE	2.07 MPa gage (300 lb/in^2g)	
TUBE SIDE	15.34 MPa gage (2225 lb/in^2g)	
DESIGN TEMPERATURE:		
SHELL SIDE	510°C (950 F)	
TUBE SIDE	371°C (700 F)	
STEAM DRUM	371°C (700 F)	
MATERIALS:		
TUBES, FORGINGS, SHELL PLATES, SHELL HEADS	1% Cr - 1/2% Mo	
APPLICABLE CODE	ASME SECTION VIII - DIV. 1	

PRELIMINARY

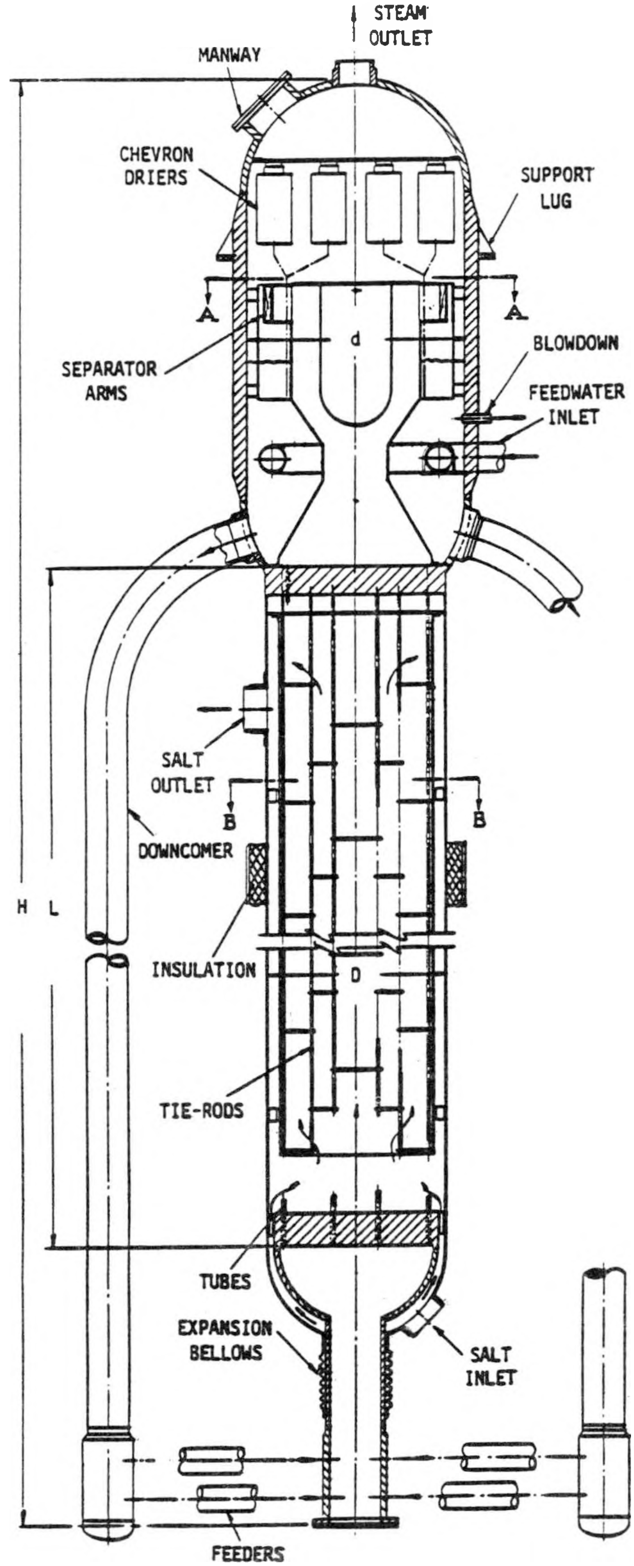


Figure 5. Conceptual Design of Natural Circulation Evaporator

MOLTEN SALT THERMAL ENERGY STORAGE SUBSYSTEM FOR SOLAR THERMAL CENTRAL RECEIVER PLANTS[1]

Philip B. Wells[2]
Martin Marietta Denver Aerospace
Denver, CO 80201

George P. Nassopoulos[3]
American Technigaz, Inc.
Hingham, MA 02043

Abstract

The development of a low cost thermal energy storage subsystem for large solar plants is described. Molten nitrate salt is used as both the solar plant working fluid and the storage medium. The storage system consists of a specially designed hot tank to hold salt at a storage temperature of 839K (1050°F) and a separate carbon steel cold tank to hold the salt after its thermal energy has been extracted to generate steam. The hot tank is lined with insulating firebrick to reduce the shell temperature to 561K (550°F) so that a low-cost carbon steel shell can be used. The internal insulation is protected from the hot salt by a unique metal liner with orthogonal corrugations to allow for numerous cycles of thermal expansion and contraction. This paper describes a preliminary design for a large commercial-size plant (1200 MWh_t), a laboratory test program for the critical components, and the design, construction, and test of a small scale (7 MWh_t) research experiment at the Central Receiver Test Facility in Albuquerque, New Mexico.

Introduction

A wide variety of energy storage subsystems are currently being examined for use with large Solar Thermal Central Receiver (STCR) plants. One of the most attractive of such concepts is the use of a molten nitrate salt (60% $NaNO_3$, 40% KNO_3 by weight) as a sensible heat storage medium. This salt has low cost, high heat capacity per unit volume, low vapor pressure, and good heat transfer properties. Because the salt can also be used as the working fluid in the solar receiver, its use can considerably simplify the solar side of a plant; this enhances reliability and efficiency. The molten salt working temperature limits of approximately 561K (550°F) to 839K (1050°F) are ideally suited to the generation and use of high-pressure, superheated steam for either electrical power generation or industrial process heat applications. Of course, this storage concept can also be used with non-solar heat sources, such as fossil-fired salt heaters, with the same type of advantages.

Under the sponsorship of the Department of Energy and Sandia National Laboratories Livermore, we are conducting a Molten Salt Thermal Energy Storage Subsystem Research Experiment (SRE) program. The objectives of this program are to advance the state of the art in the high temperature containment

[1] Work performed for DOE under Sandia Contract No. 20-2988
[2] Senior Staff Engineer
[3] President

of molten salt, to reduce the costs of thermal energy storage, and to resolve all uncertainties in this storage concept. Our approach is to contain the high temperature salt (839K/1050°F) in a lined and internally insulated hot tank, and to contain the cold salt (561K/550°F) in a separate tank made of carbon steel. The use of internal insulation allows the use of low-cost carbon steel as the shell material for the hot tank. The internal insulation is protected from the salt by a metal liner. The liner is a unique design employing a liquid-tight, waffled membrane of the type used extensively in liquid natural gas (LNG) storage applications. The internal insulation is a low-density insulating firebrick. The hot tank is also externally insulated to reduce heat losses to a minimum. The rest of the system consists of a cold tank (carbon steel with external insulation) and the necessary pumps, sumps, pipes, valves, and controls.

This program consists of the following key elements:

o Preliminary design and cost analysis of a 1200 MWh_t, commercial-size Thermal Energy Storage (TES) subsystem.

o A critical component development program for the liner and internal insulation; this includes numerous fatigue tests of both the liner and the brick, and culminates in the construction and fatigue testing of a laboratory prototype tank of one cubic meter volume with hot salt.

o Design, construction, and testing of a small-scale TES (7 MWh_t), termed a Subsystem Research Experiment (SRE). The SRE will consist of a hot tank, a cold tank, a fossil-fired heater to simulate a solar receiver, an air cooler to simulate a steam generator, and all pumps, sumps, controls, etc. necessary to simulate a complete system.

The SRE will be constructed at the Central Receiver Test Facility (CRTF) at Albuquerque, New Mexico. SRE testing will commence late in 1981. Development testing on the liner and internal insulation was completed in August 1981. The purpose of this paper is to give an overview of the work being performed on this program and the key results obtained to date.

Commercial Storage System

A thermal energy storage (TES) subsystem of this general type consists of the following major components:

- o Hot tank
- o Hot sump and pump
- o Cold tank
- o Cold sump and pump
- o Salt melter and reprocessor
- o Associated piping and valves (heat-traced and insulated)
- o Instrumentation and controls

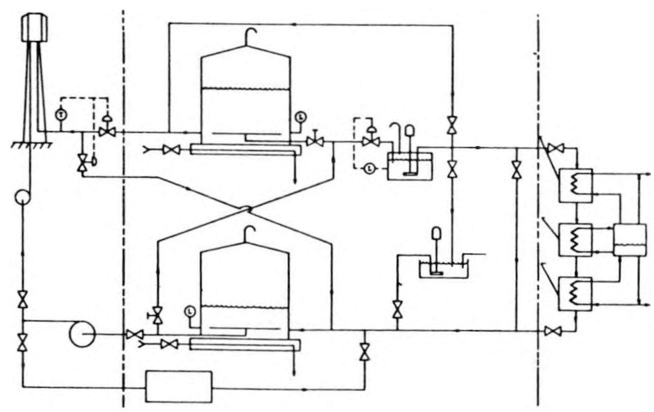


Figure 1 Solar Plant Schematic

In a solar plant, shown schematically in Figure 1, this type of TES would be used in the following way: Salt comes out of the solar receiver at 839K (1050°F) and flows directly into the hot tank. Once the hot tank has been partially filled, hot salt can be removed from it (via the hot sump and pump) and transported to the steam generator. The latter item is a separate subsystem from the TES. Salt leaving the steam generator is at 561K (550°F) and flows directly into the cold tank. Salt can then be taken from the cold tank and pumped up to the receiver on the top of the tower. Note that the solar receiver control strategy is based on controlling the salt outlet temperature by varying the flow rate through the receiver. Thus, the flow rate through the receiver will generally be different from that through the steam generator. This dual tank, sensible heat, thermal storage concept using a single liquid as the heat transfer medium (on both the input and output sides) and as the heat storage medium, has many advantages:

o Low cost due to use of molten nitrate salt and internally insulated hot tank with carbon steel shell.

o Simplified overall plant flow control with a minimum of components.

o Decoupling of steam generating rate from short-term fluctuation in solar insolation.

o Minimum thermal cycling on a specific tank, pump, pipe, etc., owing to use of dual tanks (especially as compared to a thermocline or cascade approach).

An important element in making this approach cost effective is the use of a lined and internally insulated hot tank. Consequently, the emphasis in this program is on the design, development, and testing of a hot tank with a service life of thirty years.

Figure 2 shows our design concept. The Technigaz liner design concept of a waffled metallic membrane was selected for this application because of its great success in cryogenic LNG applications since 1964, and the fact that it was readily adaptable to this molten salt application. A picture of a typical LNG ship tank is shown in Figure 3, and a closeup of the LNG liner is shown in Figure 4. The orthogonal corrugations allow for repeated cycles of thermal expansion and contraction in both directions. The liner acts like a membrane in that it is liquid-tight but does not carry any pressure loads itself--rather, it transmits the loads through the internal insulation into the steel shell. The liner is designed to withstand the cyclic thermal expansion and pressure loads experienced over its thirty year life. Since in a solar plant operation the hot tank would be filled and drained at least once per day, fatigue effects are a major consideration in liner design.

Incoloy 800 was selected as the liner material because of its good strength, corrosion, and fatigue properties in this molten salt environment. This decision was based upon thousands of hours of material test data at 839K (1050°F) in molten salt generated under another solar energy program at Martin Marietta. The liner thickness will be 1.27 mm (0.050 in.), as Incoloy 800 sheets of this thickness can be readily formed with corrugations, the predicted peak stress levels in service are acceptable, and it is close to the customary LNG value of 1.20 mm (0.047 in.) where there is a wealth of liner experience. It is important that the liner be liquid-tight over its service life. A leak would cause salt to flow into the internal insulation and ultimately to the steel shell. If uncorrected, this would obviously cause many problems such as over-temperature of the shell, shell corrosion, increased tank heat loss, permanent damage to the internal insulation, etc. The risk of potential leaks in the liner is reduced to the lowest possible level by leak testing every inch of every weld using an ammonia leak test method, and by extensive fatigue testing at (and above) realistic load levels. In addition, active leak detection methods will be used during solar plant operation so that if a leak should develop, the tank can be shut down and repaired. Personnel safety is provided by a dike around the tank.

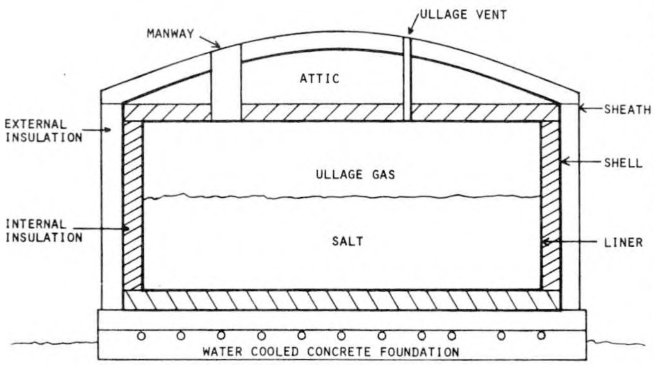


Figure 2 TES Hot Tank Concept

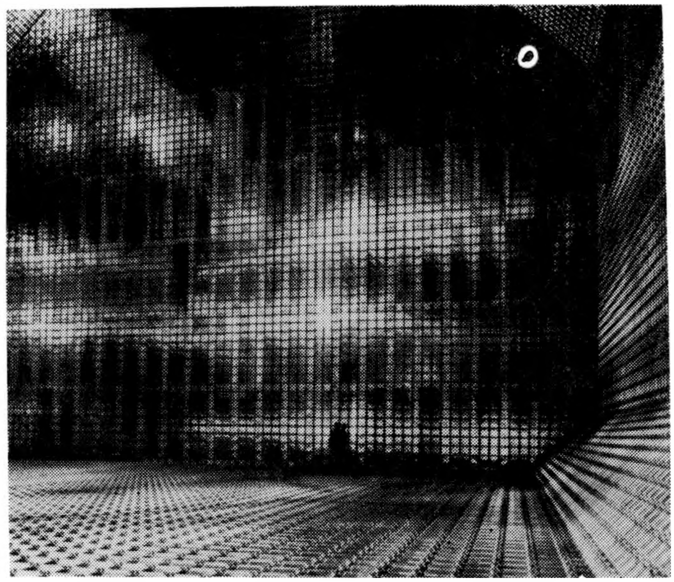


Figure 3 Inside of LNG Storage Tank Onboard Ship

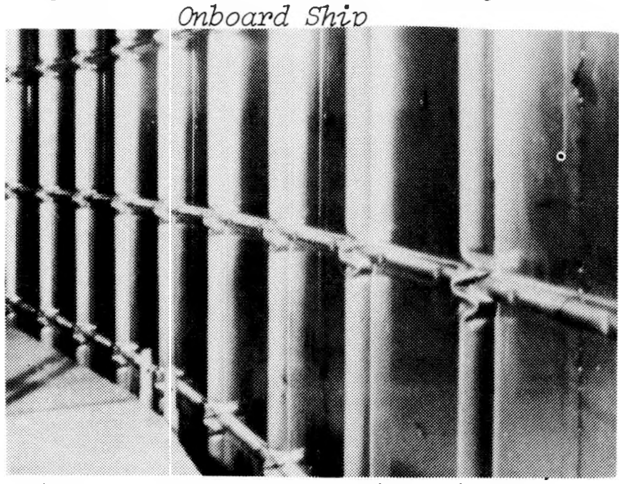


Figure 4 Closeup of Liner in LNG Land Storage Tank

A large number of candidate materials for the internal insulation used on the sidewalls and bottom have been examined. Desired properties of such materials are:

a) Low installed cost,

b) Low thermal conductivity,

c) Adequate strength at elevated temperatures,

d) Thirty-year service life,

c) Compatibility with molten salt for a period of several months in the unlikely event of a leak in the liner.

Examination of these candidates considered such factors as installed cost per unit area, strength tests at elevated temperatures, and tests in molten salt. Based on this work, we selected Johns Manville C22ZSL insulating firebrick. Figure 5 shows the cost tradeoffs involved for this material for our hot tank application. The greater the brick thickness, the less the heat loss from the tank and, therefore, the less the cost of the solar collector system (principally heliostats) required to make up for the lost energy. Our shell temperature design criteria is 561K (550°F), and so the costs of the external insulation necessary to maintain this value are included in this figure. This design temperature was selected because it is below both the API and ASME code values, and because it results in a thermal expansion of the hot tank shell less than (or equal to) that of the cold tank shell.

It can be seen from Figure 5 that the brick thickness for minimum total cost is 0.389 m (15.3 in.). In view of the fact that brick only comes in discrete thicknesses, and that the total cost curve is so flat, we selected a design thickness of 0.343 m (13½ in.). This allows the use of two layers of standard 9 x 4½ x 2½ in. size brick (extra large brick is also available in this thickness but at a cost premium). This brick has undergone extensive testing during this program, including over 4000 hours in molten salt, crush strength tests, creep tests, and fatigue tests, all conducted at 839K (1050 F). All of these test results indicate that this particular brick will be entirely satisfactory for this application. The brick will be installed using mortar and thermal expansion joints every few feet in both directions. Metal shelves will be used to support the brick on the vertical walls. On both the walls and the floor, the liner is attached to the steel shell with rods (called anchor pieces) which run through the brick. Thus, the liner, brick, and shell are intimately coupled both mechanically and thermally.

The internal insulation used on top of the hot tank is a common fibrous insulation. The hot tank also has external insulation, a board (or block) on the top, fibrous on the sides, and a castable on the bottom. The top and sides have weatherproof aluminum sheathing. The sheathing is painted white to reduce diurnal shell temperature variations due to the solar flux. Figure 2 also shows that the hot tank will sit on a water-cooled concrete foundation. Water-cooling was selected so as to ensure that the soil temperature was maintained at (or very near) ambient. This approach avoids the problem area of soil strength and stability at elevated temperatures for long periods of time.

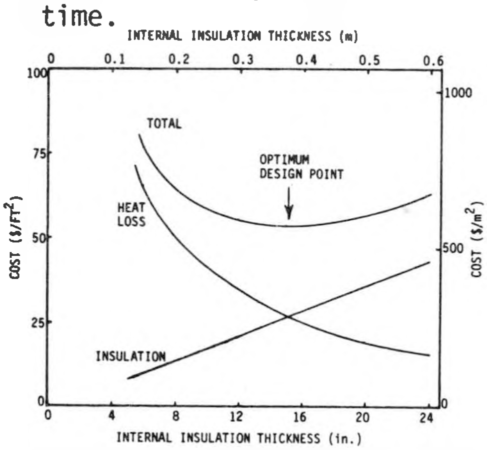


Figure 5 Optimized Insulation Design Methodology

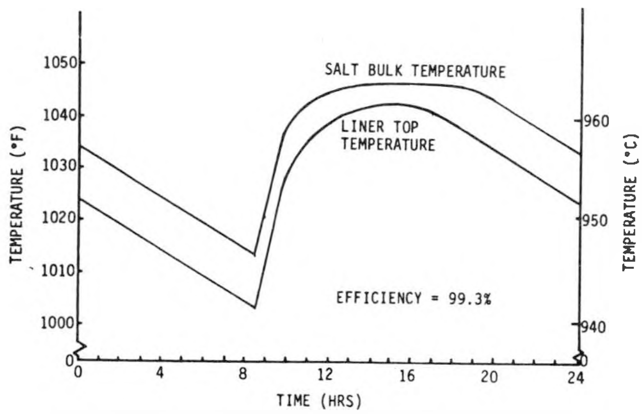


Figure 6 TES Hot Tank Temperature Predictions for Poor Solar Day

The tank shown in Figure 2 will store about 1200 MWh_t of thermal energy, enough to run a 120 MWe steam turbine-generator for approximately four hours. The liner inside diameter is 24.4 m (80 feet), and the inside height is 13.4 m (44 feet). In general, large storage tanks are more cost effective per unit energy stored than smaller ones owing to the reduced area-to-volume ratio. There are, of course, practical limits to how large a single tank can be.

Maximum tank height is generally limited by the allowable soil-bearing strength, unless special foundations are used. We have used a typical value of 0.24 MPa (5000 psf) for this study. Tank height can also be limited by the ability of the liner to withstand the salt pressure; this is currently assessed at about 0.3 MPa (43.5 psi) which corresponds to a salt height of 17.7 m (58.1 ft). Maximum tank diameter is generally limited by the maximum permissible shell thickness without requiring post-weld treatment (3.8 cm/ 1.5 in. in the ASME code) for cost reasons. This limits tank diameters to about 40-46 m (130-150 ft). Cost optimization studies on the hot tank configuration (i.e., height-to-diameter ratio) show that for this 1200 MWh_t capacity, the tank height for precisely minimum cost is 24.5 m (80.3 ft). However, these same studies also show that the cost curve is rather flat, and so the cost penalty for 13.4 m (44 ft) height limitation is only about 3% of the total TES cost.

Figure 6 shows predicted values of the salt bulk temperature versus time for the 1200 MWh_t hot tank in one of many possible usage scenarios. In this particular scenario, the solar plant provides salt into the tank at a variable flow rate but constant temperature (839K/1050°F) between 8.5 and 15.5 hours, at which point the tank is full. The tank is then discharged at 300 MW_t for four hours until it is "empty." The tank is never completely empty in our design approach, since we would always leave a small residual in the tank overnight so as to reduce thermal cycling, avoid the possibility of getting air in the outlet pipes, and prevent freezing of the salt (494K/430°F) in case the sun does not shine for a while. The data of Figure 5 are based on a 0.41 m (16 in.) residual height, which is adequate to satisfy the above objectives (e.g., freezing would not occur for 2-3 weeks). It can be seen that the tank is well-insulated, and that the salt temperature stays high during the time of discharge (15.5 to 19.5 hours). Maximum heat loss rate for this hot tank is 0.38 MW , resulting in less than 0.8% of the maximum storage capacity being lost per day. The liner temperature is only about 3-6K (5-10°F) below the salt temperature due to the high radiative and convective heating rates at these temperatures.

Development Testing

A number of laboratory tests have been conducted on the liner and brick to ensure that they will function properly for the 30 year service life of this system. This research work was very important since Incoloy 800 had never before been used for a liner of this type, and since most previous liner applications have been cryogenic. Also, the JM insulating firebrick had not been used in this manner before. Liner testing began with the formation of 70 liner elements (i.e., small parts of one liner sheet) out of Incoloy 800 using commercial tooling. Knots (the intersection of two orthogonal corrugations) and angle pieces (small right angle pieces used at the corners of a tank) were easily formed and showed good dimensional control, although there was some slight "springback" effect. This was a major milestone in the program since there was some concern about formability with Incoloy 800 as its ductility is considerably lower than that of 304L stainless steel used in LNG applications.

A number of fatigue tests were then performed on these liner elements. The liner is subjected to two types of fatigue loading in service, salt pressure loads due to filling and draining the tank each day and thermal expansion loads. The latter consists of small amplitude diurnal temperature variations (e.g., Figure 5), larger amplitude (but longer frequency) temperature variations due to variations in the weather (such as storms, clouds, etc), and finally complete tank cooldown to ambient temperature for inspection and maintenance. These variations are difficult to quantify in general since they will depend upon solar plant specifics and weather behavior. For the purposes of this study, we have adopted the following design environments:

Fluid pressure: 0-0.3 MPa (43.5 psi) once per day for 30 years

Liner thermal expansion: 700-839K (800-1050°F) once per day for 30 years

The liner was tested in these fatigue environments in a series of tests of ever increasing realism. We began with a set of tests on the small elements described above. Six different kinds of tests were run:

1. Biaxial knot strain tests at room temperature.
2. Uniaxial angle piece strain tests at room temperature.
3. Knot pressure tests at room temperature.
4. Angle piece pressure tests at room temperature.
5. Biaxial knot strain tests at 839K (1050°F).
6. Uniaxial angle piece strain tests at 839K (1050°F).

Each of these strain tests involved 4 different load levels, and 3 or 4 specimens per level. The results of the strain tests on the knots are shown in Figure 7. It can be seen that the fatigue life of the knot is well above the required values. The elevated temperature strain tests gave essentially the same results. The pressure tests were all conducted at 0.3 MPa (43.5 psi) maximum load, and variations in manufacturing tolerances on the wall smoothness were simulated. It was found that there were no through cracks in any of the elements after 150,000 cycles of testing for reasonably smooth walls. An abrupt discontinuity of 2 and 4 mm under one of the feet of a knot reduced the fatigue life to 107,000 and 34,000 cycles respectively. This fatigue testing of liner elements has shown that the liner should withstand the design loads for a number of cycles that far exceeds the requirements for a hot tank at a solar plant.

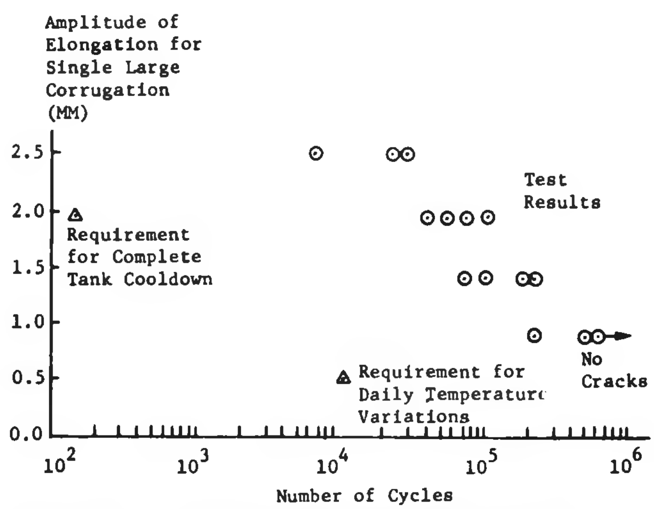


Figure 7 Knot Fatigue Test Results

Considerable testing was also done on the JM C22ZSL brick. This was necessary because even though this brick has been used for years in industry, no data were available on strength or fatigue life at elevated temperatures. The results for testing in air can be summarized as follows:

o The average compression strength is 2.5 MPa (363 psi) with a standard deviation of 0.7 MPa (102 psi) at room temperature, and 2.4 MPa (348 psi) and 0.4 MPa (58 psi) at 839K (1050°F) respectively.

o There is no significant effect of direction, temperature or thermal cycles on compressive strength.

o The brick is undamaged after 145,000 cycles of compressive fatigue testing at applied load levels of 0-0.3 MPa (43.5 psi) or 0-.45 MPa (65.3 psi) at 839K (1050°F), and several samples have survived over 500,000 cycles.

o Brick at 839K (1050°F) has withstood a constant load of 1.0 MPa (150 psi) for 6 months without breaking.

Samples of this brick have also been immersed in molten salt at 839K (1050°F) for 6 months without any catastrophic damage due to chemical attack. These results give confidence that this brick is more than adequate to withstand the loads imposed in this application.

An important part of this development program is the construction and test of a small hot tank which was filled with 839K (1050°F) salt and subjected to cyclic pressure variations. This is called one cubic meter test since that is the interior volume of the tank. This tank was fabricated from large sheets of liner using anchor pieces and welded joints just like a large tank. It also used 0.34 m (13.5 in.) of JM brick, a carbon steel shell and external insulation like a large tank. The test setup and the test levels conformed to the ASME Code (Section III, Appendix II, Article II-1000) for experimental fatigue testing. The basic purpose of this test is to demonstrate that the liner and internal insulation will safely survive the TES environment for the desired service life. This is the only test in the program that will have full scale materials, dimensions, temperatures, pressures, and chemistry as well as a realistic number of pressure cycles.

The tank was exposed to 19,000 pressure cycles with an amplitude of 3 bars (58.1 ft of salt) to simulate a 30 year fatigue life. At the conclusion of the test the tank was emptied and visually inspected using dye penetrant. There was no evidence of any cracks or leaks in the liner. Also, a section of the liner was removed and the brick was inspected. There was no damage to the brick and no salt leakage. The liner was repaired and leak checked to demonstrate repairability of the liner.

Subsystem Research Experiment (SRE)

The largest and most important element of this program is the construction and testing of a thermal energy storage system SRE at the CRTF in Albuquerque, New Mexico. The purpose of this effort is to demonstrate the fabrication techniques and performance characteristics of a lined and internally insulated hot tank, to demonstrate the operation of a complete storage subsystem, and to resolve all uncertainties in this design approach. A flow schematic for the SRE is shown in Figure 8. A 3 MW_t propane fired salt heater will simulate a solar receiver in heating the salt to 839K (1050°F) while a 5 MW_t fan driven air cooler will simulate the action of a steam generator. The SRE hot tank will have inside the liner dimensions of 3.06 m (10.04 ft) diameter and 5.64 m (18' 6") height. This tank has a storage capacity of 7.0 MWh_t. These dimensions are sufficient to allow the use of full scale TES liner panels and insulation thicknesses in the tank construction. The SRE height and diameter are, of course, much smaller than the commercial size TES tank in order to keep the program within an R&D type budget. The height and diameter finally selected were a compromise between full scale simulation and budget considerations.

Construction of the SRE began in June 1981, and testing is expected to commence in the Fall of 1981. The design, construction, salt loading and system startup and checkout are being done using the same type of methods as would be used on a full scale commercial system. The testing will basically consist of performance testing and operational testing. In the former, we will measure the steady state heat loss of each tank at various salt levels and temperatures using electric heaters to maintain constant conditions. We will also measure the transient cooldown. These data will be used to confirm (and improve where necessary) analytical modeling procedures employed in system performance predictions. In the operational tests, utility operators will be employed to simulate how a TES subsystem would be used in the actual solar plants. This will involve daily charging and discharging of each tank. System safety, maintenance and repair procedures will also be demonstrated. It is expected that this storage SRE will be in operation for some time to come, and it is possible that someday it could be connected to a steam generator SRE and/or the molten salt receiver SRE.

As of the end of August 1981, the hot and cold tank shells and foundations have been installed along with the air cooler, gas fired heater, pumps and piping. The internal insulation is being installed in the hot tank and the liner installation will start in September. Other work remaining to be done includes installation of line and tank electrical heaters, installation of instrumentation and controls and the installation of external insulation in the tanks and lines. We plan to start system checkout in November 1981. A photograph of the SRE taken in July 1981 is shown in Figure 9. The hot tank is the higher one and the air cooler is shown in the background.

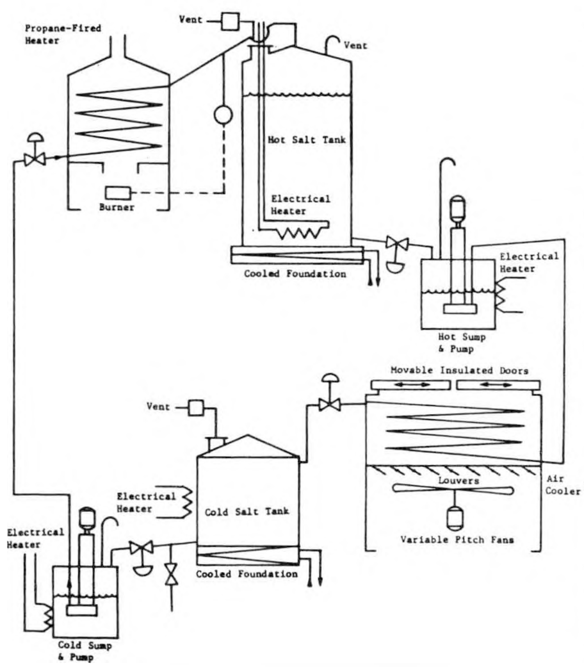


Figure 8 SRE Flow Schematic

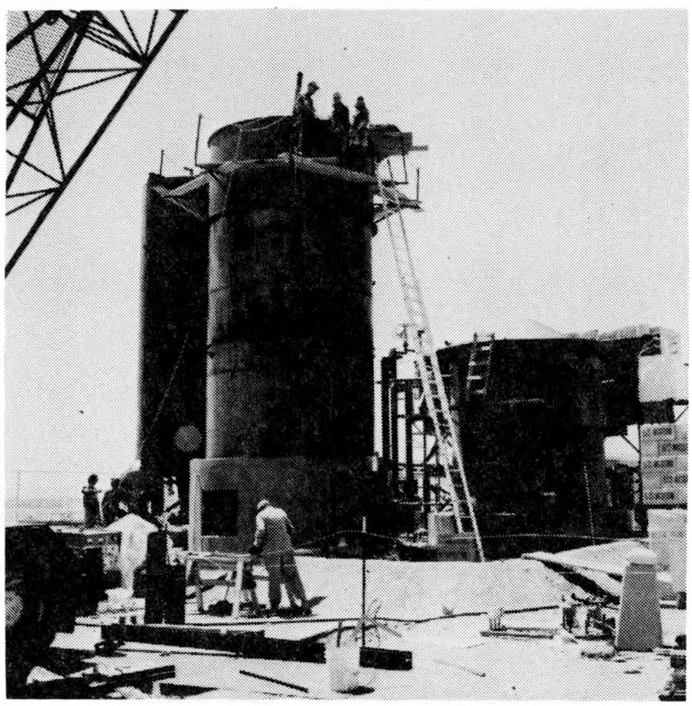


Figure 9 Photo of SRE - July 1981

Conclusions

An intensive development program is underway for a molten salt thermal energy storage system for solar plants. The use of a dual tank approach with a lined and internally insulated hot tank offers many possible advantages. Laboratory testing completed to date indicates that the Incoloy 800 waffled membrane liner and the insulating firebrick insulation are more than strong enough to withstand the loads in a commercial tank for a 30 year service life. Construction is proceeding on a complete storage system SRE at the CRTF in Albuquerque, New Mexico. Testing is planned to start in November 1981.

Acknowledgements

The authors wish to acknowledge the important contributions made to this work by Mr. Tom Tracey, Mr. Owen Scott and Mr. Charles Bolton at Martin Marietta; Mr. Ted Conlon at American Technigaz Inc.; Mr. Charles Zermati and staff at Technigaz S.A.; Mr. Bob Williamson and staff at Stearns-Roger; and Mr. Eric Weber of Arizona Public Service Co.

THE CONVECTIVE LOSS PROGRAM--EXTERNAL RECEIVERS

Dr. Robert J. Moffat
on behalf of
The Stanford/NEAR Program

The objective of this program is to improve the accuracy with which convective losses can be calculated, considering geometries and conditions which are typical of external receivers.

The program is a complicated one, both from the fluid mechanics and the heat transfer standpoints. The geometry is that of a short cylinder, operating at a high temperature, in a cross-wind of unsteady nature. The surface of the cylinder is composed of tubes, forming a two-dimensional roughness, whose "grain" is perpendicular to the convective flow. The heat transfer situation is described as "mixed convection" with the buoyant force orthogonal to the external flow. The sizes are such that the Reynolds numbers and Grashof numbers encountered in the field are beyond the range of the data bank, even for pure forced or pure free convection. There are no data in the literature for the case of mixed convection, for this type of situation--at any values of Reynolds number or Grashof number. Attempts were made to predict the losses for this situation based upon the existing data bank, and using the different methods recommended in the literature. The differences in predicted losses were large enough to have significant effect on the decisions regarding technology development. This program was initiated with the intent of improving the accuracy with which performance predictions could be made.

This program has two parts: an experimental study of mixed convection, and a computer code development. The experiment is being conducted by Nielsen Engineering and Research, Inc. at their facilities in Mountain View, Ca. The computer code development is being done at Stanford University, under a separate but related contract.

The experiment is further subdivided into two parts. The first is a study of mixed convection on a smooth flat plate. This singles out, as much as possible, the buoyancy effect on the forced convection--for which there is no present data at all. This information will provide guidance for the computer modelling and data against which to check the predictions. It will also provide information for the receiver designer who must make less detailed estimates of convective losses in preliminary design studies. The second part of the experiment is a cylinder test to bring together many of the aforementioned effects (i.e., pressure gradient, buoyancy, curvature, roughness, etc.). The cylinder test results will provide data to check the overall validity of the computer code being developed at Stanford.

The program has been underway for approximately 18 months, with funding through Sandia Laboratories.

Progress During the Past Year

A boundary layer code has been written which is capable of dealing with three dimensional boundary layers of the sort expected here: turbulent, variable properties, large differences in temperature, with the body force orthogonal to the free stream velocity. The code has been checked out for laminar boundary layers and awaits implementation of its new turbulence model. This code will be used to test turbulence models against the Nielsen data set.

The overall experiment plan called for two studies: one using a flat plate, to develop the predictive models, and the second using a short cylinder, to document the flow field. Only the flat plate study was involved in the first phase.

During the past year, the experimental apparatus and test piece were designed, built, and put through an extensive series of shakedown and qualification runs. Results from the present study, for pure forced convection and pure free convection, agree with the accepted correlations for those situations within 3-5% over the range of available data. This agreement at the boundaries of the operable domain of the new work supports the believability of the new data in the mixed convection region. Such support is important because there are no other data against which to compare the present work: it must stand or fall on its own provability.

Following the qualification tests, the experiments on mixed convection were conducted. All of the flat plate heat transfer and boundary layer experiments have been finished, the data presentation report has been written, and reviewed, and is now in the final stages of report production.

The heat transfer study consists of measurements of the local heat transfer coefficient at 105 locations on the surface of a hot, vertical, flat plate in a grazing cross-wind. This geometry permits accurate measurement of the effects of the orthogonal body force on the heat transfer. The results will be used to develop methods of modifying existing correlations for heat transfer to account for the new effect, and also for developing entirely new correlation, both integral and differential, for dealing with this situation. The test conditions cover temperatures up to 600°C and velocities up to 6 m/s -- both representative of the actual conditions of use.

The boundary layer study consisted of measurements of the mean velocity, mean temperature, and flow direction within the boundary layer, over the range of conditions used in the heat transfer study.

The experimental facility is shown in Figure 1. The test section is 1.0 m wide and 4.3 m high with an inlet flow system design based on recent NASA studies for the 80 x 120 open-return wind tunnel at the NASA Ames Laboratories. The main structure is wood, with a water-cooled test section

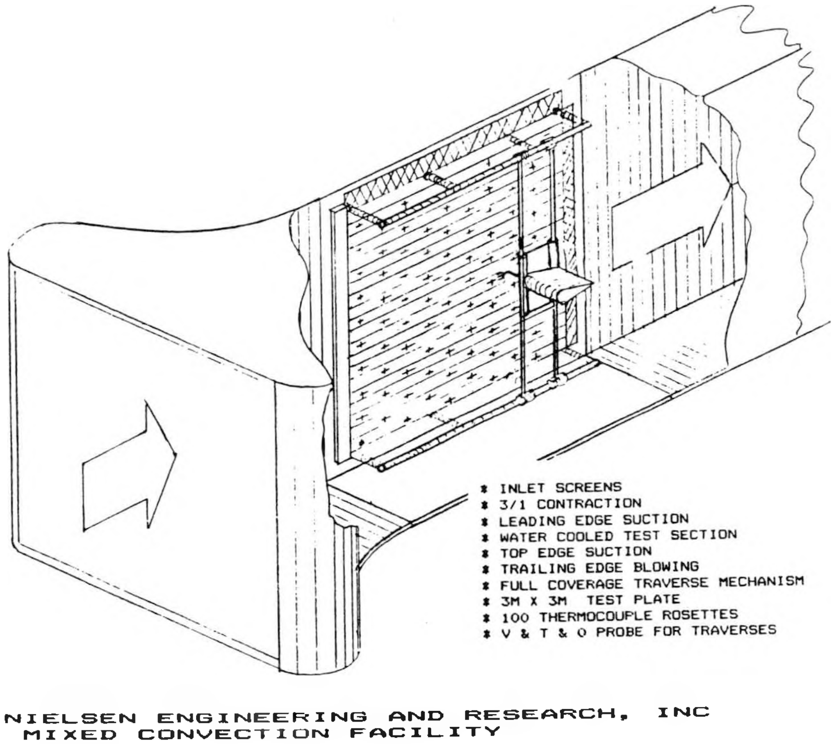


Figure 1. Schematic of the Test Apparatus.

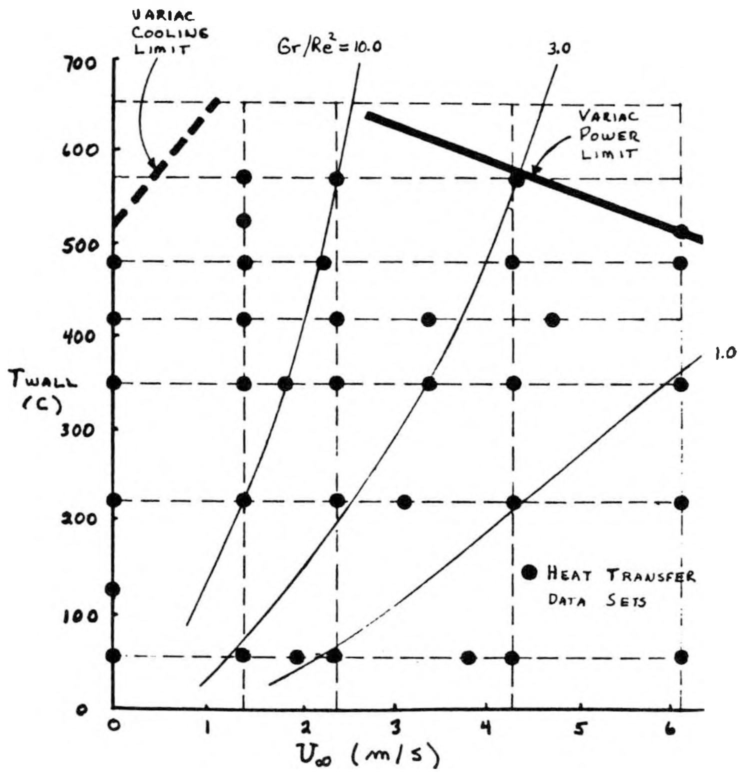


Figure 2. The Operable Domain of the Experiment.

made of steel plate. Tests showed that the flow inside the tunnel was uniform and steady within $\pm$ 0.5% provided that the external wind gusts did not exceed 3 knots. Testing was done between midnight and 10:00 a.m. to take advantage of calm conditions existing then, and to assure high quality flow.

Figure 2 shows the operating domain of the experiments, in velocity vs. temperature coordinates. Three lines are shown, representing ratios of the Grashof number of the Reynolds number (squared) of 10.0, 3.0, and 1.0 as a guide to the different domains. Our results show that mixed convection effects are noticeable, on the mean heat transfer, only between Gr/Re2 = 1.0 and 10.0 -- outside of that domain, the average heat transfer on the surface follows correlations for either pure forced convection (Gr/Re2 < 1.0) or pure free convection (Gr/Re2 > 10.0) . This finding has significant implications for heat transfer predictions and contradicts several of the classical opinions as to how to calculate the combined case.

Heat transfer data were obtained at the 36 locations shown as solid circles on this domain map. These conditions were chosen to cut across the operable domain following lines of constant temperature, lines of constant velocity, and lines of constant ratio of Grashof number of Reynolds number.

At each condition shown on Figure 2, the heat transfer coefficient was measured at 105 locations on the surface of the plate, using an energy balance technique (measuring plate temperature, local electrical heat release, and correcting for secondary heat losses). The data report contains all of the detailed measurements, as well as the significant averages.

The open circles in Figure 2 indicate conditions for which boundary layer traverses were made. At each condition shown, a set of 12 (usually) boundary layer traverses were made, distributed across the face of the plate. Each traverse consisted of 18-22 data points distributed through the boundary layer thickness.

Figure 3 shows an operating surface generated from the heat transfer data from this experiment. The ordinate is the average heat transfer coefficient for the entire plate, the base plane is the velocity-temperature plane. It is possible, using this figure, to find the average value of the heat transfer coefficient for any combination of free stream velocity and wall temperature. Of particular importance are the two plateaus near the forced and free convection boundaries. Within these plateaus, heat transfer can be calculated as though only one effect were present. The domain of noticeable effect of the mixed convection is bounded by Gr/Re2 = 10 and Gr/Re2 = 1.0 .

Figure 4 illustrates a typical set of data, for one of the 36 test conditions. This shows the local value of the Stanton number (h/Gc) over the surface of the plate. The Gr/Re2 value for this conditions was 2.88-- in the middle of the mixed convection region. Note that the transition saddle is parallel to the leading edge of the plate, not skewed as had been expected. This figure is typical of the results obtained. At very high Gr/Re2 , the results resemble pure free convection, at very low Gr/Re2 , the results resemble pure forced convection.

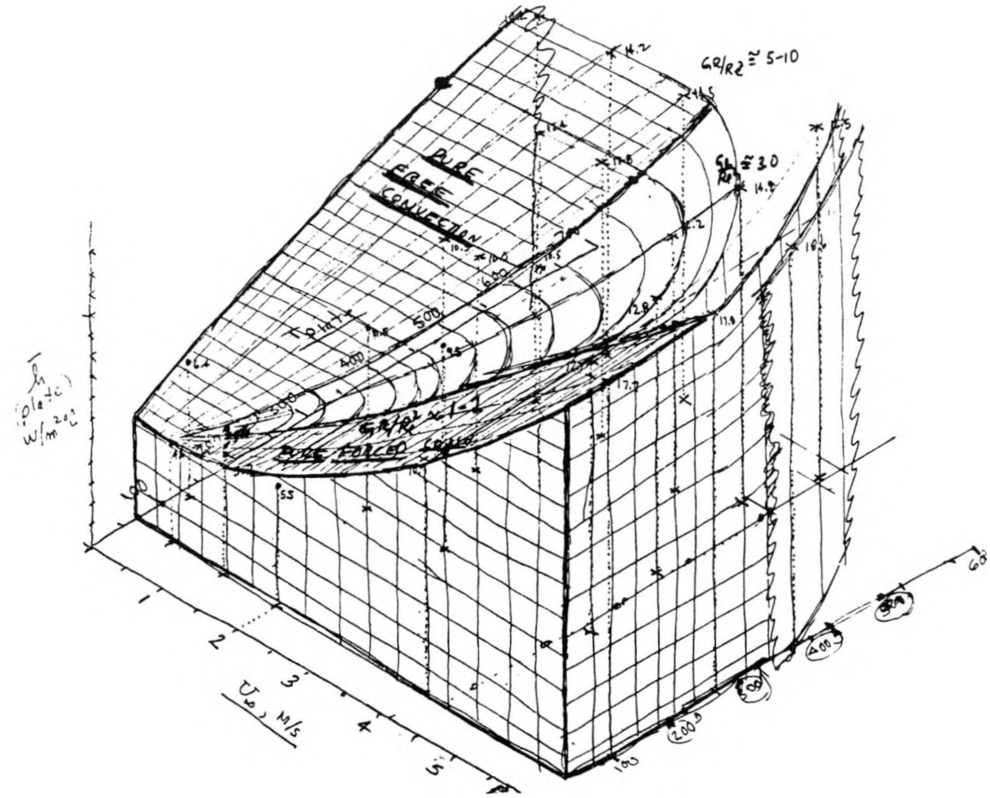


Figure 3. Variation of the Mean Heat Transfer Coefficient with Velocity and Temperature.

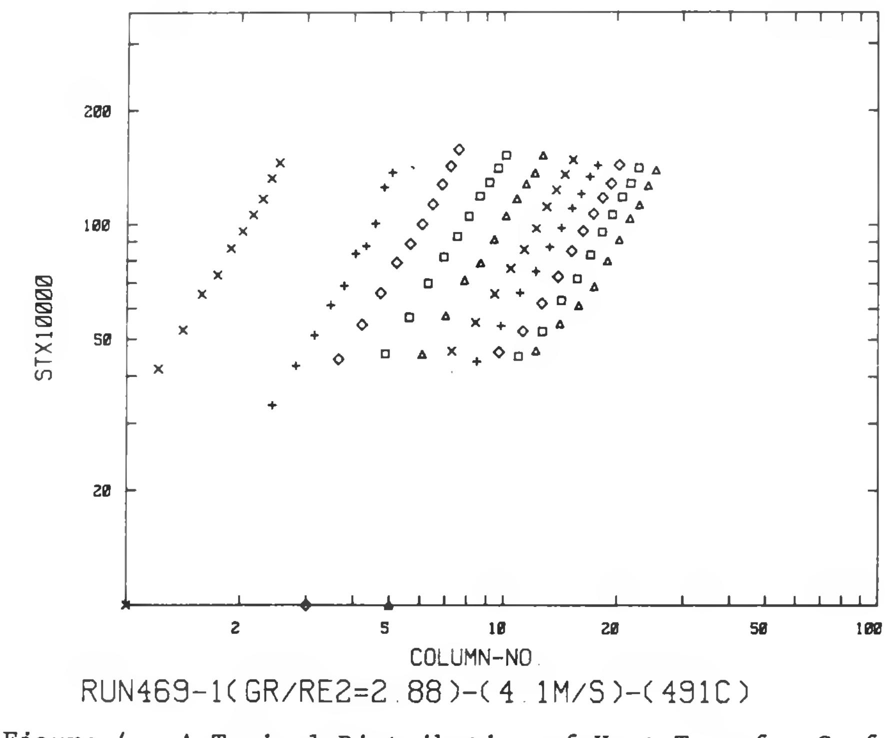


Figure 4. A Typical Distribution of Heat Transfer Coefficients on the Plate at $Gr/Re^2 = 2.88$.

In spite of the fact that the heat transfer seems unaffected by the mixed convection mechanisms except for Gr/Re2 between 1.0 and 10.0 , the boundary layer hydrodynamics are strongly affected, even at very high and very low ratios. For Gr/Re2 less than 1.0, where the heat transfer follows a purely forced convection correlation, the flow in the inner 10% of the boundary layer nevertheless shows a significant upward (i.e., free convection) component. For Gr/Re2 greater than 10.0, where the heat transfer follows a purely free convection correlation, the flow in the inner 10% of the boundary layer shows a significant horizontal (i.e., forced convection) component. Everywhere within the mixed flow region, Gr/Re2 between 1.0 and 10.0 , the flow in the inner 10% of the boundary layer was collateral (i.e., all in the same direction). It has been expected that the velocity would display a smoothly varying direction throughout the layer.

Figure 5 shows the distribution of velocity within a typical boundary layer, at Gr/Re2 of 2.9. The value of w-component is plotted against the value of the u-component. The collateral region appears, in this figure, as the linear region of the w vs. u plot. Note that congruence of the profiles within the upper two-thirds of the plate. These data represent behavior near the trailing edge of the plate, at four different elevations.

Plans for the Next Year

During the coming year, the present data set will be interpreted, and correlations developed to allow the results to be used in guiding future designs.

The Stanford computer code will be loaded with various proposed models of the turbulent transport processes and the predictions compared to the present results.

Further experiments will be conducted, aimed at improving the applicability of these results to predictions around a cylinder under conditions typical of receiver applications.

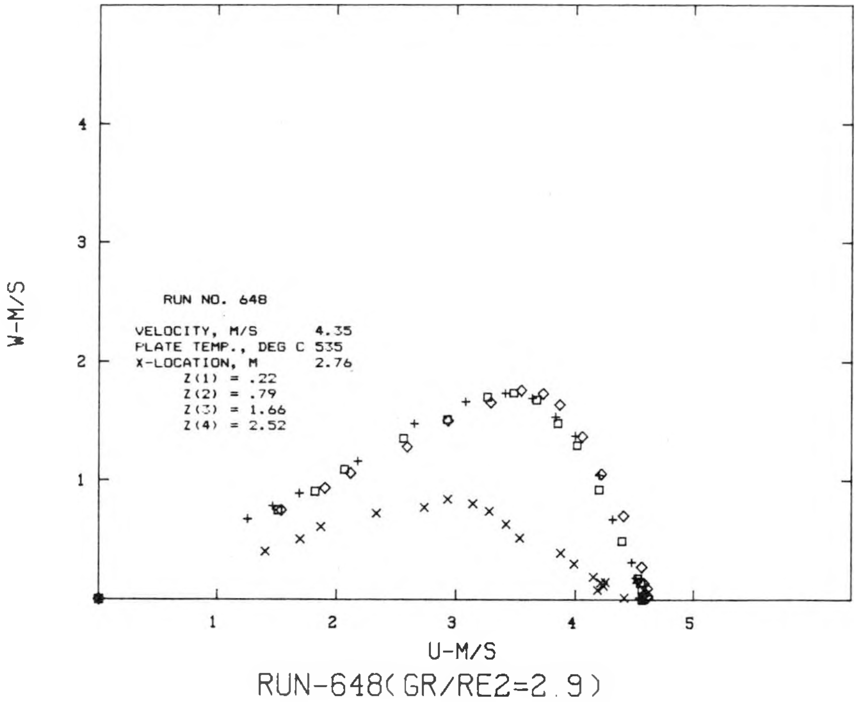


Figure 5. A Typical Plot of the Vertical Versus the Horizontal Component of Velocity within the Boundary Layer, at $Gr/Re^2 = 2.9$.

INVESTIGATION OF FREE-FORCED CONVECTION FLOWS IN CAVITY-TYPE RECEIVERS

J.A.C. Humphrey and F.S. Sherman
Department of Mechanical Engineering
University of California, Berkeley

(Summary of Year Two of Research)

1. Problem Review

Free-forced thermal convection losses from cavity-type solar receivers are a determining factor in establishing their commercial viability. In an early review [1] of the literature it was established that there did not appear to exist, either a useful body of experimental data, or, a theoretical/numerical analysis of the problem, of value for bounding the magnitude and establishing the functional form of these losses.

It has been the purpose of this investigation to bridge part of the gap existing between present knowledge and practical needs. To achieve this the research program has consisted of two parts. The first has as its objective the development of a numerical calculation procedure applicable to cavity-type configurations and flow conditions. The second has as its objective the provision of increased physical insight through flow visualization, and experimental measurements of quantities valuable for the development of the numerical calculation procedure of part one.

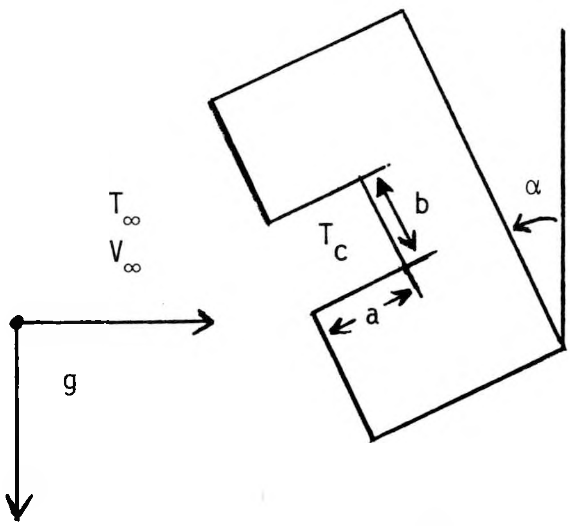
The results of the first year of research have already been reported in [1]. Those corresponding to year two of research are available in the form of a detailed report to Sandia National Laboratories [2]. This communication is essentially a condensed summary of [2].

Although the present investigation has focussed on a configuration which is strongly two-dimensional in the mean flow structure (but turbulent in a truly three-dimensional sense), the extension of the calculation procedure to fully three-dimensional flows is straight forward, albeit laborious.

2. Accomplishments

During year two of research, flow visualization experiments were performed in the free-forced convection regimes for the conditions given in Table 1. Average temperature measurements were taken in the cavity aperture plane for all flow conditions. In the purely free-convection regime

Table 1: Definition of experimental configuration and flow conditions for which visualization and mean temperature profiles have been determined.



$$Re = \frac{b\, V_\infty}{\nu_f}$$

$$Gr = \frac{g\, b^3\, (T_c - T_\infty)}{T_\infty\, \nu_f^2}$$

$$\theta = \frac{T_c - T_\infty}{T_\infty}$$

$$T_f = \frac{T_c + T_\infty}{2}$$

Experiments performed for following conditions:

$\theta \simeq 1.2$

$Gr \simeq 5.5 \times 10^6$

$Re \simeq 0,\ 192,\ 430,\ 1240,\ 1890,\ 2710,\ 3950$

$V_\infty \simeq 0,\ 0.07,\ 0.16,\ 0.45,\ 0.69,\ 0.99,\ 1.41$ (m/s)

$a/b = 0.5,\ 1.0,\ 1.46$

$\alpha = 0°,\ 20°,\ 45°$

measurements were also taken in a plane halfway inside the cavity. The apparatus, instrumentation and experimental methodology are described in [1,2]. All the measurements and visualization results are reported in [2].

The total number of temperature profiles corresponding to the tabulated conditions is 70. Flow visualization results corresponding to these conditions have been of considerable value for helping to establish the nature of the cavity flow as a function of experimental conditions. While measurements of the detailed velocity distribution in and about the cavity have not been made*, the temperature profile shapes display a strong dependence on imposed forced flow conditions. Thus, the profiles provide an indirect evidence of fluid mechanical activity of additional value for development and validation of numerical calculation procedures.

Paralleling the experiment, the numerical calculation procedure [2,3] has been developed further to predict forced flow conditions in laminar regime. A selected sample of experimental conditions was completed with the REBUFFS code to establish:

1. That large scale trends in the flow visualization results and temperature measurements are reasonably well reproduced by the calculation procedure.

and to quantify:

2. The degree of discrepancy arising between measurements and calculations of temperature, largely attributable to the presence of turbulent diffusion of heat in the experiment.

In addition to the above a literature review has been completed pertaining to turbulence modeling practices in flows with buoyant effects. The review has shown that the bulk of significant modeling of these flows has been restricted to Boussinesq-approximate equations and high Reynolds number conditions. In the area of chemically reacting (combustion) flows appeal has been made to density weighted forms of transport equations but it renders more difficult the task of modeling several of the correlation terms. Furthermore, comparisons between density weighted and non-weighted (experimental) quantities introduces potential sources of inaccuracy in model validation.

2.1 Discussion of Some Experimental Results

Figure 1 shows a set of average temperature profiles typical of the measurements obtained in the cavity aperture plane. The variable parameter in this set is the Reynolds number (or Gr/Re^2). The profiles show clearly a marked dependence on the externally imposed flow. Especially noteworthy is the appearance of a bulging in the profiles for $0.35 \leq Gr/Re^2 \leq 3.43$. This bulging is a quantitatively reflection of a qualitative observation

*It is one of the tasks of year three of research to obtain measurements of mean velocities and turbulence intensities for conditions of free-convection.

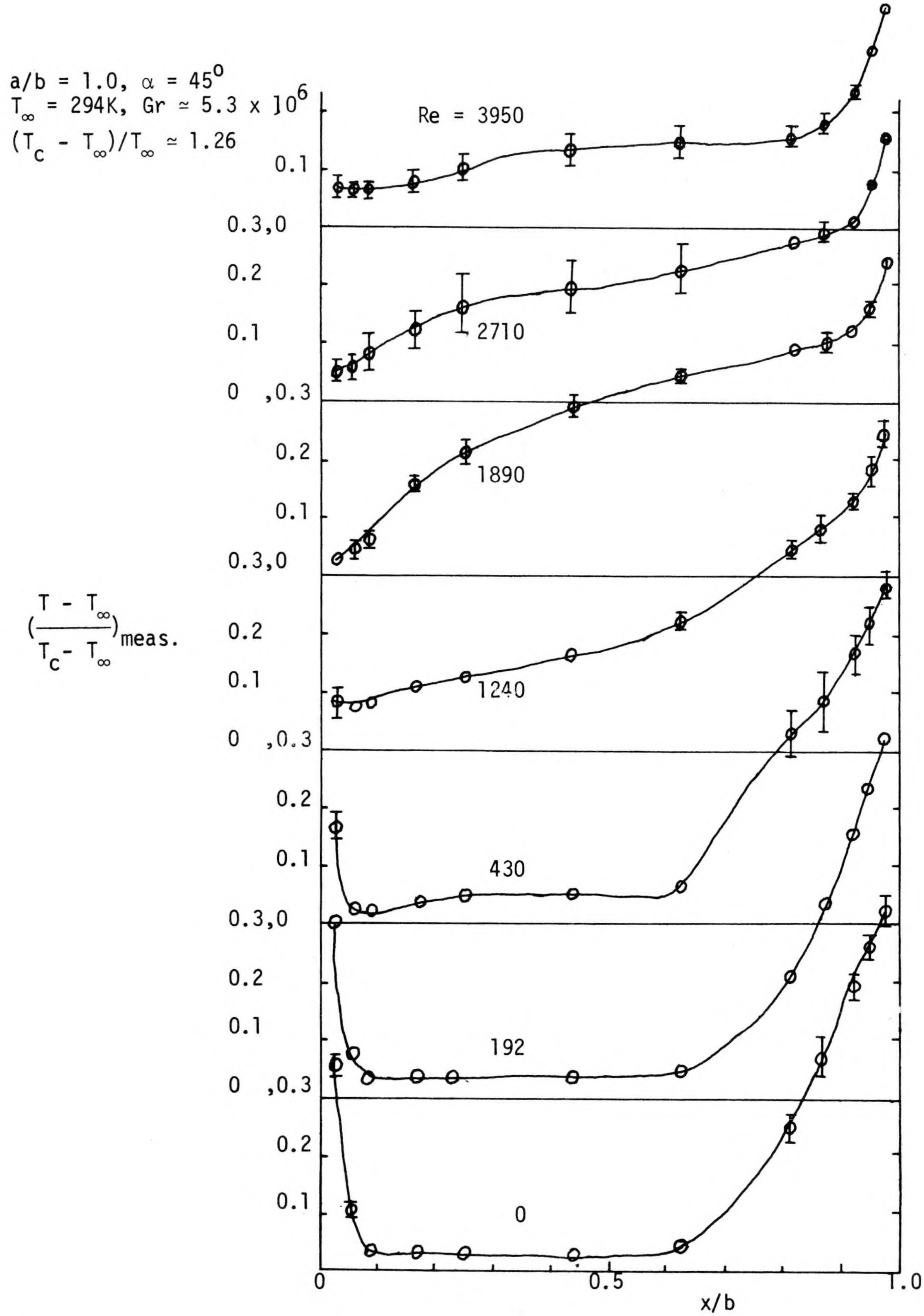


Fig. 1: Aperture plane temperature profiles for conditions shown.

made using the shadowgraph technique. Shadowgraphs showed that for $Gr/Re^2 \leq 5$ the far field flow approaching the cavity was strong enough to overcome and redirect <u>downwards</u> along the aperture plane some hot air emerging from the top of the cavity when the cavity was inclined downward at 20° or 45°. For values of $1 \leq Gr/Re^2 \leq 4$ flow visualization showed that a hot air "bubble" would hover unstably in front of the aperture plane. The size, position and circulation of the bubble were sensitive to fluctuations in the flow induced by buoyancy and possibly by eddy shedding from the apparatus itself. These results suggest, and preliminary calculations appear to confirm, that the development of a hot-air "curtain" in front of the cavity can reduce thermal convective losses.

2.2 Discussion of Some Numerical Calculations

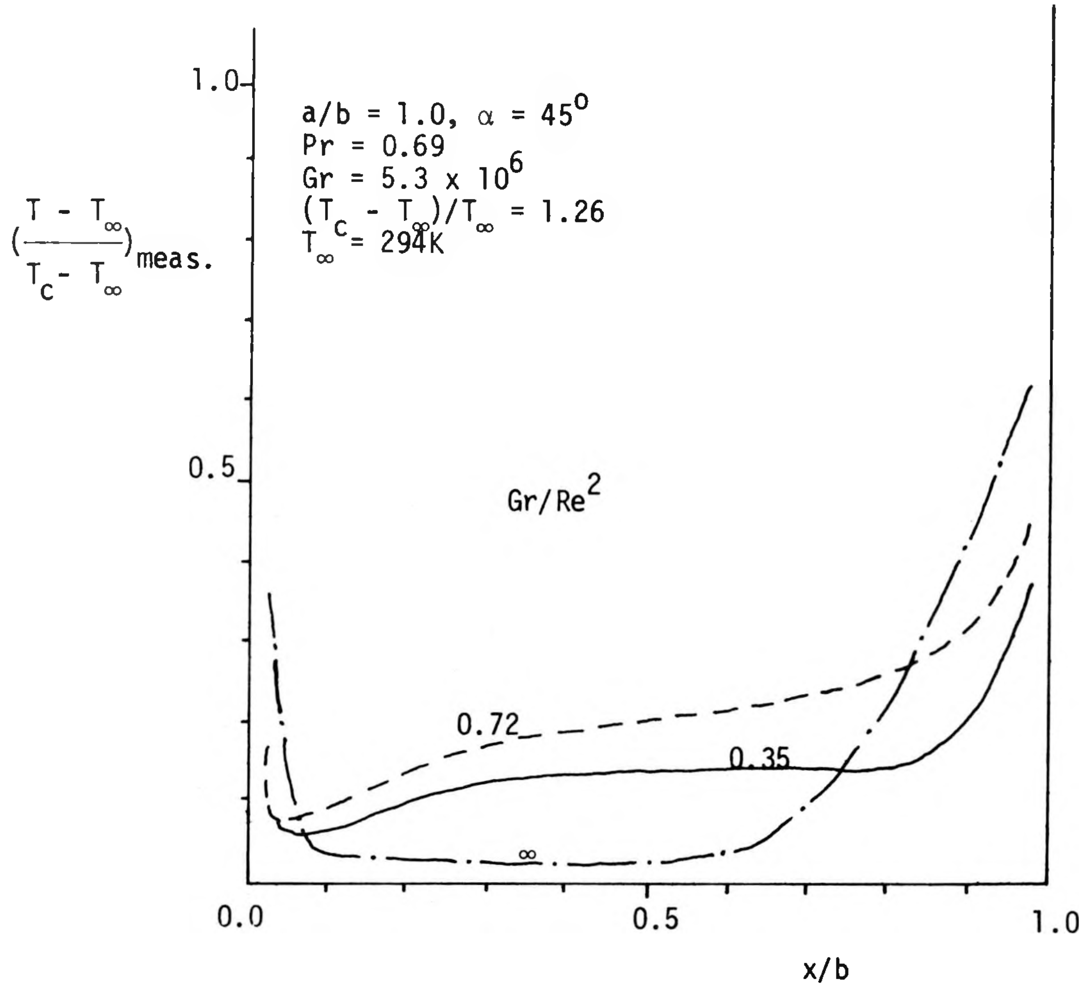
A comparison between selected temperature measurements and corresponding numerical calculations is shown in Figure 2. The calculations were performed assuming laminar flow regime for conditions of the experiment. In general, the qualitative features of the experimental profiles are well reproduced by the calculations although there are some large discrepancies in terms of absolute value. The discrepancies are especially pronounced in regions of the flow (top and bottom walls and corner regions) where turbulent transport of heat can be expected to be large.

Similar levels of agreement were found [2] between measurements and two-equation (k-ε) turbulence model predictions of aperture plane temperature profiles for $a/b = 1$, $\alpha = 45°$, $Gr/Re^2 = 0.35$. For this case inertial contributions to turbulence transport are reasonably well represented by the high Reynolds number (standard) version of the turbulence model used [4]. However, the discrepancies observed, and the increased dominance of buoyancy-driven turbulent transport in regions of the flow where Gr/Re^2 is large, require a substantially improved turbulence modeling practice.

3. Conclusions

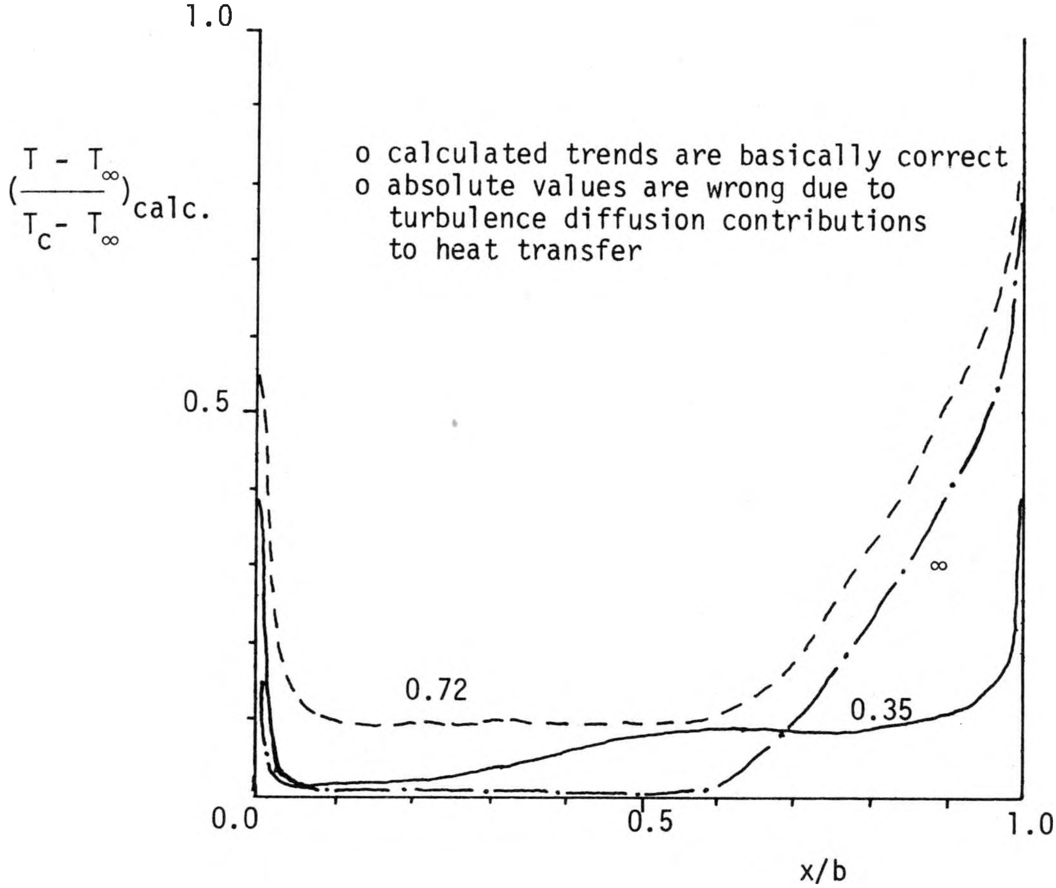
Experimental results from the present two-dimensional investigation and the three-dimensional study being conducted at Sandia National Laboratories, Livermore (summarized elsewhere in this volume [5]) strongly support the notion that turbulent transport of heat represents an important contribution to the overall transport taking place in cavity-type solar receiver geometries. The turbulent transport process is significantly influenced by large fluctuations in body forced which, to date, have not been adequately included in state-of-the-art models of turbulence.

Although laminar and turbulent-regime predictions of selected two-dimensional cavity experiments display encouraging qualitative agreement, an increased accuracy in the calculations requires an improvement of current modeling practices. The measurements and flow visualization results obtained during year two of research will be of great value for achieving such an advancement.



(a)

Fig. 2: Comparison between measured and predicted (laminar regime) aperture plane temperature profiles for conditions shown.



(b)

Fig. 2: Comparison between measured and predicted (laminar regime) aperture plane temperature profiles for conditions of measurements.

4. Plans For Year Three of Research

During the last year of research attention will be focussed on extending the two-equation (k-ε) turbulence model of [6] to flows with strong buoyant effects. Although (to some extent) this has already been done for flows with weak buoyant effects, the results achieved are not sufficiently universal and accurate simultaneously [7-9]. Comparisons will be made between two-dimensional predictions and measurements of selected experimental cases of this investigation before proceeding with an extrapolation to large scale two-dimensional representation of receiver configurations.

The REBUFFS numerical procedure will be extended for predicting three-dimensional flows. It is anticipated that time will allow an extension to the laminar regime only.

Pointwise measurements of velocity and turbulence intensity will be made in the experimental apparatus of this study for conditions of pure free-convection using a laser-Doppler velocimeter. These new results, will further broaden the experimental data bank required for developing, testing and applying new modeling concepts of value for predicting convection losses from heated cavity-type configurations.

References

1. J.A.C. Humphrey, F.S. Sherman, P. Le Quere, K.S. Chen, L. Miller and W.M. To, "Investigation of Free-Forced Convection Flows in Cavity-Type Receivers," SAND 79-8196.

2. J.A.C. Humphrey, F.S. Sherman, K.S. Chen and W.M. To, "Investigation of Free-Forced Convection Flows in Cavity-Type Receivers - Progress Report for year two of Research (1980-1981)," Mechanical Engineering Report No. FM-81-3, University of California, Berkeley, 1981.

3. P. Le Quere, J.A.C. Humphrey and F.S. Sherman, "Numerical Calculation of Thermally Driven Two-Dimensional Unsteady Laminar Flow in Cavities of Rectangular Cross-Section," Numerical Heat Transfer, 4, 249, 1981.

4. B.E. Launder and D.B. Spalding, "The Numerical Computation of Turbulent Flows," Comp. Meths. Appl. Mech. Eng., 3, 269, 1974.

5. J. Kraabel, "An Experimental Investigation of the Convective Heat Losses From Cavity-Type Central Receivers--Some Initial Results," Department of Energy Solar Central Receiver Annual Meeting (October 1981), SAND82-8002.

6. W.P. Jones and B.E. Launder, "The Prediction of Laminarization with a 2-Equation Model of Turbulence," Int. J. Heat Mass Transfer, 15, 301, 1972.

7. O.A. Plumb and L.A. Kennedy, "Application of a k-ε Turbulence Model to Natural Convection from a Vertical Isothermal Surface," JHT, Trans. ASME, 99, 79, 1977.

8. S-J. Lin and S.W. Churchill, "Turbulent Free Convection from a Vertical, Isothermal Plate," Num. Heat Transfer, 1, 129, 1978.

9. M.P. Fraikin, J.J. Portier and C.J. Fraikin, "Application of a k-ε Turbulence Model to an Enclosed Buoyancy Driven Recirculating Flow," Paper 80-HT-68 presented at the Joint ASME/AIChE National Heat Transfer Conference, Orlando, Florida, July 1980.

AN EXPERIMENTAL INVESTIGATION OF THE CONVECTIVE HEAT LOSSES FROM CAVITY-TYPE CENTRAL RECEIVERS - SOME INITIAL RESULTS

J. S. Kraabel
Sandia National Laboratories, Livermore, CA

INTRODUCTION

This paper discusses some of the results of the experimental study of the convective heat losses from cavity-type solar central receivers described in reference 1. The results are for the large cavity experiment operating at full power (517 kW); the geometry is that of a cube, 2.17 m on a side, with one side completely missing. The large size, high power, and high temperature (742°C) are necessary to adequately simulate the losses from a receiver. Results indicate that the convective heat losses are two to three times larger than previously believed possible.

EXPERIMENTAL APPARATUS

The experimental cavity is shown in Figure 1. Peripherals to the experiment include the electrical power controller, the operating console, the instrumentation traverse, and the data acquisition system. A complete description may be found in reference 1.
A traverse is mounted on the exterior building wall in front of the cavity aperture. It is water cooled and provides 3.6 m x 3.6 m x-y motion in a vertical plane 0.6 m in front of the cavity aperture plane. The traverse is a horizontal beam, with an enclosed water channel on the side facing the cavity. In the back of the beam, sheltered from the radiation emitted from the cavity, is a stepping motor which drives the transducer mounting plate in the horizontal or x-direction. The beam is moved in the vertical or y-direction by a stepping motor/ball screw combination on either side. The transducer mounting plate has coolant water and air, mounting space and fasteners for mounting a variety of transducers, thermocouple lead wires and other electrical connections. The operating console is in two sections; one provides for safe operation and monitoring of the cavity and the other provides control of the traverse and instrumentation. A variety of safety interlocks automatically remove power from the controller if water flow is sensed in the fire sprinkler system or if coolant flow to the traverse or power controller is below a set level.

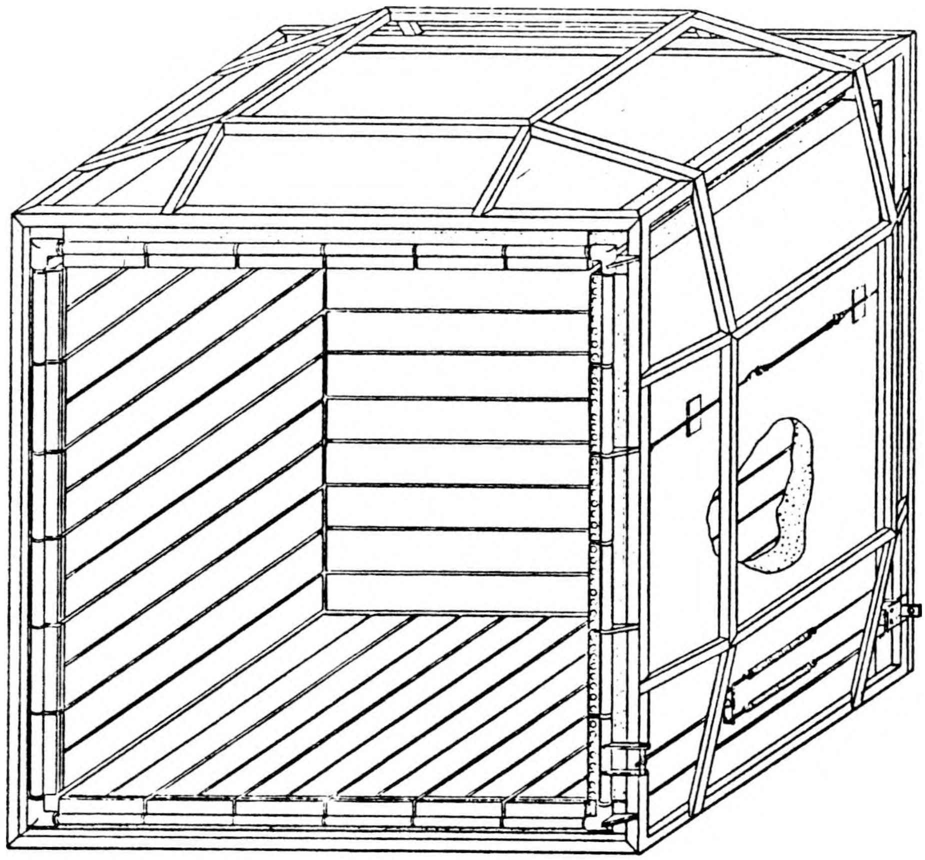


Figure 1. Cavity Isometric, Undercarriage Not Shown

INSTRUMENTATION

Velocity measurements in the aperture plane are made with two different probes. A bi-directional probe developed for building fire studies by NBS[2] is used to obtain directional information of the flow. The probe, which has been used at NBS for velocity measurements under similar conditions to these, yields a pressure difference similar to the difference between total and static pressure. Unlike a pitot-static tube, however, they do not measure a true static pressure and therefore must be calibrated. The probes, built at SNLL, were modified to provide self-cooling. Calibration at NBS showed that both viscous and directional effects were significant. The directional effects limit the usefulness of these probes in this application. They are, however, better suited than pitot-static tubes for determining the qualitative flow patterns such as the location of zero inflow or outflow.

Velocity measurements are made with a pitot-static tube. Calibration at NBS showed no viscous effects at the velocities of interest here and subsequent studies have shown that errors due to angular fluctuations are small. It is emphasized that the calibration included the entire measurement system: probes, pressure transducer, and electronics.

Temperature measurements in the aperture plane are made with a 0.16 cm diameter sheathed type K thermocouple. The sheath is used to increase the response time so that an average temperature measurement is obtained. It is shielded, aspirated, and the sheath and shield are gold-plated to reduce the error arising from the incident radiation to a negligible amount. Studies have shown that the air temperature fluctuations in the aperture are as high as $\pm$ 100°C. The temperature measurement is sampled over a time interval and averaged to find the mean temperature at each measurement location in the aperture.

Radiant heat fluxes are measured with circular foil calorimeters. Calorimeter measurements require correction for convective heat transfer errors. Use of radiometers require correction for limited field-of-view errors which are considered to be more difficult at this time. This instrumentation task has not yet been fully evaluated.

Power levels are determined in three ways. It is measured directly using a two-wattmeter device that uses Hall-effect current transducers to minimize the problems associated with the noisy SCR controlled current. This is the only method suitable for other than full power measurements. The controller measures its output voltage and current. The voltage is between A and B phases and the current is the highest in each of the three legs. The power is then

$$P = \sqrt{3}\, E \cdot I$$

This methods assumes balanced legs and a purely resistive load. The resistances have been measured and are equal to within 0.2%. The value of the resistance, corrected for temperature and the line voltage provides the third power measurement. Agreement between the methods at full power is within 2%.

Surface temperature measurements are obtained by placing sheathed, ungrounded thermocouples between the Inconel heating elements and the insulation. This approach minimizes the problems of electrical noise and high voltage affecting the thermocouple signal or measuring electronics.

RESULTS

The results of the experiment at full power are summarized in table 1.

TABLE 1. Full Power Test Results

Line Voltage	478V
Leg Current	616A
Average Wall Temperature	742C
Ambient Air Temperature	18C
Back Wall Temperature	109C
Power Consumed	517kW
Conduction Losses	
Back Wall	27kW
Bus Bars	10kW
Convection	220kW
Radiation	
Flux Map	257kW
Calculated	254kW
Total Losses	514kW

The convection and the radiation flux map data are derived by integrating aperture maps. The power consumed is the average of the three independent power measurements. The energy balance check of the overall experimental accuracy is found by comparing the total losses with the power consumption. The two values agree well within the uncertainties of the experiment.

FLOW PATTERNS

Although the flow visualization efforts to date have been less than satisfactory, some flow patterns are discernable and it is useful to describe these before discussing the aperture plane results. The largest velocities are those normal to the aperture plane. The flow into the bottom and out of the top of the cavity is the primary flow. The secondary flow becomes visible as shadowgraph patterns on the back wall when a collimated light source is shined into the cavity. The secondary flow pattern appears to be two large vortices, each occupying an upper quadrant of the cavity. The flow on the side walls is vertical; as the flow reaches an upper corner, it turns and flows horizontally along the upper wall or ceiling towards the center. In the center, the opposing flows from each side meet and turn downward. This downward motion as well as the flow towards the center of the top wall cause the bulk of the mass and enthalpy flux to exit the top center of the cavity. Some of the flow up the vertical sides escapes from the cavity along the sides, noticably in the upper corners, but the majority of the flow exits in the top-center of the cavity.

Smoke visualization indicates that the majority of the aperture flow patterns are due to entrainment. The low bulk temperature of the air leaving the cavity tend to confirm this hypothesis. The fluid entering in the bottom 0.3 m or less appears to reach the back wall; all fluid that enters above that is simply entrained into and then out of the cavity.

The flow patterns in the aperture are highly turbulent and appear to have several dominant time scales from 0.1 sec or less to as long as several minutes. Fluctuations in the temperature have been observed as high as 100°C. Velocity fluctuations appear on the order of $\pm$ 0.3 m/s for velocities from 1 to 4 m/s. Characterization of the turbulence is an area of future interest.

APERTURE PLANE RESULTS

The results of measurements in the aperture plane are shown in three-dimensional surface plots. The right, upper axis (hidden) coincides with the upper edge of the aperture; the lower left axis is the lower edge of the cavity.

The temperature difference distributions in the aperture plane (Figure 2) show that the highest temperatures are found in the boundary layer exiting at the top edge of the cavity, and that the highest temperatures in the boundary layer are at the center and then the two corners.

The flow out of the cavity as measured with the pitot-static tube is shown in Figure 3. A bi-directional probe was used to determine the location of zero net outflow. The pitot-static tube, which is less sensitive to errors caused by the fluctuations in velocity or in direction, was then used to measure the outflow velocities. It was not used to measure inflow, however. The same characteristics as temperature are apparent here: the velocities are greatest in the boundary layer, especially in the center and the corners. Inflow velocities measured with the bi-directional probe were approximately uniform at 1.0 m/s. The mass flux, shown in Figure 4, shows that the bulk of the flow exits the top-center of the cavity. This is in qualitative agreement with the velocity data and means that the velocities are high enough in the center to override the decrease in local density due to the increased temperatures in the top-center.

The enthalpy flux, shown in Figure 5, should then be no surprise. The trends evident throughout are even more amplified because the enthalpy is the product of the mass flux and temperature distributions. It is gratifying to observe that the combination of the measurement of the fluctuating products result in a smooth enthalpy surface.

The surface is a weighted spline fit of the data; the weighting factors at each point are the inverse of the standard deviation of the data at that point. The curve is then integrated to determine the convective losses. The entire procedure results in a stable number that has been averaged during the measurement of each quantity, during the combination with each other, and finally, spatially over the aperture plane. The resultant 2σ uncertainty due to the unsteady nature of the flow is estimated to be 2.4%

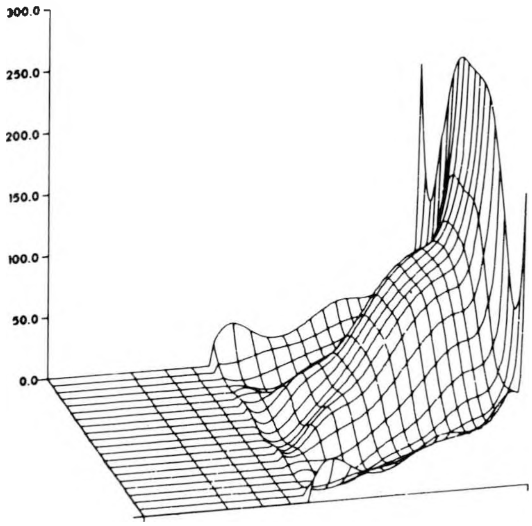


Figure 2. Temperature
Distribution, °C.

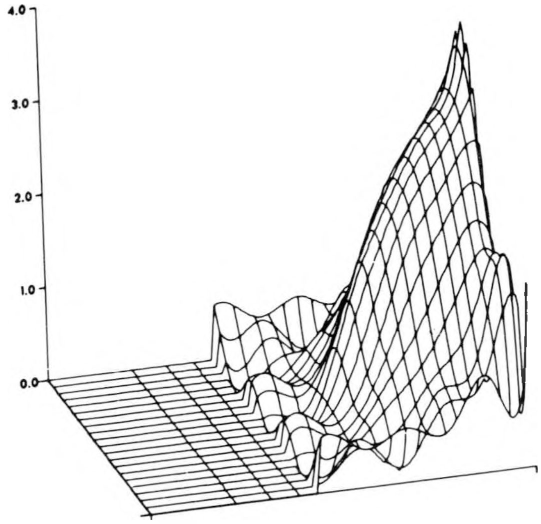


Figure 3. Velocity
Distribution, m/s.

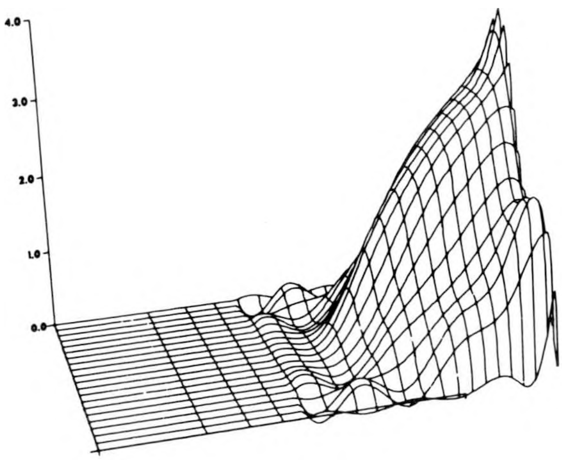


Figure 4. Mass Flux
Distribution, kg/s-m^2.

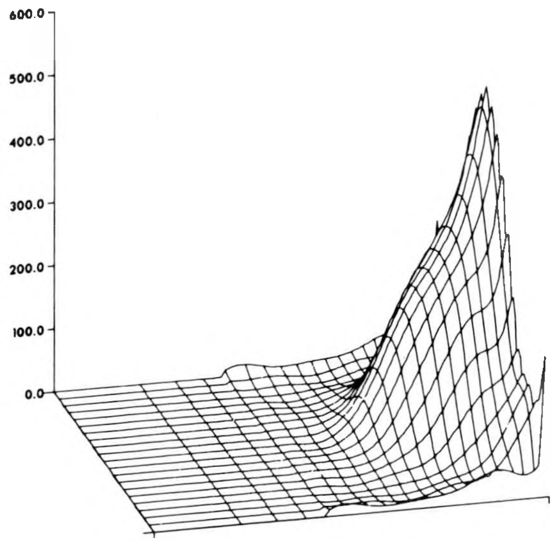


Figure 5. Enthalpy Flux,
kW/m^2.

Conclusion

Results to date show the flow patterns in the large cavity experiment are complex and highly turbulent. The geometry, the high temperature of the surfaces, and the large size of the experiment contribute to the enhanced heat transfer in a manner that has yet to be fully understood. Efforts in the following year will concentrate on determining the causal relationships between these parameters.

REFERENCES

1. J. S. Kraabel, "Large Cavity Energy Loss Experiment," DOE Solar Central Receiver Semi-annual Meeting, Jan. 1981, SAND80-8049.

2. B. J. McCaffrey, G. Heskestad, "A Robust Bidirectional Low-Velocity Probe for Flame and Fire Application," Combustion and Flame, Vol. 26, 1976.

Technical Overview of the DOE Heliostat Development Program

Clayton L. Mavis
Sandia National Laboratories, Livermore

This overview presents the major activities in the heliostat development program for FY81 as well as the planned activities for FY82.

Accomplishments in FY81

Evaluations of the second-generation heliostats and the heliostats for the 10 MW_e Solar Central Receiver Pilot Plant received major emphasis in FY81 and will continue to do so in FY82.

Second-Generation Heliostats

Second-generation heliostat contracts were completed by: ARCO Power Systems, Boeing Engineering and Construction, Martin Marietta Corporation, and McDonnell Douglas Astronautics Company. Each contractor provided two prototype heliostats (Figures 1 and 2), a detailed design for a production heliostat, a conceptual design for a factory that would produce 50,000 heliostats per year, and cost estimates; these cost estimates were for a users' cost (price) and included production costs, installation, operation, and maintenance costs. The installed-heliostat cost estimates indicate that the heliostat cost goal can be met at relatively low production rates after a few years of production.

Testing of the heliostat prototypes was performed by each of the contractors at their respective plants and by Sandia National Laboratories at the Central Receiver Test Facility (CRTF). The test criteria is outlined in Table I.

The results of the evaluation show that there are four viable second-generation heliostat designs. Unique approaches to the same generic design have eliminated the inherent design weaknesses of previous designs. However, some relatively low-risk design changes could benefit all four of the designs.

Development reports from each of the contractors have been published. A public presentation of the results of Sandia's evaluation was made on September 30 and October 1, 1981, in Albuquerque, New Mexico. The evaluation results will be published early in FY82.

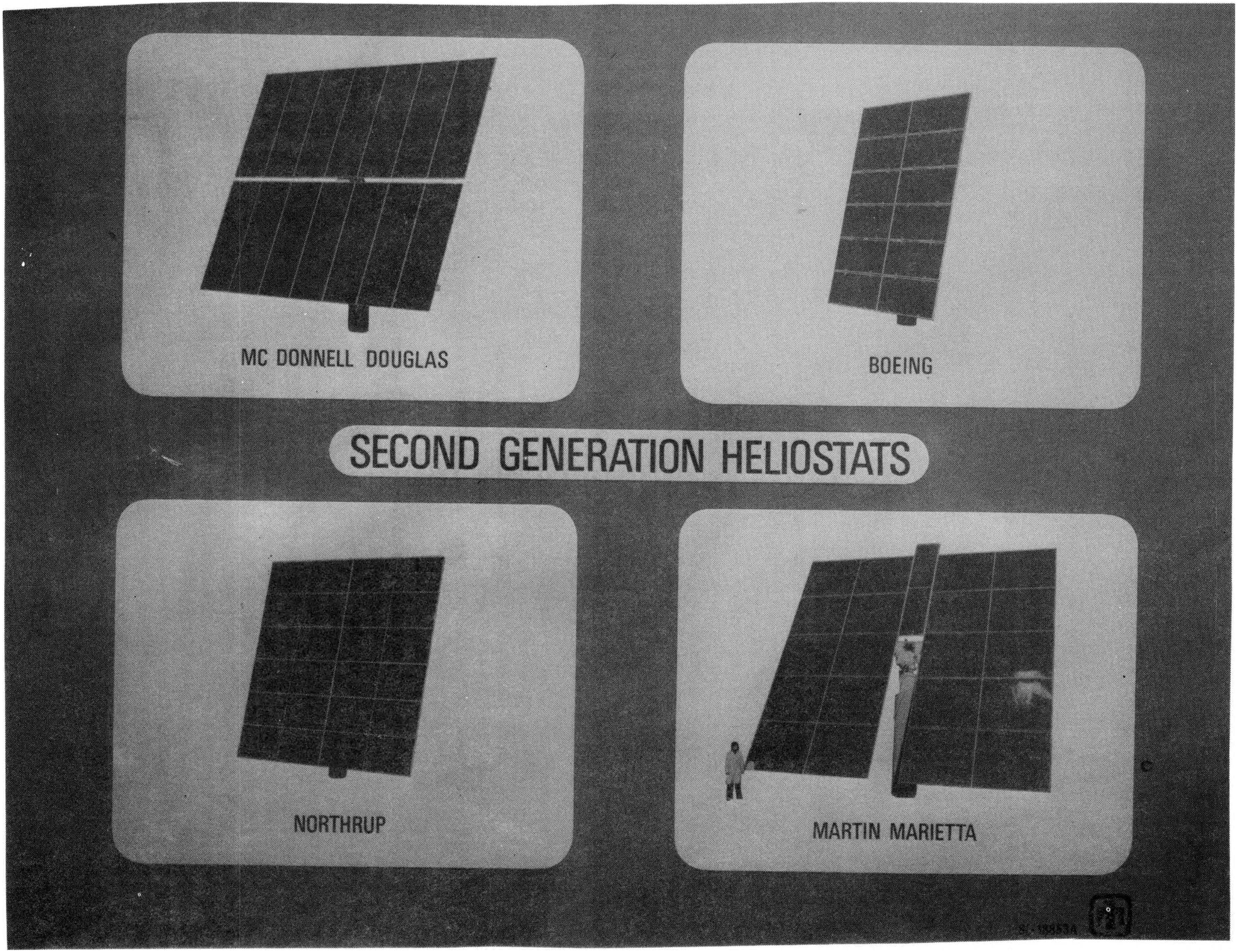


Figure 1 - Frontal Photographs of Second Generation Heliostats

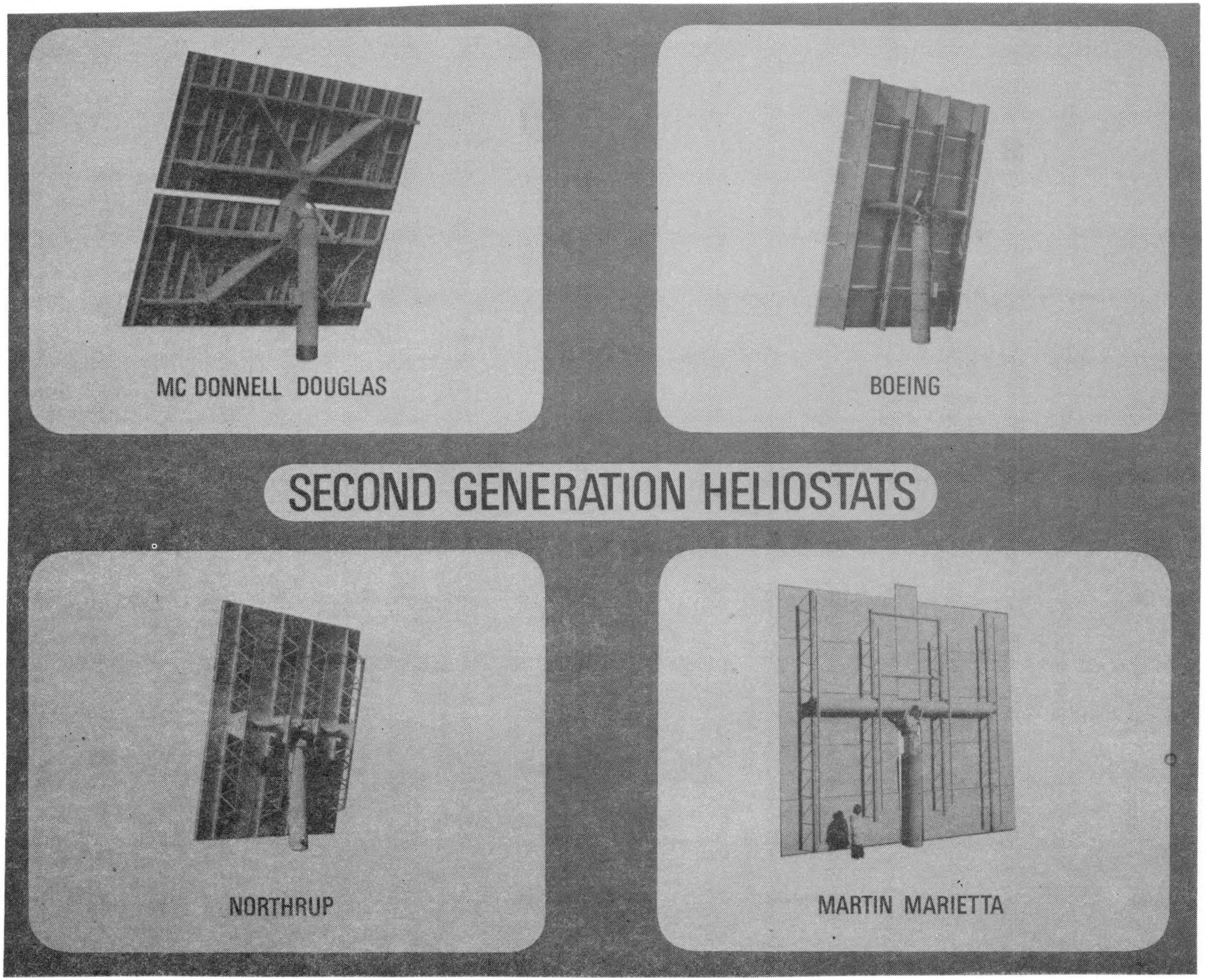


Figure 2 - Backview Photographs of Second Generation Heliostats

Table I

Test Criteria

Operational	Performance	Survival	Lifetime
•Modes Track Slew Reference Position Limits Singularity Resolution •Power Required •Operation Under Wind Load	•Tracking Accuracy No Wind Maximum Wind •Beam Quality (1) •Mirror Quality Waviness Contour Reflectivity Glass Stress •Structural Deflections •HELIOS(2) Analysis	•Wind Loads •Hail •Cold Water •Snow and Ice	•Accelerated Cycling •Thermal Cycling •Glass Stress •1-Year Operation

(1) Beam quality is the heliostat reflected beam iso-flux contour containing 90 percent of the reflected power.
(2) HELIOS is a heliostat performance analysis computer code which calculates beam quality.

10 MW_e Solar Central Receiver Pilot Plant Heliostats

Installation of 1818 heliostats at the pilot plant near Barstow, California, was another major accomplishment in FY81. Testing and analysis at Martin Marietta and Sandia identified several production process and design problems which were overcome and the installation was completed on schedule. The major problems were:

Design Problems	Solutions
Low Drive Strength Under 90 mph Wind Loads	Stow heliostat in favorable orientation to reduce loads on drive train.
Heliostat Controller Functional Problems	Change grounding
Lightning Damage	Ground signal cable rodent shield (not completed)

Production process development was accomplished for mirror module sealing and bonding and for fabrication of bonding tools.

Analysis of the pilot plant heliostat control strategy for heliostat beam safety verified that there should be no safety problems. The development of a new computer code for beam safety analysis allowed new control strategies to be identified.

Other FY81 Activities

Investigations were also underway in FY81 to develop new methods for evaluating heliostat performance, to develop methods to clean heliostats, and to evaluate materials for plastic-enclosed heliostats. New mirror module concepts and a rotating heliostat field were pursued as well. These activities are summarized below:

Prevention of Soiling - Springborn Laboratories

- Coating for glass and plastics reduces soiling rates
- Dirt accumulates after multiple washing with high-pressure water
- Additional testing required
- Final report was published

Enclosed Heliostat Materials Development

- Boeing
- General Electric
- DSET Testing
- Real-time and accelerated testing of KYNAR show that 30-year life may be possible
- Contracts started for further development

Heliostat Performance/Requirements Optimization

- Contracts started in July, 1981, with:
  - Martin Marietta
  - McDonnell Douglas
- Determine second-generation heliostat cost reductions resulting from:
  - designing for survival vs. performance
  - less-accurate heliostats for some portion of the field
- Determine cost impact of higher maximum wind speeds
- Identify design codes applicable to heliostats

Computer Codes

- Heliostat foundation design
  - EPRI/Sandia contract with GAI Consultants, Inc.
  - Report available early in FY82

- Heliostat cost analysis tool - Sandia
  - standard format for cost comparisons
  - convenient framework for sensitivity studies
  - detailed profit center cost allocation
  - explicit model for burden, tax, and profit
  - report available by December, 1981

- Heliostat beam safety - Sandia
  - calculates flux on horizontal plane above heliostat field
  - identifies contributing heliostats
  - keeps track of rate laggards and heliostats at limit switches
  - report to be published

Instrumentation - Sandia

- Heliostat characterization system

  TV camera at target identifies:
  - canting errors
  - slope errors

- Portable reflectometer
- Mirror module contour measurement tool
- Sand abrasion vs. wind speed and particle size

New Concepts

- Rotating heliostat field - Stilson Associates
  - field performance
  - cost estimates

- First surface mirror - Westinghouse
  - TiO_2 overcoat on silver
  - samples fabricated
  - laboratory testing

- Stressed membrane mirrors - Sandia
  - concept studies conducted
  - light in weight
  - air pressure provides focus/defocus
  - lightweight microglass or plastic reflector required

Improved Heliostat Mirror Modules

- Boeing - laminated glass, no adhesives
- Martin Marietta - redesigned second-generation
- McDonnell Douglas - improved second-generation
- ARCO Power Systems - second-generation design

Field Testing Planned

- CRTF
- Barstow
- Livermore

Activities in FY82

Heliostat development activities at Sandia have been reorganized for FY82. Sandia, Albuquerque, will pursue all new heliostat development; Sandia, Livermore, will complete existing development activities and continue evaluation of the pilot plant heliostats. These FY82 activities are shown below:

<u>Sandia, Livermore</u>

- Publish second-generation heliostat evaluation reports
- Complete heliostat performance/requirements optimization contracts
- Complete rotating heliostat field study contract
- Refine heliostat characterization system
- Evaluate pilot plant heliostats
- Install second-generation heliostats at the pilot plant

<u>Sandia, Albuquerque</u>

- Initiate all new heliostat development activities

  Resolution of budgetary constraints is required before new development activities can be identified.

ARCO POWER SYSTEMS SECOND GENERATION HELIOSTAT

Floyd A. Blake
ARCO Power Systems
Littleton, Colorado

Contract Title: "Second Generation Heliostat Development for Solar Central Receiver Systems"

Contract No.: Sandia 83-2729E

Objectives

Design, Manufacture, and test Second Generation Heliostat designed for high volume production.

Accomplishments of Past 12 Months:

1. Installation and test of three prototype heliostats at ARCO/Northrup test facility, Hutchins, Texas.

2. Installation and competitive test of two contract deliverable heliostats at CRTF, Albuquerque, NM.

Contract is complete - Final report published.

The ARCO II heliostat features (1) a central pile pedestal, (2) a dual axis planetary/worm gear drive, (3) a torque tube-truss structural rack, (4) a "floating mirror" metal sandwich mirror module, and (5) microprocessor controlled stepper motors. Basic parameters are shown in Table I. The normal mirror mounting presents an uninterrupted "full face" except for minimal installation clearance as shown in Figure 1. The structure, drive, and pedestal installation details are shown in Figure 2.

Constant attention to high volume production requirements included use of design features to minimize shipping bulk. Figure 3 illustrates the compact packaging of the heliostat. Field assembly is planned and was repeatedly accomplished in less than 4 hours from this "kit" configuration during the contractual program.

Mirror Module

The mirror module design uses all steel sandwich structure fabricated from 26 gage galvannealed sheet as illustrated in Figure 4. The glass mirror is not bonded to the substrate, but adheres to it via a thin layer of silicon grease. This floating bond overcomes thermal curvature problems encountered in conventionally bonded metal to glass modules while maintaining hail protection properties.

Drive Unit

The drive unit is a fully sealed dual axis drive designed by Winsmith for the ARCO II heliostat. The drive features identical gearing in both the azimuth and elevation sections. Each is a two stage system using a 460:1 planetary input stage and a 40:1 worm output stage for a combined 18400:1 ratio. Housings for both sections are cast iron, as is the output worm gear. Major characteristics of the drive are shown in Figure 5.

Structure

The mirror support rack, shown being installed in Figure 6 is a welded structure of commercially produced building trusses and a torque tube flanged to mate with the elevation gear. Right and left hand assemblies are identical and therefore interchangeable.

The central support pedestal is a straight pipe-like steel pile flanged to interface with the azimuth gear housing. A cut out at chest height enables insertion of the electronics modules used for stepper motor control.

Control

Open loop control is accomplished by microprocessor control of stepper motors mounted on the planetary stage housings of the drive. Off-the-shelf motors and translators were used together with the unique heliostat control electronics module.

Future

Development of the ARCO heliostat is continuing under internal support. Improvements identified during the test and post test analysis phase of the program have been incorporated into the Hutchins or Albuquerque heliostats as noted in Table 2. Testing of these features is underway and those beneficial to performance, producibility or cost will be incorporated into the models planned for near term field installation.

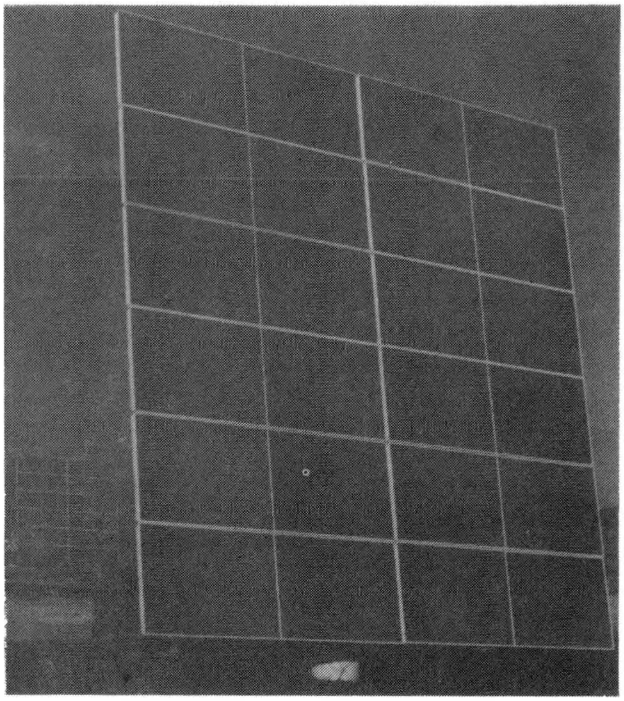


Figure I: Both ARCO Heliostats at CRTF, Tracking

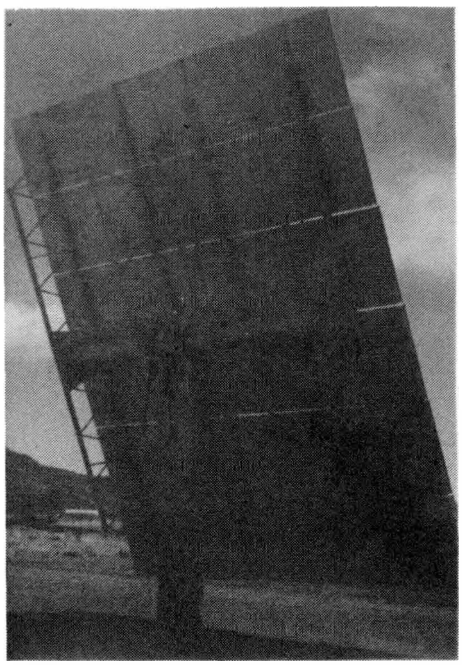


Figure 2: CRTF No. I Heliostat, Rear View, Tracking

Major Features of ARCO Heliostat

Configuration	= Dual Axis Tracking, Pedestal Drive Mount
Area	= 52.8 sq.m (568 sq.ft)
Height	= 7.44 m (24.42 ft)
Width	= 7.37 m (24.19 ft)
Stow Positions	= Normal, Vertical, 60 E of S
	High Winds, Horizontal Face Up
Mirror Module	
Mirror	= 4 ft x 12 ft x .094 in, 2nd surf silvered glass
Substrate	= 28 ga. Steel Face and Back Sheet Sandwich
Bond	= Dow #4 Silicone Grease
Mounting	= 3 point
Drive	= 18400:1 Ratio Azimuth-Elevation Gear System
Input Stage	= 460:1 Planetary
Output Stage	= 40:1 Worm
Electronics	= HC Logic, Pwr Supply, Stepper Translators
Motors	= Superior M112 Stepper Motors
Control	= Single Computer with I/O to HC Logic
Structure	
Stationary	= 24 in Dia Steel Pipe Pedestal
Tracking	= 2 Double 29.5 in Truss Racks

Table I: Major Features of ARCO Heliostat

Continuing Development Since End of 'Second Generation Program'

Face Down Stowage- #2 Hutchins Heliostat
Discontinued Due to Cost and Operation Impacts

DC Motor Drive
On Test Nos 1 & 3 Hutchins Heliostats

Integral Bearing Drive
On Test No 1 Hutchins Heliostat

Mirror Module
Two Alternative Configurations On Test
No. 2 Hutchins Heliostat

Software Tilt Compensation
Incorporated and Tested at CRTF

Table 2: Continuing Development since end of "Second Generation" Program

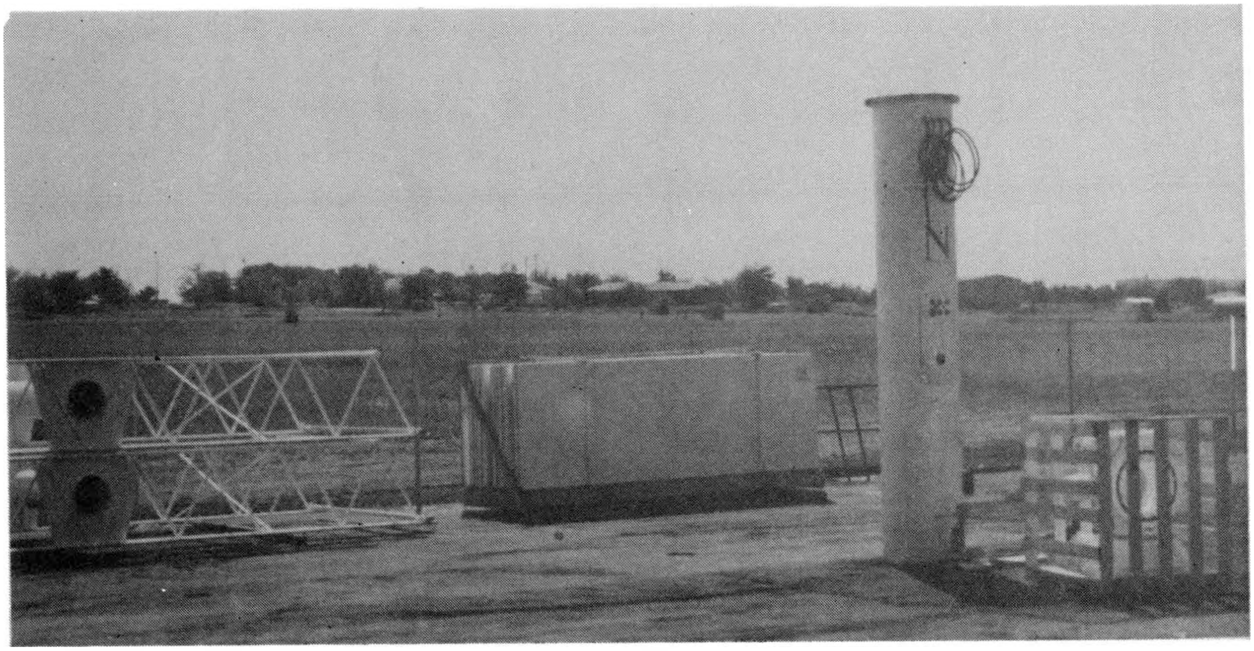


Figure 3: Heliostat Kit: Rack Structure, Mirror Module Pallet, Pedestal, and Drive

Features of ARCO Mirror Module

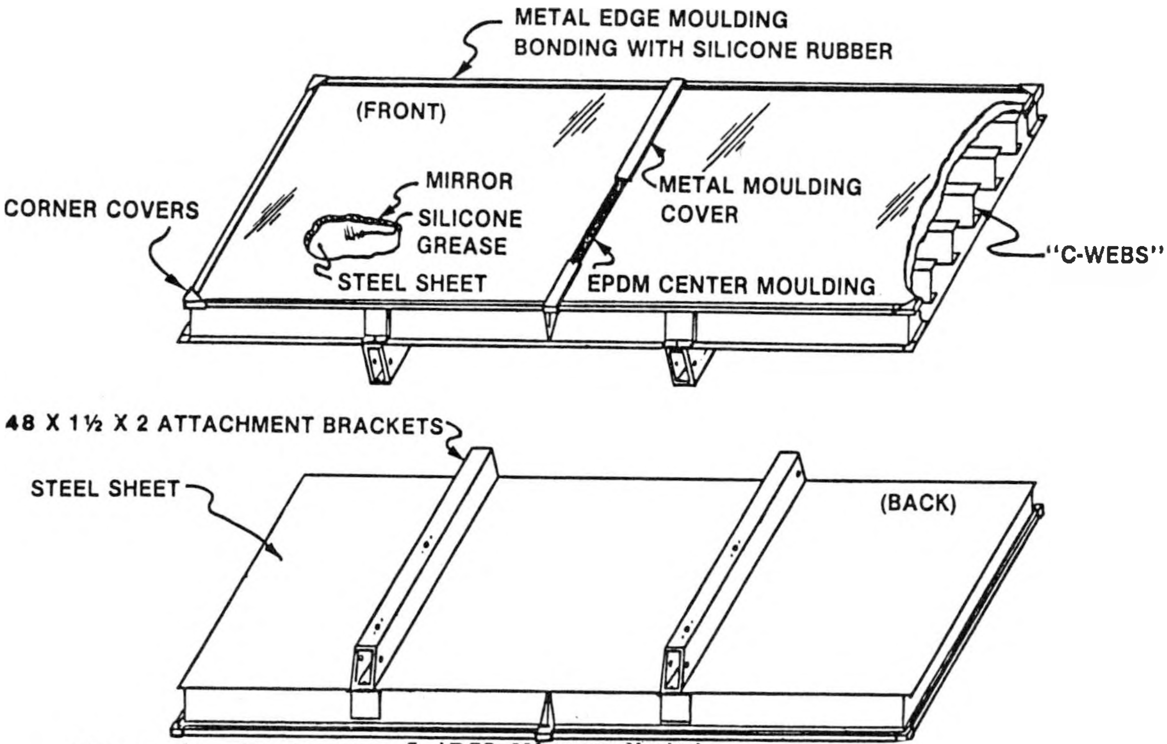


Figure 4: Features of ARCO Mirror Module

Features of ARCO Drive Installation

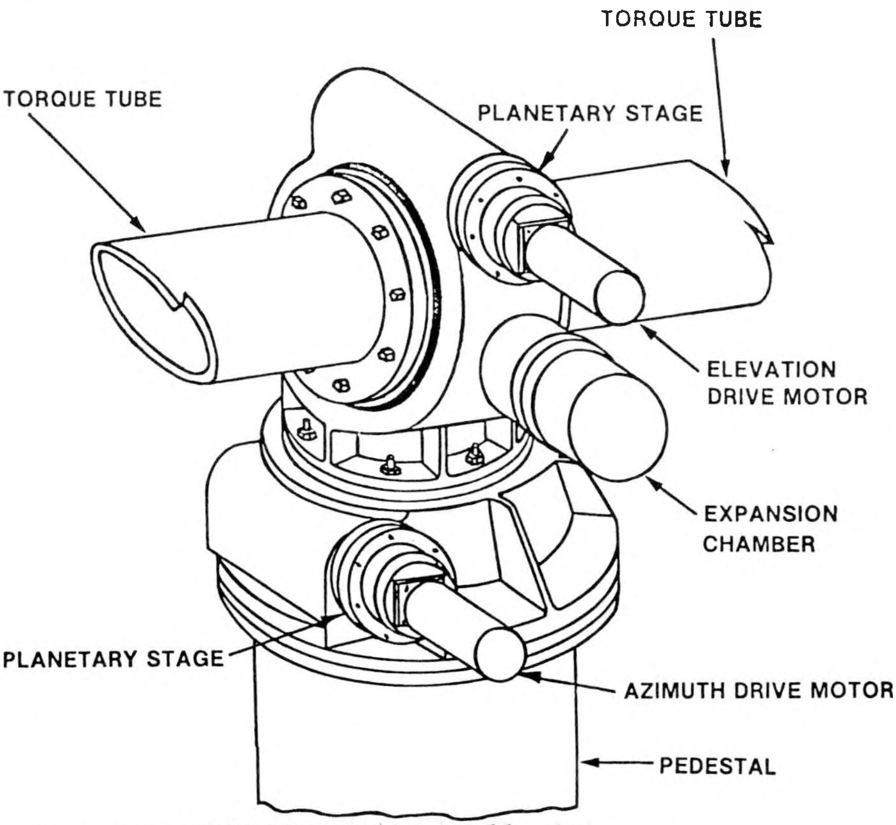


Figure 5: Features of ARCO Drive Installation

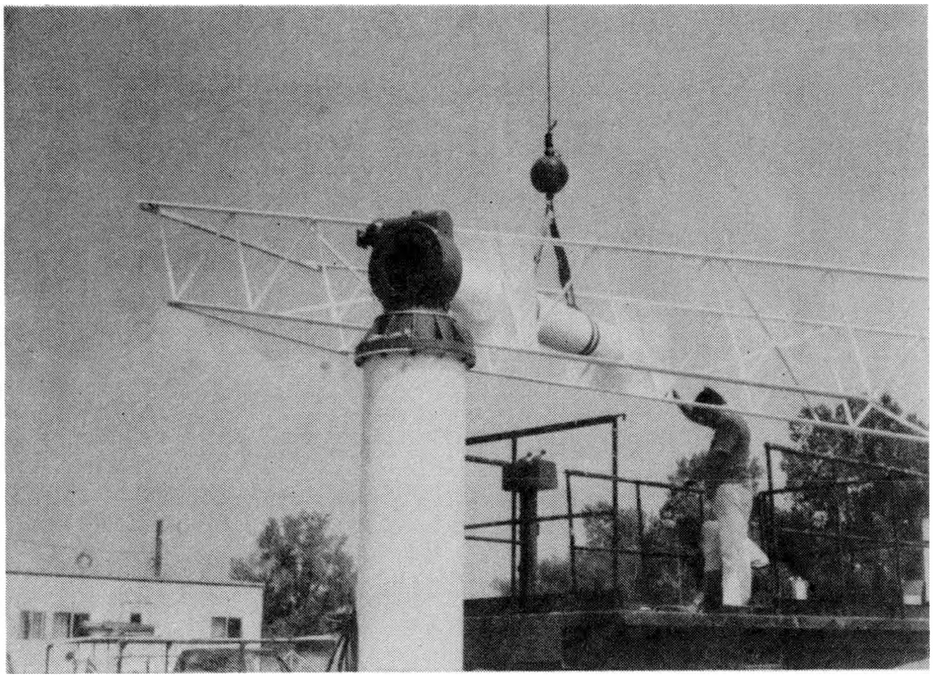


Figure 6: Pedestal, Drive, and Rack Structure During Installation

SECOND GENERATION HELIOSTAT DEVELOPMENT*

Roger B. Gillette
Boeing Engineering and Construction Co.
Seattle, Washington 98124

Boeing Engineering and Construction (BEC), under contract with Sandia National Laboratories, designed, fabricated and delivered two prototype heliostats. These heliostats were installed at the Central Receiver Test Facility (CRTF) in Albuquerque in October, 1980 and were subsequently tested by Sandia. Production/installation plans and cost estimates were also developed for deploying 50,000 heliostats/year in the southwest U.S.

The primary objectives of the contract were to reduce heliostat cost, and involve pertinent commercial industry to the maximum extent possible. To accomplish these objectives, a design was developed which utilizes low cost materials and processes, minimizes production costs, and minimizes field installation labor. Commercial industry participation in the program included Ford Aerospace and Communications Corporation/Ford Motor Company/Winsmith Corporation, (gimbal design and fabrication, production planning), Pittsburgh Corning (reflector panel fabrication), and Centrecon (pedestal fabrication).

Figures 1 and 2 show front and rear views of the prototype heliostat at the CRTF. Major components of the heliostat include; 12 canted reflector panels, H-frame/torque tube support structure, elevation over azimuth gimbal, pre-stressed pile-driven concrete pedestal, and computer controlled digital-electronic control system. Total net reflective area for the array of panels is 42.5m (458 ft^2). The prototype heliostat is designed to be stowed near vertical under normal conditions to minimize both hardware cost and dust accumulation on the reflector surface. Wind velocity higher than 50 mph will require horizontal face-up stowage.

The reflector panel design is a high-reflectance (94%) self-stiffened composite glass panel. Panel size for prototype heliostats is 4 x 10 feet (available glass size). A schematic showing the method of mounting and panel cross section is shown in Figure 3. Reflector panels employ front and back skins of borosilicate glass (Corning 0317 fusion glass). Core material is Foamsil 75; a newly developed borosilicate cellular glass by Pittsburgh Corning, which matches the coefficient-of-expansion of the fusion glass skins. The matched coefficient-of-expansion composite panel minimizes both changes in optical performance with temperature, and stress cycling.

Reflector panels for prototype heliostats were fabricated flat, and canted on the structural frame to provide a focused sun image. Analysis showed that

*Sandia Contract 83-2729C

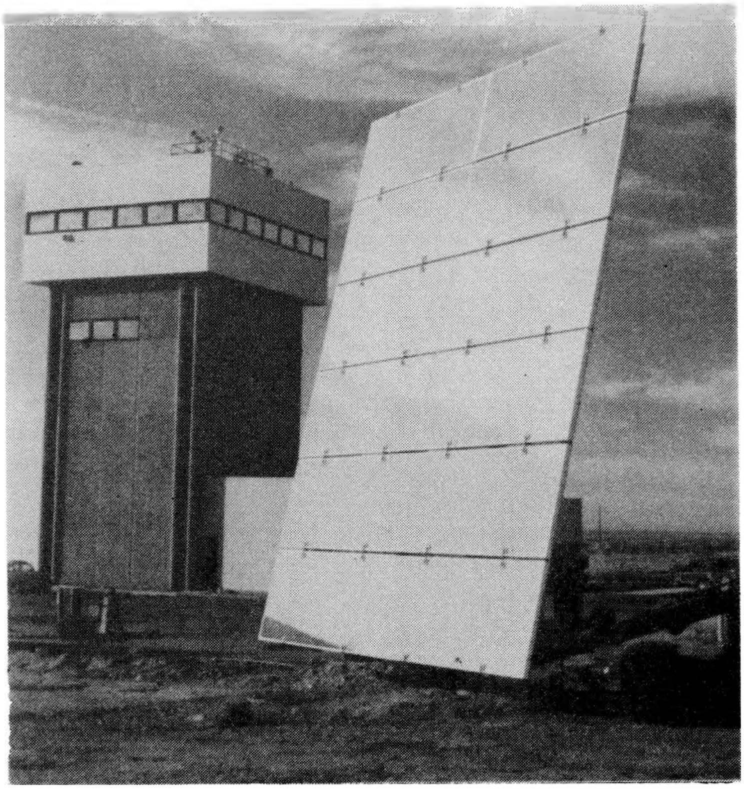


Figure 1. Second Generation Heliostat at Central Receiver Facility (Front View)

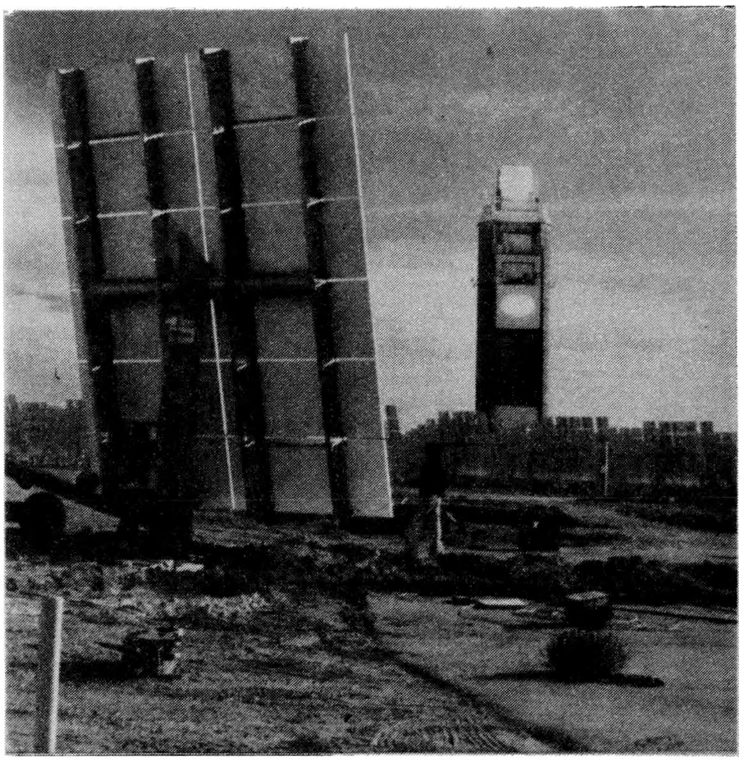


Figure 2. Heliostat Projecting Image onto Target Board

although concave-curved panels would provide a smaller focused image, canted flat panels were adequate to meet the Sandia specifications for an external cylindrical receiver. For more stringent requirements, reflector panels can be built with a curved surface.

The structural frame used on prototype heliostats is shown in Figure 4. A galvanized steel H-frame design was selected based on its production simplicity and minimum part count; both of which result in low cost. The Z-section beams are 24 feet long and 19 inches deep. A 16 inch diameter torque tube ties the beams together and provides an interface to the gimbal. Reflector support brackets transmit wind and gravity loads directly into the beam web. Brackets are designed to accommodate differences in coefficient of expansion between the steel frame and glass panels, to allow canting adjustments, and to support the panel mechanically (no bonded structural joints).

Details of the prototype heliostat gimbal are shown in Figure 5. Azimuth motion is provided with a compact differential planetary gear drive which was selected on the basis of its low compliance and backlash, minimum number of parts, and production simplicity. Gimbal tests have verified the low compliance and backlash characteristic. Elevation motion is provided with a linear actuator which moves the elevation arm on the torque-tube center sectiuon with a traveling polymeric nut on a jack screw. Using a traveling polymeric nut eliminates the need for lubricant on the jack screw and a protective boot; both of which contribute significant maintenance costs over a 30 year lifetime. The elevation drive motor and gear reduction unit are mounted on the top of the azimuth drive unit. Fixed mounting of the elevation drive unit shortens electrical cabling and eliminates cable flexing. Three phase 208V induction motors of 1/3 and 1/6 hp, respectively, power the elevation and azimuth drives. Low cost, solid state sensors are used on the gimbal to provide motion feedback to the digital electronic control system. One set of sensors counts motor revolutions, and a second set provides a reference position check on a daily basis or when commanded.

The pre-stressed concrete pedestal is shown in Figure 6. The pre-stressed pile-driven pedestal was selected on the basis of least cost and proven technology. The 23-5/8 inch O.D. pedestals were driven 15 feet into the soil. Tapped holes in the steel plate at the top of the pile are used for mounting the gimbal.

Positioning of the heliostat reflector panel array is accomplished with a computer-controlled digital electronic system. Major components of the system, shown in Figure 7, include: an ADAC Corporation 1000M computer (with DEC LSI 11/2 processor and memory); a CRT (ADM 3A); a Data Systems Inc. floppy disc memory unit; a DEC LA-120 keyboard printer; and a DELTEC model DLC 1260 line voltage regulator. The equipment is located in the control room at CRTF. Field electronics are located in a weatherprofeed box strapped to the concrete heliostat pedestal. The field electronics package includes a portable switch box for manual heliostat control.

A weight breakdown for the heliostat is shown in Figure 8. The total weight of 3986 lbs (excluding pedestal and electronics) is equivalent to 8.45 lbs/ft^2 of reflective area.

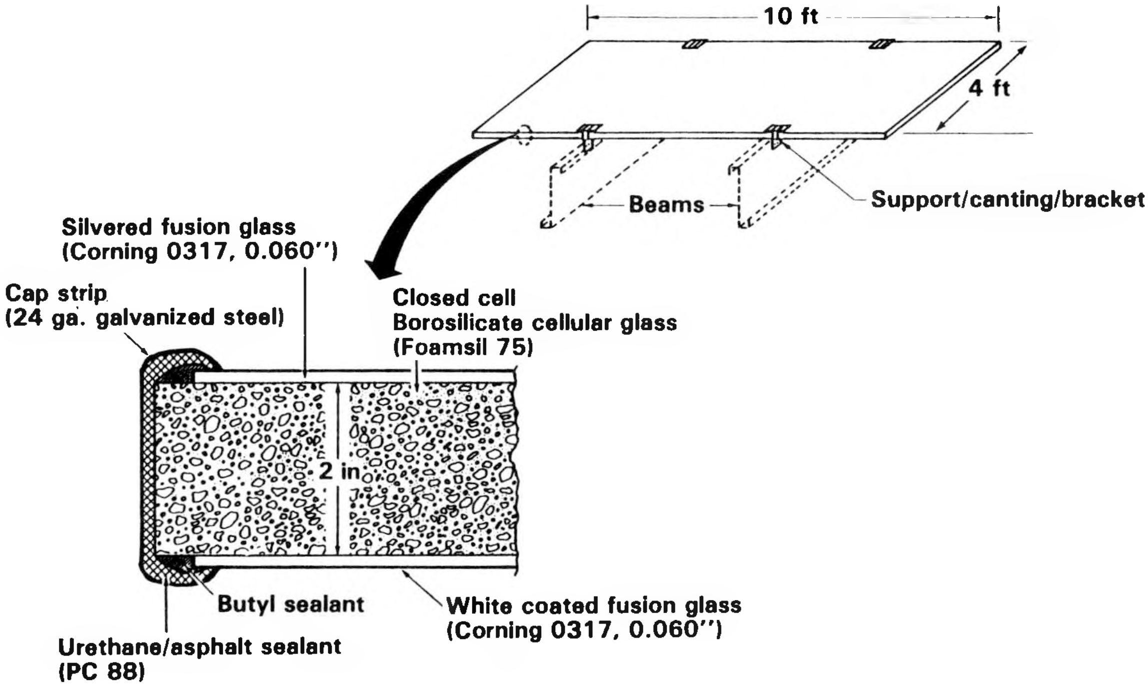


Figure 3. Production Design Reflector Panel

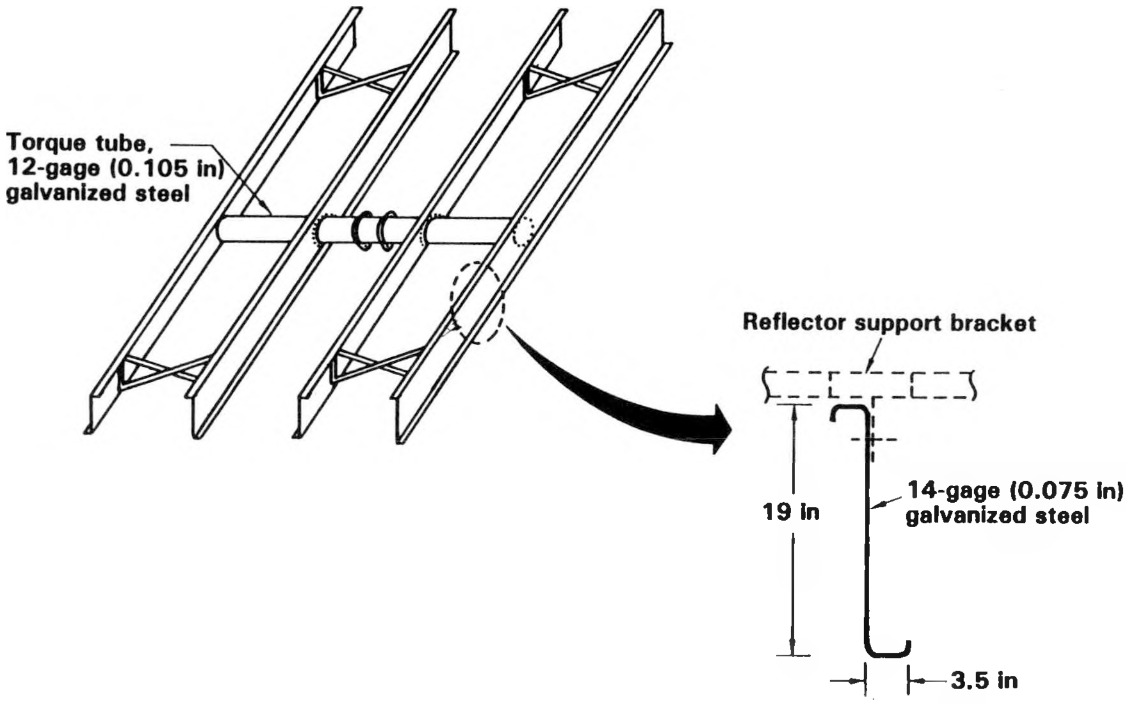


Figure 4. Structural Frame Design

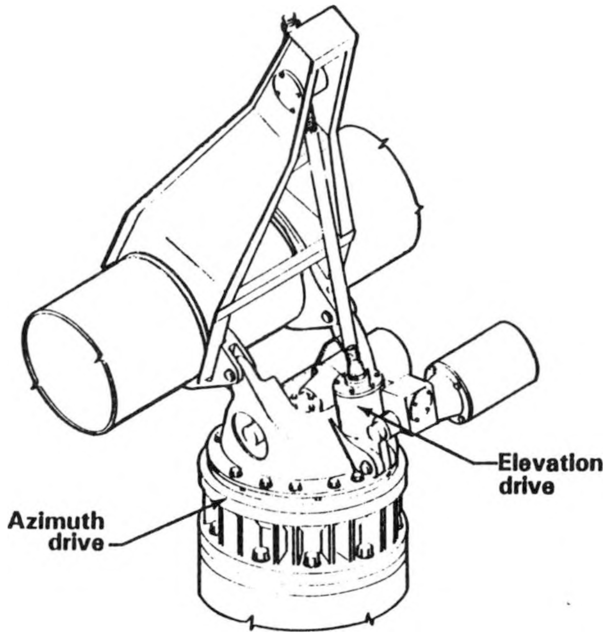


Figure 5. Gimbal Design

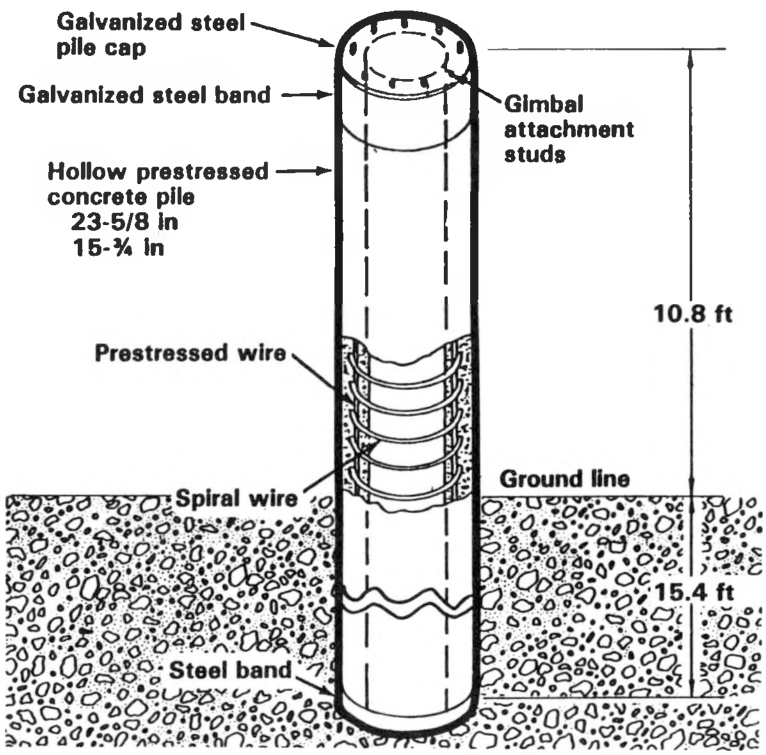


Figure 6. Pedestal Design

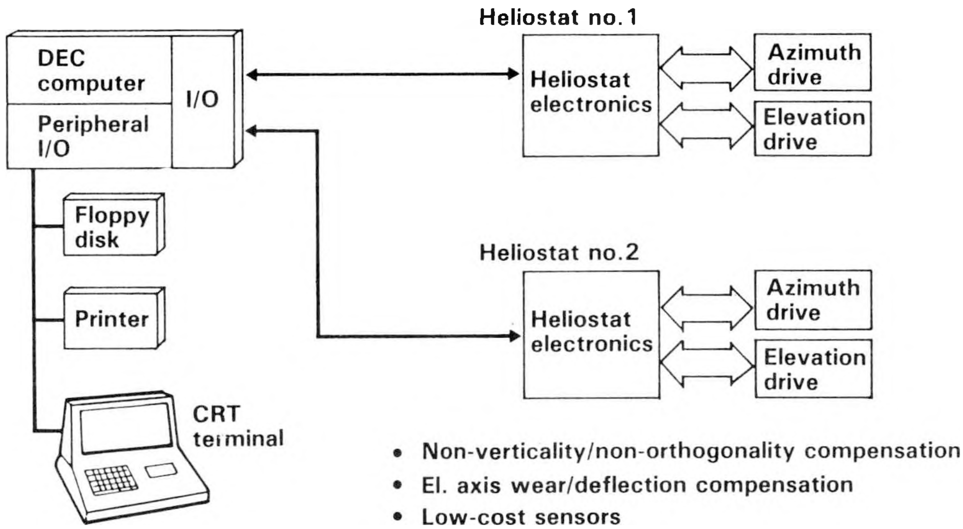


Figure 7. Prototype Heliostat Control System

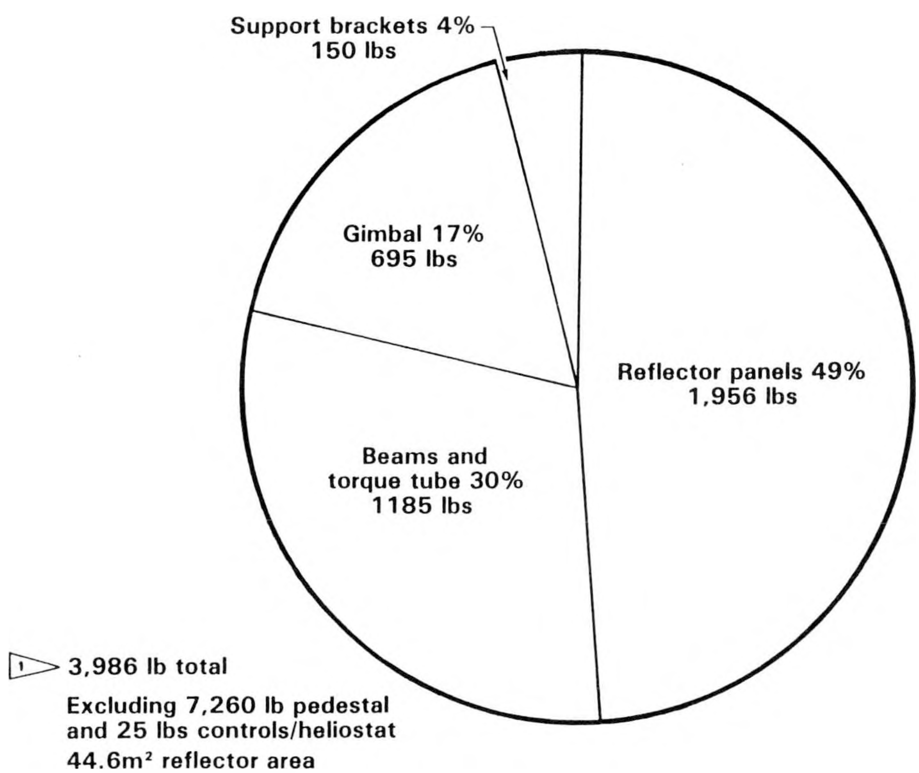


Figure 8. Prototype Heliostat Weight Breakdown 1

MARTIN MARIETTA

SECOND GENERATION HELIOSTAT "1981"

Lloyd P. Oldham

Martin Marietta Denver Aerospace

Denver, Colorado

Introduction

The Martin Marietta second generation heliostat "1981" is the sixth Martin Marietta heliostat design in a continuing program to provide high performance, low cost collector subsystems for solar thermal central receiver applications. This heliostat, although specifically designed for a mass production scenario of 50,000 heliostats per year, will provide high performance at low cost for both limited and mass production rates. The design is based on a combination of new concepts, high-volume production approaches, and Martin Marietta's experience gained through almost a decade of design experience and the successful fabrication and installation of all three major collector subsystems funded to date by the United States Department of Energy. The design was developed as a part of a "Second Generation Heliostat Development" contract funded by Sandia National Laboratories, Livermore, California.

During the course of this contract Martin Marietta has completed three basic tasks. The first of these tasks was to develop a low cost, mass-producible heliostat design with performance characteristics to achieve minimum busbar energy cost from a 50 MWe central receiver power plant. The design goals were: a heliostat life of 30 years with no scheduled maintenance of structural components; high-reliability low-maintenance electronic controls; and inverted (mirror face down) stow to provide protection against storm or hail damage and the lowest possible mirror washing costs. Particular attention was given to achieving a design with no scheduled maintenance, easy maintenance, minimal sensitivity to electrical noise and lightning, and low field operating and maintenance costs. Low operating costs have been achieved by first maintaining the single operator control capability developed for the Martin Marietta first generation (Barstow) heliostats, and then improving the control system reliability and reducing the power required to operate the field by lowering the parts count in the control system.

The second of the three tasks was to develop a preliminary design and a cost projection for a heliostat central manufacturing facility sized to produce 50,000 heliostats per year and to provide preliminary scenarios, techniques, tool designs, concepts, and costs for the manufacture, transportation, installation, and maintenance of the second generation heliostats at that production rate. The estimated costs were based on installing the heliostats in 50MWe power plants (5,147 heliostats per plant) located within a 400-mile radius of the central manufacturing facility. The task also identified Albuquerque, N.M. as a very cost effective manufacturing facility location in the eight-state region of the southwestern United States. The results of this analysis projected the first year installed cost of the second generation heliostat at \$103.39/m^2 in 1980 dollars.

The third task consisted of fabricating and installing two prototype second generation heliostats at the Central Receiver Test Facility in Albuquerque, New Mexico, and supporting Sandia National Laboratories in the testing of these prototypes. Extra mirror assemblies were also provided for independent testing.

The results of the performance tests have shown that the Martin Marietta second generation heliostat is essentially ready to meet the needs of the user community, the design is sound and the unit will in fact have a low life-cycle cost. As a result of the experience gained during the initial prototype fabrication and performance tests performed both by Martin Marietta Denver Aerospace and Sandia National Labs, heliostat design refinement was initiated and cost estimates were updated.

Design refinement to date has consisted of improving the design of the mirror assembly and fabricating new prototype mirror assemblies which are now being tested by Sandia National Laboratories. Figure 1 shows the one of the second generation heliostats being tested.

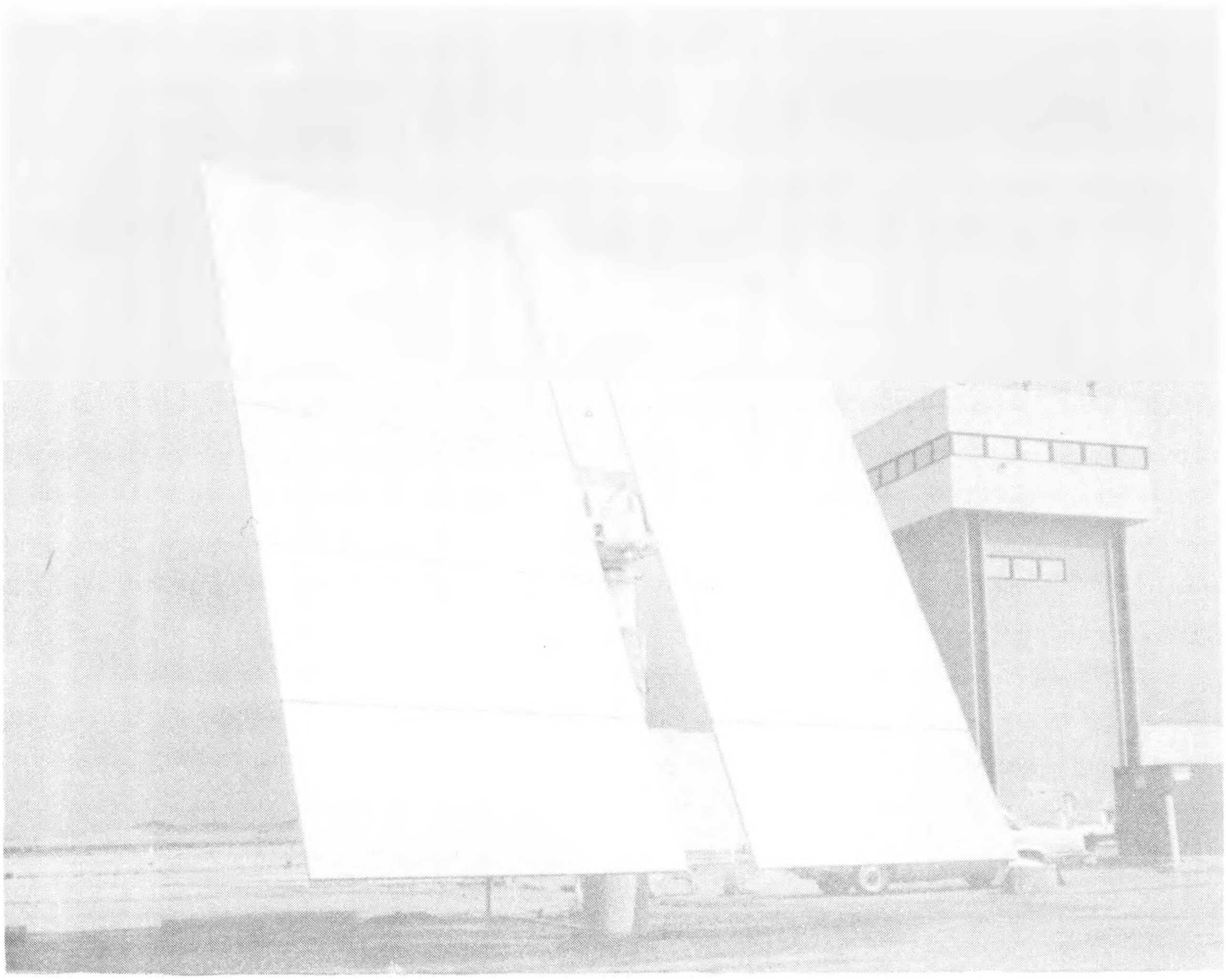


Figure 1 Second Generation Heliostat - Front View

Based on the results of this program and other on-going development activities, Martin Marietta has defined additional cost reduction improvements in both this second generation and in our first generation heliostats. Such improvements will be incorporated as they are demonstrated and tested. This approach will provide cost effective heliostats both now and in the future.

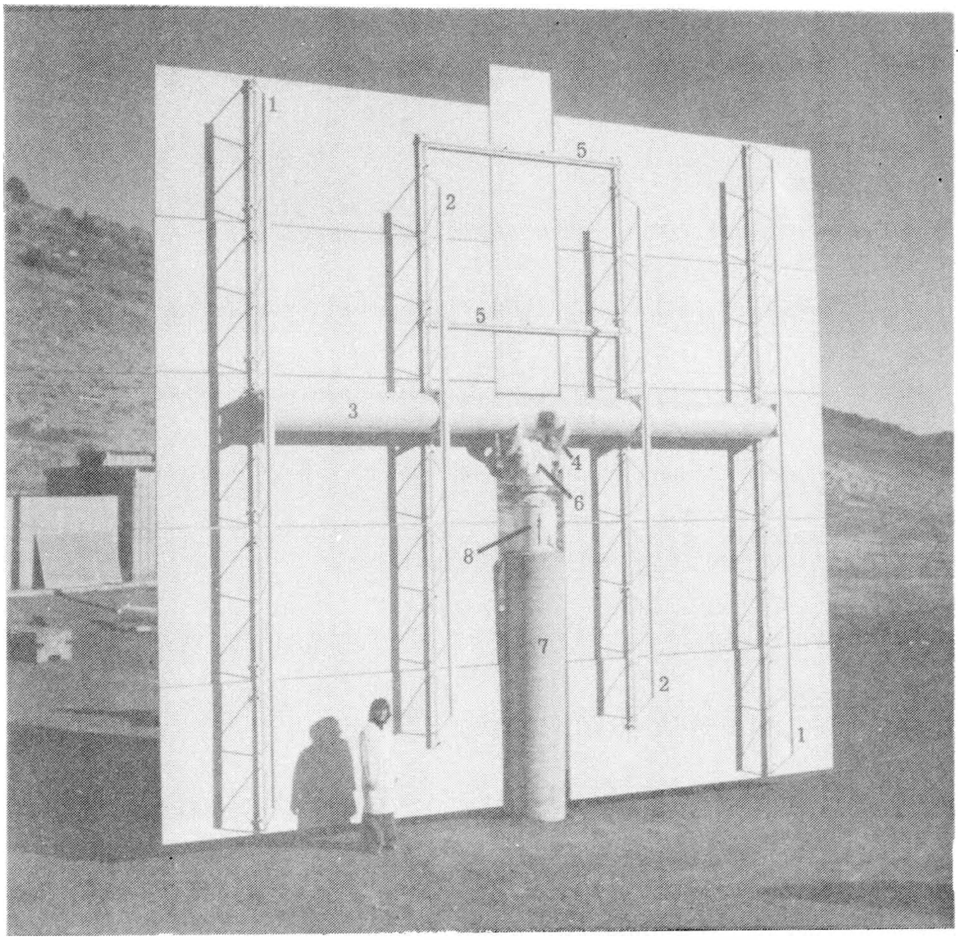
Heliostat Design Description

The second generation heliostat design has evolved through eight years of heliostat hardware fabrication, field installation, and test experience. The design-to-life-cycle cost and design-for-production approach has resulted in a low-cost, no-scheduled-maintenance heliostat that uses competitively priced commercial components in concert with readily mass-producible heliostat-unique items. The heliostat provides 57.4 m^2 (618 ft^2) of active thin second-surface glass mirror area. It incorporates 11 individually canted mirror assemblies mounted on a rigid, lightweight rack assembly structure. The overall size of this reflective assembly is 8.13 m (26.67 ft) wide by 7.66 m (25.14 ft) high. A summary of basic heliostat parameters is given in Table 1. The heliostat is designed to meet the design and performance requirements defined by Sandia National Laboratories in "Collector Subsystem Requirements, Drawing No. A10772, Issue C".

TABLE I Second Generation Heliostat Summary

Heliostat Reflective Area	57.4 m^2 (618 ft^2)
Projected Reflectivity - 0.060" Fusion Glass (0.060" Low Iron Float 93%)	96%
Heliostat Weight (Does not include foundation/pedestal)	2,308 kg (5,085 lbs) 40.2 kg/m^2 (8.23 lbs/ft^2)
Projected Heliostat Installed Cost (50,000/yr in 50 MWe fields)	\$5,936 (103.39/m^2)
Heliostats Required for Sample 50 MWe Field	5,147
Estimated Annual Operations and Maintenance Cost	\$47.88/heliostat (\$0.833/m^2)
Manufacturing Plant Location	Albuquerque, N.M.
Daily Power Consumption (10.0 hour day)	123 Watt-hours/heliostat
Mean Time Between Failures (For a 5147 Heliostat Field)	6.7 hours of operation

The structural support members of the heliostat are shown in Figure 2. The open web bar joists and the tubular steel elevation beam form the basis of the rack assembly that supports the mirror assemblies. This rack assembly, combined with the 11 mirror assemblies, forms the heliostat reflective assembly.



Heliostat Assembly

Reflective Assembly
- Mirrors (11 Total)
- Rack Assembly
  - 1-Long Bar Joist
  - 2-Short Bar Joist
  - 3-Elevation Beam
  - 4-Control Arms
  - 5-Mirror Support Stringer

Drive Mechanism
- 6-Drive Mechanism

Pedestal/Foundation
- 7-Ped/Foundation
- 8-Pedestal I/F Tube

Figure 2 Second Generation Heliostat - Back View

The heliostat reflective assembly may be pointed in any desired direction using a single two-axis (aximuth and elevation) gear drive with individual two-speed dc motors for each axis. This drive mechanism assembly (Fig. 3) incorporates an external locking mechanism that mechanically locks the heliostat in the inverted stow position during high wind conditions. The drive mechanism mounts on the top of a one-piece concrete pedestal/foundation with an embedded tubular steel interface between the concrete and drive mechanism. This interface tube provides a protective enclosure for the heliostat control electronics.

The heliostat mirror assemblies were designed to use 1.5 mm (0.060 in.) thick second-surface mirrors. Either fusion glass or low-iron fload glass can be used depending on glass availability and cost. However, fusion glass was selected as the baseline for estimating heliostat cost because of the high projected reflectivity (up to 96%). The prototype test mirrors were fabricated using both 1.5 mm and 2.0 mm regular float glass due to the unavailability of fusion and low iron float glass in very small quantities.

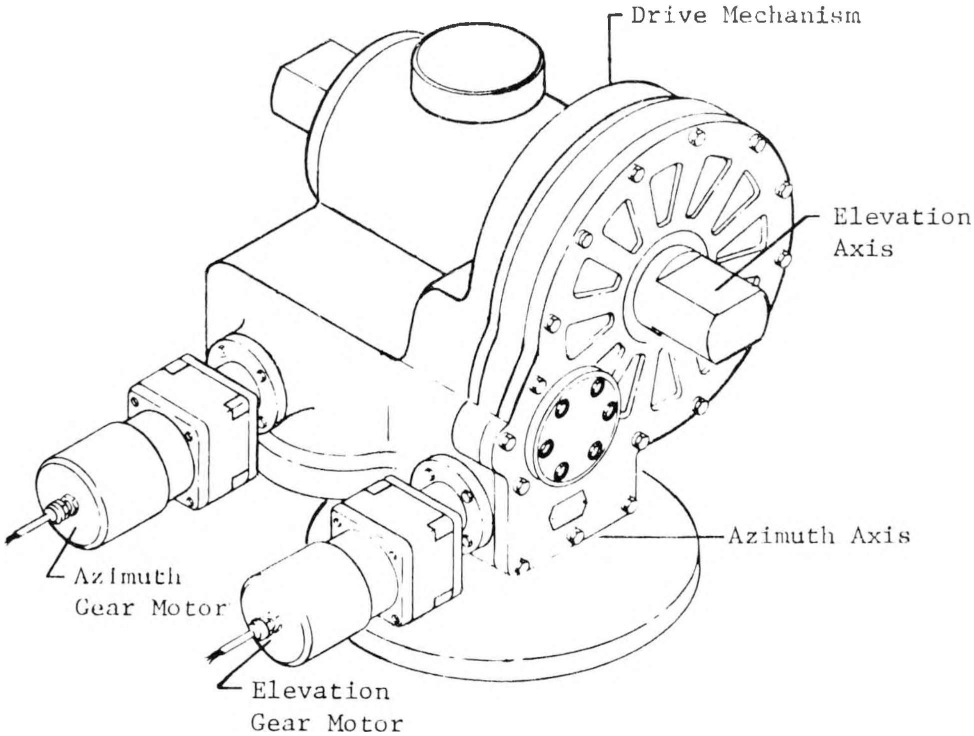


Figure 3 Drive Mechanism Assembly

Each mirror assembly (Fig. 4) uses two mirror lites, each approximately 1.8 x 1.5 m (6 x 5 ft) for the full size mirror assemblies, with half-width mirrors for the half-size mirror assembly. The mirrors are supported on a steel/honeycomb/steel sandwich structure that is approximately 1.5 x 3.7 m (5 x 12 ft). To achieve the most cost effective design, the original structure incorporated the use of phenolic-impregnated paper honeycomb. This provided a design with maximum rigidity and minimum cost and weight. During design refinement, the paper honeycomb core was replaced with aluminum honeycomb core to obtain test experience with this environmentally insensitive material and thus provide an optional design that removes any concern that paper core might not meet the 30 year life requirement. Other improvements in the refined mirror assembly include a new higher strength core bonding adhesive and an improved edge frame design. The mirrors are mounted to the support structure using a low-modulus adhesive/sealer that seals the mirror backing to prevent mirror corrosion. An edge frame and dual-edge seal are provided to prevent degradation from moisture penetrating the edges. The mirror assemblies are mounted on the rack assembly using a set of three support doublers. This three-point mount provides a readily adjustable system for optical alignment.

Development of the second generation heliostat control system was limited due to Sandia funding constraints. Therefore, an improved Martin Marietta first generation (Barstow Pilot Plant) heliostat control system was used. The improvements consisted of the incorporation of fiber optics communications, a computerized heliostat leveling capability, and modifications to the encoders to reduce parts count, increase the reliability and lower the cost. These improvements resulted in a smaller, more reliable control system that is insensitive to electromagnetic interference and lightning and uses 30% less power to operate the heliostat than the first generation design. The result is a proven control system with both lower fabrication and maintenance costs.

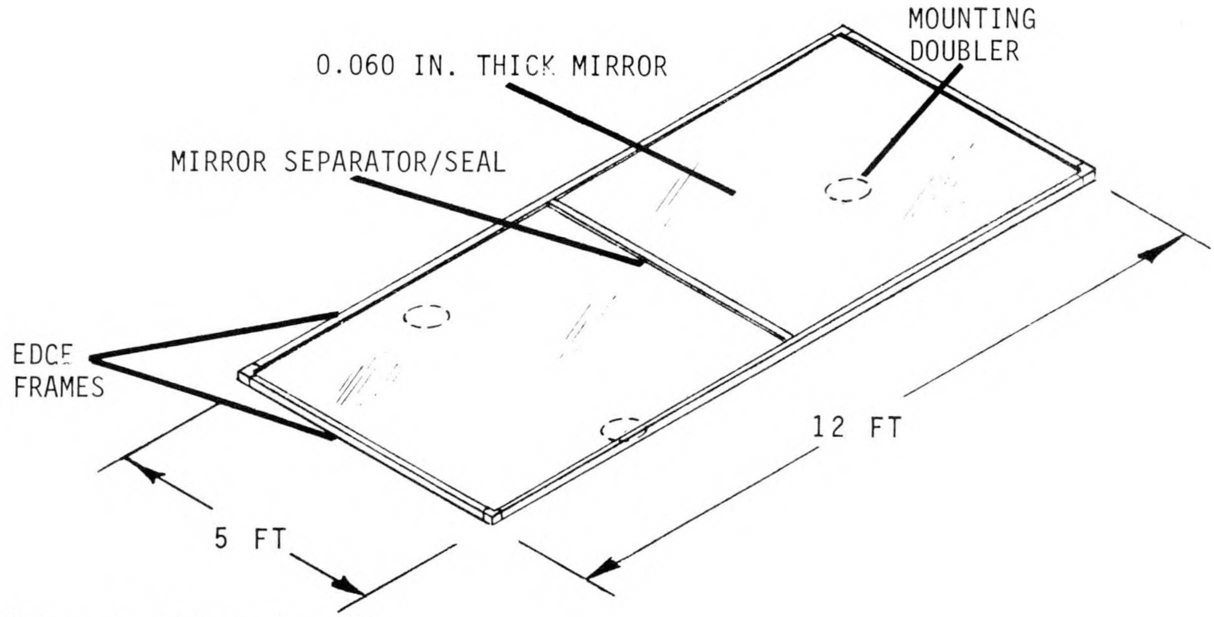


Figure 4 Mirror Assembly

To achieve the lowest possible life-cycle costs, the heliostat design has been closely coordinated with manufacturing engineering personnel to assure producibility using mass-production techniques. Personnel experienced in field maintenance have also been employed to assure ease of maintenance with minimum cost. Many new design features to minimize life-cycle cost have been incorporated. The most significant design features are:

1) Very high reflectivity thin fusion glass mirrors for maximum reflectivity with the capability of substituting thin low-iron float glass if more cost effective in the near term;

2) Totally sealed mirror backs (mirror to steel laminate) to eliminate mirror corrosion;

3) Lightweight, low-cost mirror assembly of steel/aluminum honeycomb/steel sandwich construction that provides no thermal defocus of the mirror, maximum hail protection, and a rigid, high-quality optical surface contoured for optimum performance;

4) Inverted (face down) stow that provides the capability of placing the mirrors face down during storms and at night to minimize wind and hail damage and mirror-washing frequency. The decision to stow inverted also decreases the possibility of damage from an unexpected storm during the night;

5) A maintenance-free, combined azimuth/elevation gear drive mechanism with a mechanical locking device for high wind conditions;

6) Computerized heliostat leveling and pointing;

7) Steel tubular pedestal-to-drive interface section embedded in the top of the concrete pedestal foundation to form a protective housing for the heliostat electronics;

8) Reinforced concrete combined pedestal/foundation poured in place at the field site with a below-ground design that will be optimized for each site. The design can be used at any site regardless of soil conditions;

9) Proven open-loop computer control system and microcomputer electronics with very low power consumption;

10) Fiber optic communications consisting of fiber optic cables, transmitters, and receivers throughout the collector field;

11) Advanced incremental encoders that have a low parts count and high reliability.

These features combine to provide a lightweight heliostat design that addresses the need for low initial and maintenance cost, increased efficiency with good beam quality, and mass producibility.

Heliostat Cost Projection

One of the most important results of the second generation heliostat development program was the heliostat cost analysis. This analysis was based on providing projected first year installed heliostat costs in April 1980 dollars for a production rate of 50,000 heliostats per year. The analysis assumed the heliostats would be installed in 50 MWe power plant collector fields located within 400 miles of a central heliostat manufacturing plant. The analysis considered all costs, from the design and set-up of the central manufacturing plant through the final checkout of the installed heliostat fields. The current projected price of the installed heliostats is \$5,936 per heliostat or \$103.39/m^2 in April 1980 dollars. This price was calculated based on a return on investment of 17.5%. The annual operating and maintenance cost for the second generation heliostat was estimated to be \$47.88 per heliostat or \$0.833/m^2.

Results/Future Plans

The second Generation Heliostat Development Program has provided valuable insight into the design and production of heliostats for current and future applications. In addition to demonstrating that both the current first and second generation Martin Marietta heliostats are technically acceptable with very little design refinement, the program has also provided insight into areas where additional cost reduction and improved reliability can be achieved without compromising the performance of the central receiver plant. It is Martin Marietta Corporation's intent to continue to use our capabilities and experience to make Solar Thermal Central Receivers a viable source of alternative energy through:

1) Continuing to make first generation heliostats available for the near term market;

2) Incorporating timely design refinements into the first generation heliostat, to reduce cost, as they are demonstrated to be technically acceptable;

3) Providing our second generation heliostat to the market in a timely manner;

4) Continuing our aggressive heliostat development program to reduce the life-cycle-cost of the first and second generation heliostats and to provide improved heliostats and support systems as required by the market place.

Conclusions

The results of this development program have provided several conclusions regarding the heliostat collector subsystems for solar central receiver application, i.e.:

1) Heliostat technology is sufficiently mature to provide reliable heliostat collector fields that meet or exceed the performance parameters required.
2) Reasonably low heliostat costs can be achieved at moderate heliostat production rates.
3) Continuing refinement of the heliostat design and understanding of the collector field requirements will provide even lower costs in the future.
4) Heliostats are now and will continue to be available to meet the requirements of the solar thermal central receiver user community.

SECOND GENERATION HELIOSTAT

D. A. Steinmeyer
McDonnell Douglas Astronautics Company
Huntington Beach, CA

Under contract to Sandia National Laboratories, Livermore, California, McDonnell Douglas Corporation (MDC) has developed a Second Generation heliostat. The development program included fabrication and test of two prototypes, conceptual design of production capability, and life cycle cost projections.

The primary thrust of the MDC Second Generation Heliostat program was the development of a design producible with currently available equipment and processes while producing a generation advance over the Barstow program in the performance and cost of heliostat fields.

The test program was structured to demonstrate readiness for production at any volume. The Sandia test program was supplemented at MDC and suppliers to completely verify the product for production readiness.

The production costing was performed at the 50,000/year level per the ground rules; and, to minimize the skepticism that always accompanies future production cost projections, this activity was independently performed through the General Motors Technical Center, Energy Systems Group.

The program resulted in a heliostat of unique configuration meeting all the Second Generation specification requirements. The test program demonstrated the environmental integrity of the reflector assembly and the 30-year operational capability of the controls and drive components. Exceptional pointing and tracking accuracy has been demonstrated, well within the specification and stable over the eight months of testing at CRTF. The production facilities design was accomplished using currently available manufacturing equipment. Suppliers for materials and parts are predominantly currently capable of high volume.

The MDC Second Generation heliostat has a reflective area of about 57 square meters which is over 40 percent larger than the Barstow units. It is short and wide which provides a lower center of pressure and lower loads which reduces support structure, drive, pedestal, and foundation material requirements. The vertical orientation of the panels which also reduces material provides a full glass frontal area. This configuration also facilitates rapid field cleaning procedures with a minimum number of breaks in the vertical surface for gravity fluid flow and an unobstructed path across the face of the heliostat. Cleaning is the only scheduled maintenance task. The gap between the reflector assemblies allows clearance for field assembly.

Nonoperational stow is -2 degrees from vertical, with face-up positioning when intensive winds are anticipated.

The support structure is galvanized steel, roll formed and spot welded. The roll form supplier, Van Huffel Tube, is currently capable of supporting volumes up to the 50,000/year production level. Roll-formed parts are also used in the main beam and the mirror stiffeners. The structure is a deflection critical design, with significant margin.

The mirror module is a conventional mirror-glass laminate with a silicone edge seal for additional weather protection, capped with galvanized steel for handling protection. This laminate is conventional in that it uses glass-to-glass laminated with an adhesive process known to have long life. The integrity of the silvered surface is not impacted by the subsequent structural containment of the mirror system, and the two surfaces are thermally compatible. Mirror surface quality is controlled by the flatness of the float glass backlight.

Vertical and horizontal curvature is held in the panel by the hat section stringers bonded to the back of the panel and the cross braces. Two different proven adhesives used on previous MDC heliostats were used to attach the hat section through an intermediate shim. These materials are on heliostats which were placed in the field over five years ago. This approach was followed for the high volume design with an off-line bond and stack of a slow curing glass-to-steel assembly, followed by bonding of the hat sections to the curved glass with a rapid cure adhesive. This minimized the amount of curvature tooling required.

The mirror modules are mounted and canted to the support structure in the factory to produce a reflector assembly. This assembly is then transported to the field for installation. This procedure was accomplished on the prototypes with reasonable success. Initial image quality was good. With implementation of the three cross braces to the mirror modules previously described, we are confident this approach is sound. The assemblies were shipped horizontal on the prototypes. Vertical orientation using air-ride low-boy trailers will be used in production.

The drives used are consistent with previous MDC heliostat developments. However, parts and material are significantly reduced for the Second Generation program. Elevation is a two-stage jack made by Duff-Norton, using a Saginaw Gear ball screw and an Illinois Tool Works helicon gear. Two-stage azimuth drive is provided with a United States Machinery 10-inch diameter harmonic drive, used in MDC heliostats since 1976. Input is provided through another helicon gear. AC motors are used, provided by Emerson Electric, with the input pinion integral to the motor shaft. AC was specifically chosen to avoid brush problems for 30-year life.

Both drives are sealed and lubricated for the maintenance-free 30-year life. The peak dynamic loads occur in azimuth while slewing in a wind.

The harmonic drive dynamic capability has been increased since 1976 from 85,000 in-lbs to over 145,000 in-lbs by design refinement. These refinements have had little effect on the production labor or material requirements. Static capability has also increased. However, it is substantially above requirements, and consequently the upper limit has never been tested.

The drives are assembled to the main beam and subsequently to the pedestal in the factory. This assembly is completely wired and checked out in the factory including adjustment of all reference sensors and shipped to the field in this configuration for heliostat assembly.

The foundation is a conventionally drilled and poured column with a tapered metal cap extending 4 feet above grade. The taper is about 1/4 inch in 4 feet. Vertical alignment of the cone to ± 1 degree is accomplished with a carpenter's level, shimmed on one end to the taper. The wiring conduit and a drain pipe are implaced before the pour, and the top of the pour is sloped to the drain inlet to preclude the potential of water standing in the pedestal.

Heliostat grounding of the pedestal is achieved by the concrete encased rebar pier approach in compliance with the national electric code. All electric assemblies and cable interface sheaths are grounded to the pedestal structure using fittings and termination hardware designed for the purpose. The grounding system approach satisfies all personnel safety criteria. Lightning protection is achieved by the shield, termination techniques, and ground system. Power line protection is further provided by electrical surge arresters. Data line protection is further provided by terminal protection at line drivers and receivers.

The field installation interfaces consist of the alignment pins and bolting holes for the reflector assembly mating to the main beam, and the pedestal engagement of the foundation cone. The pedestal inplacement takes place very rapidly, with little guidance required. The overlap when fully loaded into place is about 36 inches. This installation has been performed four times in less than ten minutes each time. Pedestal alignment of less than 5 mrad has been achieved in all cases, even though controls alignment allows a significantly greater error.

The reflector assembly is raised and placed in position through the main beam guide pins, and bolted into place. This operation also takes less than ten minutes per reflector on the prototypes.

The final installation activities involve the heliostat controller which may be installed on the pedestal either in the factory or the field. The controller is mounted on the pedestal, accessible from the ground. Weather proof connectors interfacing the field wiring and the drive system are provided on the back of the standard nema-vented box. They are accessible by releasing a pin and swinging the box away from the pedestal. For maintenance the whole control box is replaced and the unit under repair is taken to maintenance.

The controller is the heliostat end of a three-tier control system provided for the heliostat array. The complete system was provided to CRTF with the prototype heliostats. The functions of each component are based on providing low data rates with high total field availability. Consequently, the positioning computations and control emanate from the field controller, which in our design is collocated with the power distribution hardware in support of approximately 30 heliostats.

Position sensors on the gimbal axes, the helicon gears, and the motors are used in conjunction with the HFC and HAC memory to provide a rapid position reference update in the event power interruptions occur in the field.

Control system testing has been ongoing since 1978 on the component and subsystem level, as well as in operation and life cycling on heliostats in the field. These tests have accumulated operational simulations of over 40 years on components and subsystem operational times exceeding 8,000 hours on one unit of five under test, with a minimum of 2,300 hours. No component failures have occurred during this testing. Thermal tests representing an overtest condition to the specification have included -30°F soak and operate, and +158°F operate.

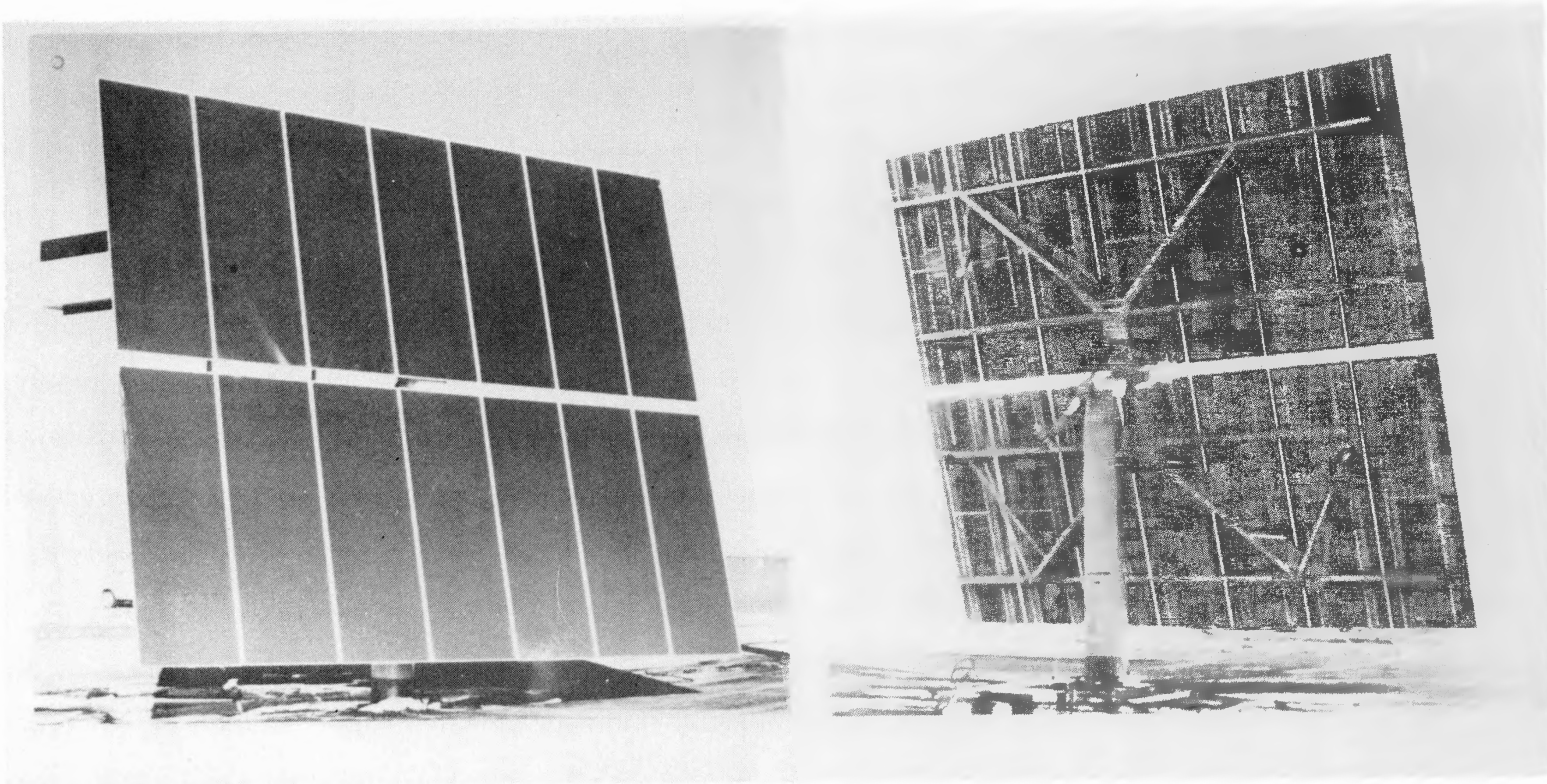
Tracking accuracy of 0.5 mrad RMS have been maintained over the eight months of operation at CRTF, and after 90 mph wind load tests.

To totally demonstrate the drive system performance, life tests were conducted on both the azimuth and elevation drives. These tests were conducted last spring, following heliostat testing at CRTF, and the azimuth drive included the latest updates in the design, providing the previously mentioned dynamic torque capability. Azimuth drive inspection after tear down following load testing to 30-year life showed minimum wear. No functional anomolies occurred during the test. After teardown inspection of the elevation drive at CRTF, 30-year ball screw life was questionable. Tests were undertaken at Saginaw Gear, which resulted in an increase in ball screw diameter from 1-1/4 inch to 1-1/2 inch, to demonstrate 30-year life. The 1-1/2 inch diameter screw is a standard current production part, while the 1-1/4 inch screw is a special part originally chosen for the reduced material used in high volume.

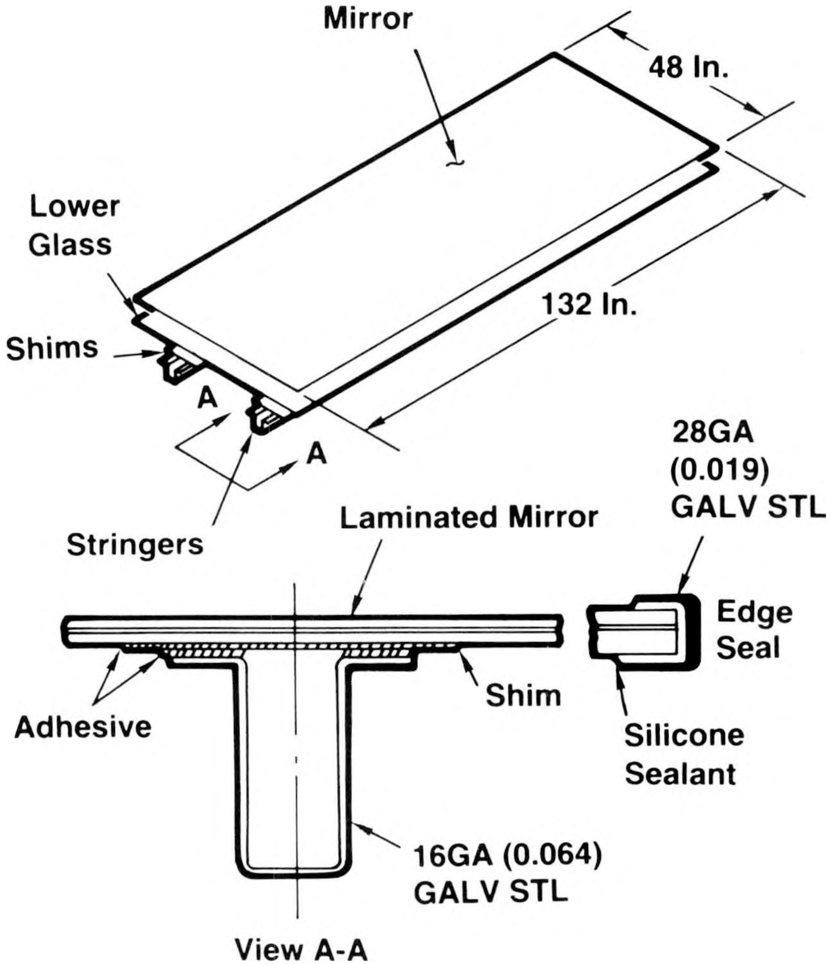
The production cost analysis performed by General Motors Energy Systems was supported by the F. Jos. Lamb Company, a supplier of high volume manufacturing equipment, and Harrison Radiator Division of General Motors, a high volume producer. The detailed analysis performed provided defintiion of further cost avoidance as well as the volume production scenario and costs. This analysis as well as the results of the rest of the program are provided in the program reports.

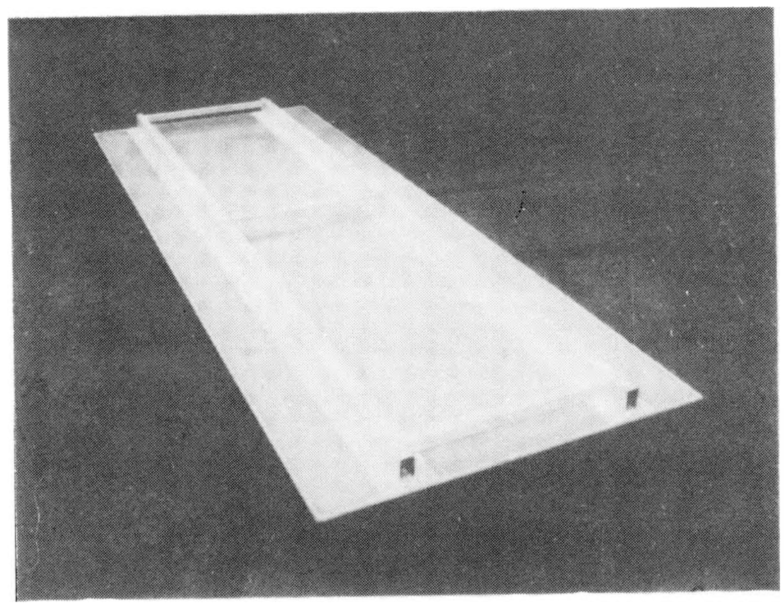
The complete success of the test and verification program provides the baseline from which continued refinement and cost avoidance can proceed. Nonetheless, as a result of selecting components and suppliers currently in volume production, the MDC heliostat can be provided now at reasonable prices in moderate volumes.

MDC HELIOSTAT



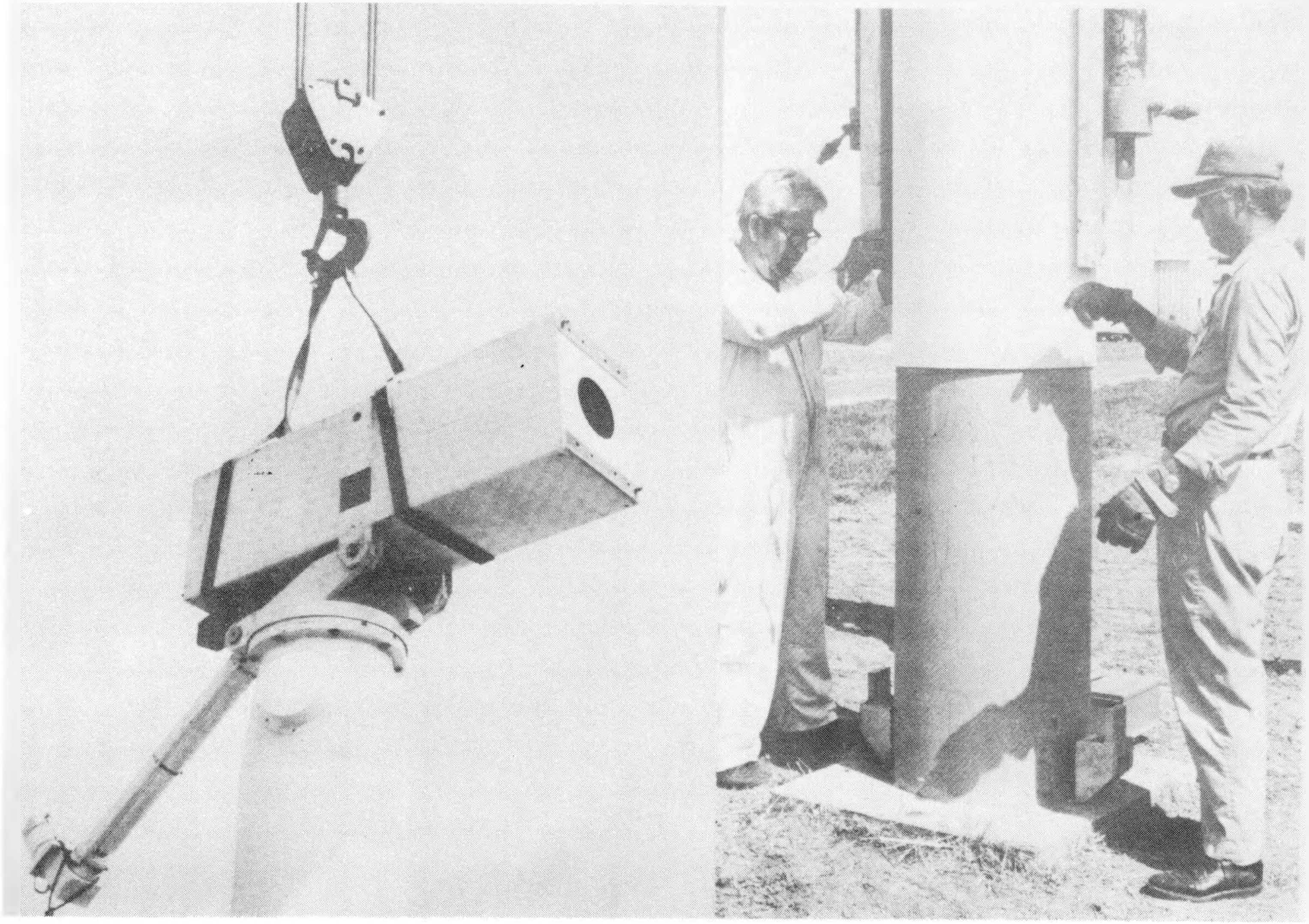
LAMINATE MIRROR MODULE





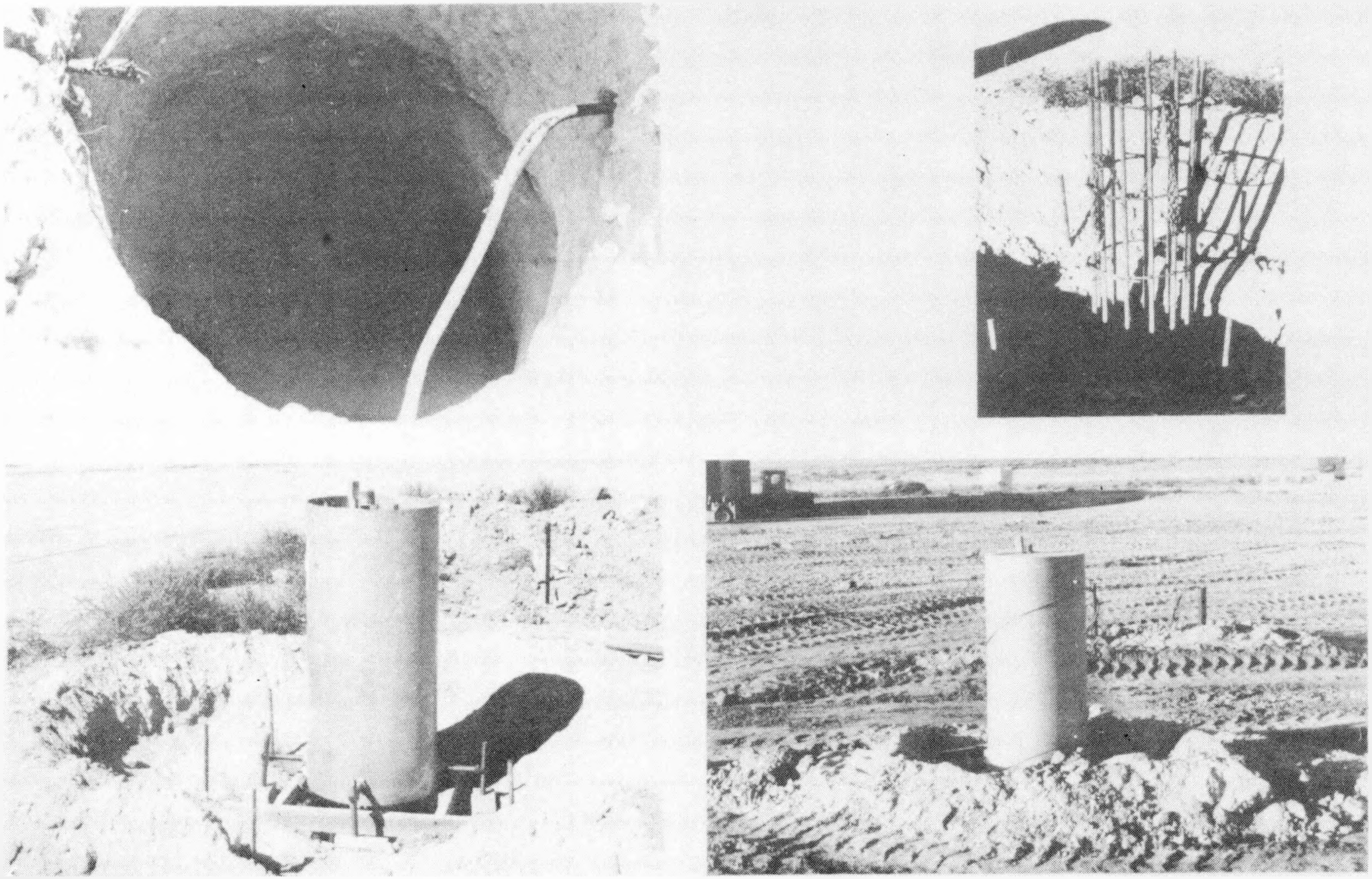
VFN212

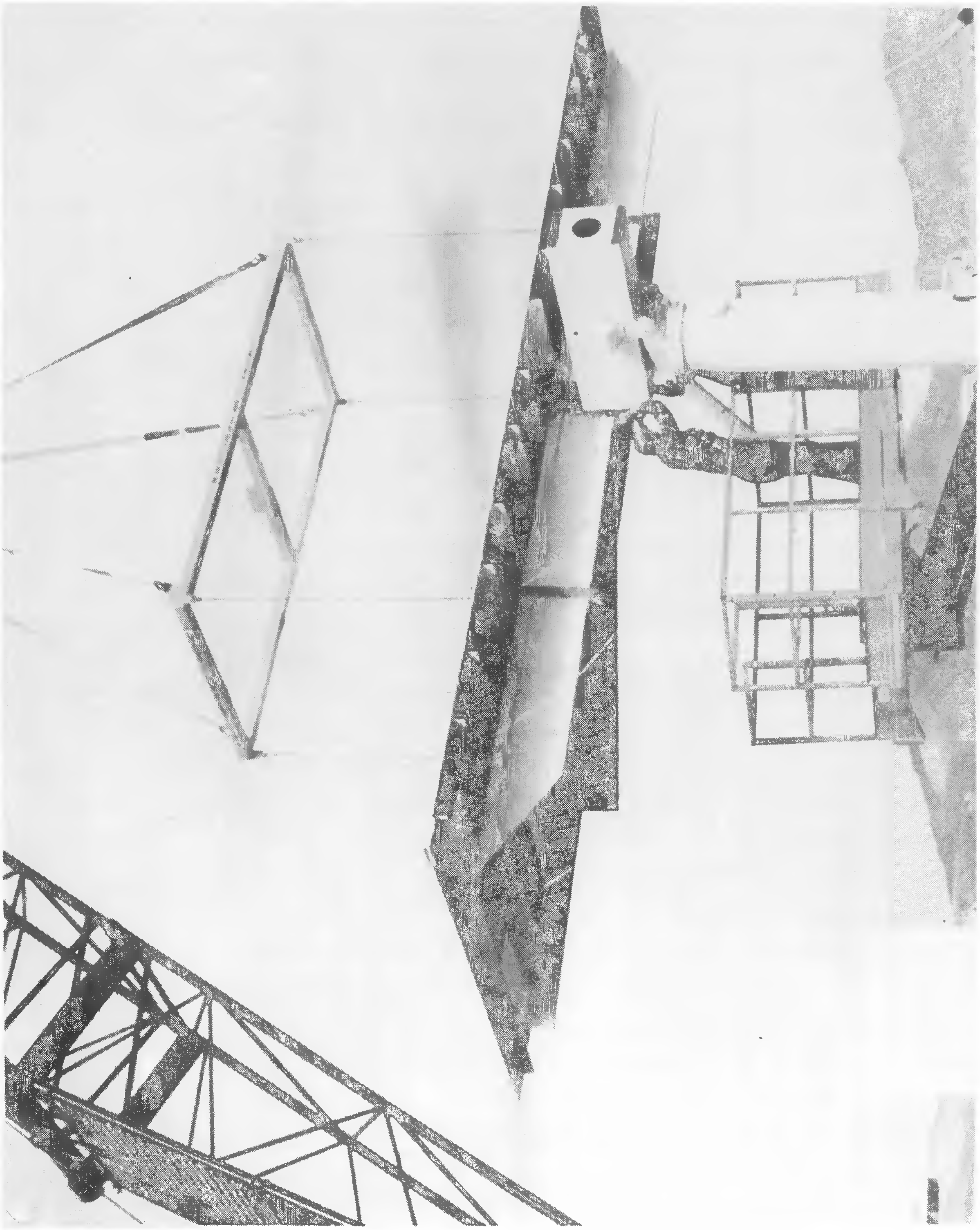
HELIOSTAT FIELD INTERFACES



VFN208

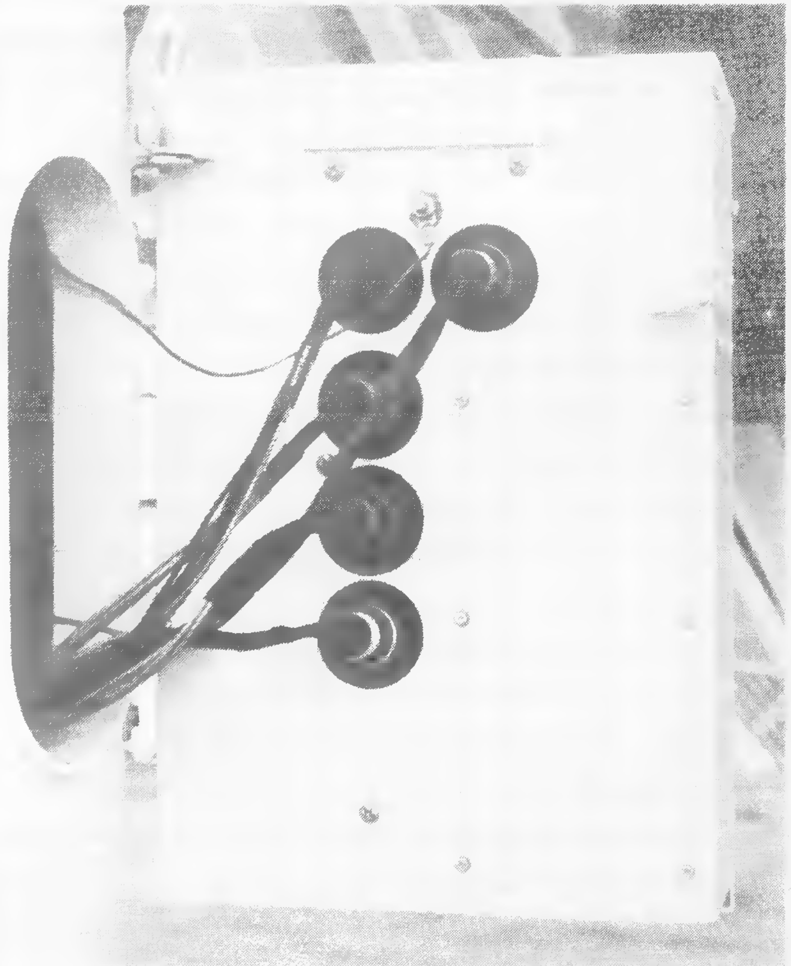
FOUNDATION INSTALLATION

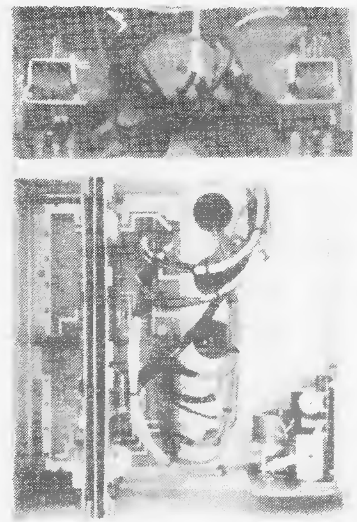




VFN228

HELIOSTAT CONTROLLER





SANDIA TESTING AND ANALYSIS OF THE SECOND GENERATION HELIOSTATS

W. R. Delameter
Sandia National Laboratories, Livermore

The Sandia evaluation of the Second Generation Heliostat designs was supported by an integrated program of testing and analysis consisting of:

- Prototype heliostat testing at the CRTF
- Mirror module testing
- Heliostat optical performance analysis with the HELIOS computer code
- Structural analysis with the SAP4 computer code
- Field performance analysis with the DELSOL computer code

The HELIOS and structural analyses were used to reduce the scope and cost of the test program by determining optical performance for a variety of field and sun positions and environmental conditions. Figure 1 shows the test results which are fed into both SAP4 and HELIOS. Results from SAP4 are used both directly and by HELIOS. HELIOS is ultimately used to determine whether the optical performance requirements are met.

The DELSOL field performance code was used at the beginning of the Second Generation program to determine the number of heliostats required for a 50 MWe field. Nominal performance parameters for beam pointing and beam quality were assumed. The DELSOL analysis will be rerun after the conclusion of the testing program using performance parameters based on measured values.

CRTF Testing

The purpose of the testing at the CRTF was to characterize the heliostats relative to the Second Generation design specification. Operational ability, optical performance, environmental survival, and projected life expectancy were assessed.

Two prototype heliostats of the ARCO, Boeing, and McDonnell Douglas designs were installed for testing at the CRTF in November, 1980. Martin Marietta installed their two heliostats in February, 1981. The heliostats were subjected to a series of 11 tests, which are summarized in Table I. The test program was scheduled to last three months. Testing of the ARCO, Boeing, and MDAC designs was mostly complete by March, 1981, and testing of

Figure 1. SECOND GENERATION HELIOSTAT ANALYSIS

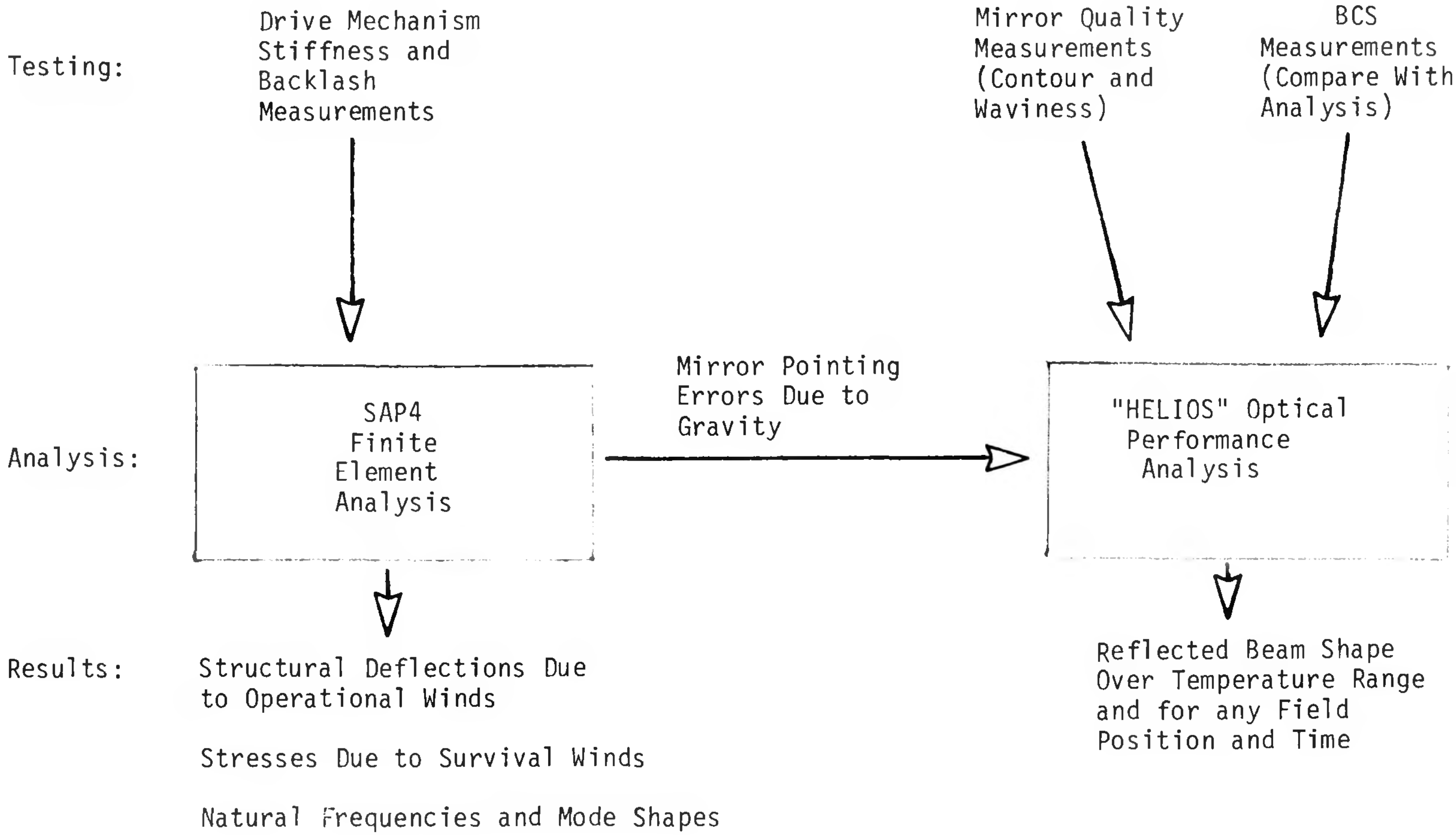


Table I. HELIOSTAT TESTING AT CRTF

Test	Purpose	Method
1. Operational Modes	• Determine that heliostat can perform required functions such as track, stow, standby, reference update, and assume a commanded position.	• Operate heliostat through required modes.
	• Determine power requirements.	• Measure power consumption during track and slew.
2. Beam Quality	• Determine compliance with beam quality specification.	• Measure reflected beam shape and determine performance parameters for HELIOS.
3. Pointing Accuracy	• Determine compliance with beam pointing accuracy specification.	• Measure beam centroid error for a full day at beginning and end of test program.
4. Heliostat Surface Accuracy	• Qualitatively assess reflective surface slope errors.	• Use "backward gazing" Heliostat Characterization System.
5. Life Cycle Testing	• Assess drive mechanism wear and control hardware problems for prolonged operation.	• Cycle heliostat continuously for six weeks, with slew to stow once each hour.
6. Pointing Accuracy with Operational Wind Loads	• Determine pointing error under steady wind loads for comparison with specification.	• Apply simulated wind loads while tracking and measure pointing error with BCS.
7. Wind Load Deflections	•Determine wind load deflections of structure, drive mechanism, pedestal, and foundation due to winds up to 50 mph.	•Apply simulated wind loads and measure deflections.
	•Assess survivability of structure and azimuth drive to 50 mph wind.	•Apply simulated wind loads and then recheck pointing accuracy.
	•Assess motor torque adequacy to drive against a 50 mph wind (both axes).	•Apply load and run motors at slew speed.
8. Survival Wind Load,	•Assess survivability of elevation drive mechanism and structure to 90 mph wind.	•Apply simulated wind load and then recheck pointing accuracy.
9. Water Spray, Disassembly	•Assess resistance to rain and wash water of drive mechanism and control box, and examine drive for wear.	•Spray heliostat with water before tear down and inspection.
10. Long-Term Operation	•Assess long-term performance, wear, and weathering characteristics.	•Operate heliostat at CRTF for one year with periodic inspection and performance evaluation.
11. Foundation Testing	•Characterize tilt and twist of pedestal/foundation during and after high wind loads.	•Apply simulated wind loads to top of pedestal after removal of drive and reflective structure, and measure deflections.

1

the Martin Marietta heliostats began in April, along with retests of ARCO and the Foundation Testing. Final testing, with the exception of the Long-Term Operation test, was completed in July, 1981.

Mirror Module Testing

Four extra mirror modules of each design were delivered; three to Sandia, Livermore, and one to the CRTF for laser ray trace and to serve as a spare for the heliostats. The mirrors were evaluated for optical performance, weatherability, and survival of wind, hail, and temperature extremes. A summary of the mirror module tests is given in Table II.

Structural Analysis

Each of the heliostat designs except Westinghouse was structurally modeled using the SAP4 finite element computer code. The purpose of these analyses was to provide information not readily available by testing about the performance and survivability of the designs.

The following were determined for each design:

1. Angular deflections of each mirror facet due to gravity as a function of heliostat evaluation angle. This information was used with HELIOS to assess reflected beam quality.

2. Structural deflections of the heliostats due to operational wind loads (up to 27 mph). The overall angular deflection of the reflective surface was limited in the design specification to 3.6 mrad (root-mean-square), discounting the foundation.

3. Critical stresses in the structure under survival wind load conditions.

4. Natural frequencies and mode shapes from the dynamic analysis of each design.

All of the loadings and resulting deflections in 1 through 3 above were assumed to be static. For these cases, the drive mechanisms were assumed to be rigid. Drive mechanism deflections were measured at the CRTF under simulated wind loads, and the measured deflections were combined with calculated values for the remainder of the structure to determine total deflections. The drive mechanisms were modeled as torsional springs for the dynamic analysis. The assumed spring constants were determined from measured deflection versus load curves.

The results of the structural analysis were as follows:

- Structural deflections due to gravity were found by HELIOS analysis to have only a slight impact on beam quality.

- All of the designs were found to be within the 3.6 mrad deflection requirement in a 27 mph wind.

Table II. MIRROR MODULE TESTING

Test	Purpose	Method
1. Contour Measurement	• Determine large scale mirror contour (focal length)	• Measure mirror shape with a matrix of linear displacement gages.
2. Wind Load Glass Stress	• Assess capability to survive 90 mph wind.	• Uniformly load module with weights and measure glass stress with strain gages.
3. Thermal Stress and Contour Change	• Determine temperature-induced glass stress and contour change.	• Measure contour and glass stress at different temperatures.
4. Residual Glass Stress	• Determine residual and fabrication stresses in the glass.	• Measure with reflection polariscope.
5. Gravity Sag	• Determine contour change due to gravity.	• Load mirror module uniformly with equivalent of its own weight and measure contour.
6. Thermal Cycling	• Assess capability to survive thaw-freeze cycling and temperature extremes.	• Cycle between -20°F and 120°F 112 times.
7. Environmental Cycling	• Assess weatherability of mirror module.	• Cycle temperature between 70°F and 130°F four times per day and vary humidity between wet and dry weekly, with continuous UV radiation.
8. Hail Test	• Determine compliance with hail requirement.	• Impact mirror module with ice balls.
9. Cold Water Shock	• Assess capability to survive cold wash or rain.	• Splash water on hot mirror.
10. Reflectivity	• Determine solar-weighted reflectance.	• Measure mirror modules and mirror samples with several reflectance instruments.
11. Laser Ray Trace	• Determine effective mirror waviness.	• Measure with laser ray trace technique.

- Stresses in the major structural components were found to be acceptable for each design.

- Natural frequencies were found to be above the frequencies which could be driven in a major vortex-shedding mode.

In summary, the structural analysis showed that each of the heliostats was well designed in terms of stiffness and strength.

Compliance with Requirements

The heliostat design specifications can be broken up into four categories: operational modes, optical performance, survival, and 30-year life. These requirements are briefly summarized in Table III.

The test program identified specific weaknesses in each heliostat design. The key findings are summarized in Table IV, along with potential solutions to the problems.

Overall, it was found that all four of the designs which were built and tested can meet the requirements with certain low-risk changes.

ARCO's main problems were the drive motors and the foundation. The motors need to be replaced with larger units having greater torque and slew rate capability. The vibration-installed foundation was an unsuitable concept for the soil at the CRTF. The concept did work in Dallas and at the CRTF until rocks were encountered. Grouting the ARCO foundation pipe in place or other foundation designs can easily be adapted to the ARCO heliostat.

Boeing's mirror module was shown to be unacceptable. Silver corrosion was found on five mirrors at the CRTF. Also, two mirrors cracked with no apparent external impact, indicating high thermal and/or fabrication stresses. Finally, the integrity of the core strength as well as protection of the mirror silver depends on the edge seal. Disassembly of one of the mirror modules revealed that a considerable amount of water had gotten through the edge seal, resulting in silver deterioration and debonding of the front and back sheets of glass from the core. Boeing should probably use a low-risk mirror module design such as one employing laminated glass. The Boeing pedestal/foundation was also seen to be unsuitable for the rocky soil conditions at the CRTF. As with ARCO, there are other foundation concepts (including grouting in place) which could be adapted to this heliostat design.

The major problems with the Martin Marietta design were the mirror module and the stow lock concept. The mirror module loaded to a 90 mph wind condition failed by debonding between the paper honeycomb and the back sheet. MMC reports that the bond was poor because the adhesive "skinned over" before the parts were mated. At the CRTF, cracks have appeared on three different mirrors. Furthermore, brown-stained water has been observed to run out of the modules at the CRTF when the heliostat is moved from a stow position. Inspection showed waterlogged, soggy,

Table III. HELIOSTAT DESIGN REQUIREMENTS

Operational Modes:	- Normal modes (track, standby, wire walk, stow) - Track to 35 mph wind - Slew in 50 mph wind - Resolve singularity in 15 minutes - Reposition in 15 minutes - Emergency defocus in 3 minutes - Electrical transients (3-cycle dropout)
Optical Performance:	- Beam pointing (1.5 mrad RMS maximum, reflected beam error for each axis) - Beam quality (theoretical beam shape plus 1.4 mrad fringe, 32°F - 122°F) - Wind load deflection (3.6 mrad RMS maximum reflective surface deflection in 27 mph wind, discounting foundation) - Foundation deflection (0.45 mrad maximum set after survival wind, 1.5 mrad maximum twist or tilt in 27 mph wind)
Survival:	- 90 mph wind, heliostat stowed - 50 mph wind, heliostat in any orientation - Temperature, -20° to 122°F - Hail, 3/4" at 65 ft/sec, any orientation 1" at 75 ft/sec, heliostat stowed - Cold water shock
30-Year Life:	- Life of all components must be cost-effective for 30 years - Mirrors and drive mechanism are critical components

Table IV. SUMMARY OF KEY TEST RESULTS

Contractor	Deviations from Spec	Potential Solution
ARCO	- Inadequate drive speed and torque	- Change motors
	- Marginal tracking accuracy	- Improve control system software
	- Marginal beam quality	- Mirror module production tooling may correct curvature
	- Foundation loose in ground	- Different foundation design required for some sites
BOEING	- Low mirror module life expectancy	- Use alternate mirror module design
	- Foundation loose in ground	- Different foundation design required for some sites
	- Wear on elevation drive jack	- Winsmith has developed an improved lubricant and has performed verification testing
	- Pointing error after 90 mph wind load	- Further testing and analysis required
MARTIN MARIETTA	- Low mirror module life	- Use alternate mirror module design
	- Inadequate motor torque for track and slew from non-production motors	- Install and test production motors
	- Feasibility of stow lock device not demonstrated on prototype or for production	- Redesign stow lock, or redesign drive to delete stow lock
	- Pointing error after 90 mph wind load	- Further testing and analysis required
MCDONNELL DOUGLAS	- None identified	

debonded honeycomb cores. The present design of this mirror module is unacceptable, and it is recommended that MMC use a low-risk concept, such as laminated glass, for near-term applications.

The MMC stow lock has not been demonstrated to be a feasible concept to use in production. Extremely tight tolerance controls and a fail-safe feature to prevent accidental damage are needed for the present design to work. Problems were encountered with the locking devices on both heliostats at the CRTF. Further development is needed before this design will work. Otherwise, the drive must be redesigned to take survival wind loads without the stow lock.

The McDonnell Douglas heliostat had no major deficiencies. The evaluation drive mechanism showed some wear after the life-cycling, as did the drives of all of the other designs but MMC's. Some design modifications and further testing have been performed by MDAC to assure a long life of the drive.

Overall, none of the problems which have been identified can be considered inherent ones which cannot be solved and which would not be considered typical in the course of the design evolution of heliostats.

Conclusions

The results of the evaluation show that with low risk design changes all of the four tested Second Generation Heliostats are viable designs. The four heliostats each have unique approaches to the same generic design with varying amounts of risk and additional development required. The inherent weakness of previous designs have all been eliminated by one or more of the new approaches. However, some relatively minor design changes or proven alternate approaches can benefit all of the heliostats.

HELIOSTAT FOUNDATION ANALYSIS

H. L. DAVIDSON
GAI CONSULTANTS, INC.

Contractural Information

- Contract Title:
  - Electric Power Research Institute (EPRI), Project RP 1280-1, Laterally Loaded Drilled Pier Study
  - Sandia National Laboratories, Livermore, Contract 20-4441, Analytical Model Development for Flexible Drilled Piers Subjected to Lateral Loads
- Sandia Contract Cost: $99,000
- Objective:

  Develop an improved design/analysis methodology for Laterally loaded pier foundations.

Overview of Project

A drilled pier foundation typically consists of a cylindrical, reinforced concrete pier which is constructed by augering a hole in soil and/or rock, inserting a reinforcing cage in this hole, and subsequently backfilling the hole with concrete. Other types of laterally loaded cylindrical foundations, such as pipe piles and precast concrete cylinder piles, can be analyzed and designed using the techniques described herein.

The drilled pier foundation is widely used to support transmission line structures due to its simplicity of construction. Cylindrical foundations such as drilled piers or pipe piles have also been proposed for heliostat foundations. Foundation design for single-pole transmission structures and for heliostats is typically controlled by lateral loads rather than vertical loads. Classical methods for predicting the load-deflection relationship for drilled piers consistently over-predict pier deflection and rotation, by as much as an order of magnitude.

As noted above, the fundamental objective of this project is to develop an improved design/analysis methodology for laterally loaded piers. To achieve this objective, the project was divided into the following five phases:

- Phase I - Critique current methodologies for the design/analysis of laterally loaded drilled piers and develop an improved methodology.
- Phase II - Develop a design/analysis computer program utilizing the improved methodology.
- Phase III - Conduct instrumented load tests on prototype drilled piers (EPRI test program).
- Phase IV - Develop theoretical predictions of the behavior of the test piers and compare with test results. Modify the design/analysis model and computer program, as appropriate, to obtain a best-fit to the field data.
- Phase V - Develop predictions of the behavior of piers tested outside of this project (including five heliostat foundations) using the modified model and computer program developed in Phase IV.

To develop a data base of high quality test results, a field testing program was conducted as part of this research project (Phase III). Fourteen prototype drilled piers were subjected to high ground-line moments, and 12 of these piers were tested to large ground-line deflections (EPRI test program). Thirteen of the tests were either co-sponsored or fully sponsored by various utilities in the United States. The first test was fully sponsored by EPRI and was conducted as a shakedown test. Test pier diameters ranged from 4.5 to 6.5 feet (1.4 m to 2.0 m) while pier lengths varied from 11.5 feet to 21.0 feet (3.5 m to 6.4 m). The ratio of embedded depth to diameter for the 14 piers ranged from 2.5 to 4.2. A majority of the piers were designed for a nominal ultimate lateral capacity of 2000 kip-ft (2700 kN-m).

Phase III was completed in the summer of 1980, while Phases I, II, IV and V were completed during the last 12 months.

Accomplishments during Previous 12 Months

In order to develop an accurate, yet computationally tractable technique for determining the ultimate capacity and load-deflection relationship of laterally loaded drilled piers, a subgrade modulus-like model was developed (Phase I). An initial theoretical linear load-deflection model was developed for the idealized problem of an elastic pier embedded in an elastic half-space, using dimensional analysis, coupled with three-dimensional, finite element parameter studies. The resultant linear, subgrade modulus-like formulation is referred to as the four-spring linear model, and is applicable to piers having a range of flexibilities from near-rigid to flexible which are embedded in multi-layered soils. An ultimate lateral capacity four-spring model was also developed. This model incorporates the ultimate lateral pressures developed by Brinch Hansen (1) and is conceptually similar to Ivey's model (2). Subsequently, a nonlinear four-spring, load-deflection and ultimate capacity model was developed. This model incorporates the above linear model and ultimate capacity model as well as a variation of Reese's p-y curves (3). Finally, this nonlinear model was modified to give a reasonable fit to the field data developed in this project (Phase IV). The resultant model is referred to as a semi-empirical design model and is shown schematically in Figure 1.

Using the semi-empirical nonlinear design model described above, a design/analysis computer program for laterally loaded drilled piers was developed (Phase II). PADLL (Pier Analysis and Design for Lateral Loads) can treat both flexible and nearly rigid pier-type foundations embedded in multi-layered subsurface profiles. PADLL incorporates the four-spring model in combination with a finite beam element model for the pier. Analysis options include ultimate capacity analysis and non-linear load-deflection analysis. In addition, the computer program can design (select depth and diameter) a pier to satisfy one or more of the following performance criteria:

1. The total deflection at the top of the pier is less than some tolerable deflection under a specified set of loads;

2. The permanent (non-recoverable) deflection at the top of the pier is less than some tolerable deflection following unloading from a specified set of loads;

3. The total rotation at the top of the pier is less than some tolerable rotation under a specified set of loads; and

4. The permanent rotation at the top of the pier is less than some tolerable rotation following unloading from a specified set of loads.

To further verify the semi-empirical design model, the computer program PADLL was used to develop ultimate capacity and load-deflection predictions for other piers tested outside of this project, including five second generation heliostatat foundations at Sandia's Central Receiver Test Facility (CRTF) in Albuquerque (Phase V).

Analysis of Heliostat Foundations

GAI Consultants conducted a subsurface investigation with pressuremeter testing and laboratory testing at the CRTF site to permit development of idealized subsurface profiles and to provide strength and stiffness material parameters for the soil. Two idealized subsurface profiles were developed and were used to

Table 1

Design Loads and Performance
Criteria for Martin Marietta Foundation

Load Case	Loads* Bending Moment (ft-lb)	Loads* Shear Force (lb)	Loads* Vertical Force (lb)	Performance Criteria* Total Tilt (mRad)	Performance Criteria* Residual Tilt** (mRad)
27-mph wind head on	17,160	1,144	9,000	1.5	-
50-mph wind head on	58,848	3,923	9,000	-	0.45

* at ground line
** following removal of specified loads

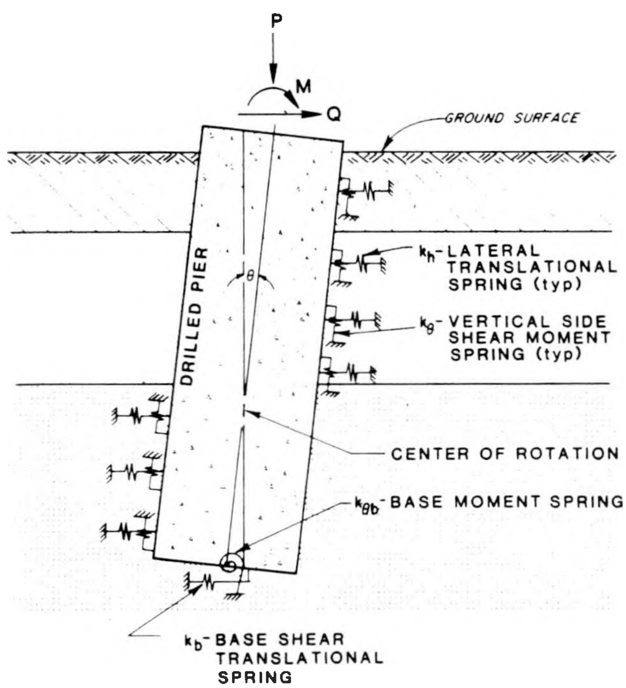


Figure 1. Four-Spring Subgrade Modulus Model

predict the response of the test piers to the loads applied in the field testing program at the CRTF. Predictions and test data for these piers are presented in this paper.

Test data and predictions for Boeing Heliostat Foundation No. 2 are presented in Figure 2. Data at four load levels are plotted in Figure 2. The moment was cycled three times at each load level in this test from positive to zero to negative and back to zero, prior to increasing the load level. The rotations plotted in Figure 2 correspond to rotations measured in the first cycle. It is noted that an initial rotation was measured under no load at the start of this load test, corresponding to a residual rotation induced by previous load tests. In this regard, all rotations are related to a zero reading taken prior to application of the first load test. As can be seen in Figure 2, PADLL yielded predicted rotations for Boeing Foundation No. 2 that agreed quite well with the measured rotations.

Test data and predictions are presented for Martin Marietta Heliostat Foundation No. 2 in Figure 3. The predicted rotations are approximately 70 percent higher than the measured rotations.

Test data and predictions for Boeing Heliostat Foundation No. 1, McDonnell Douglas Heliostat Foundation No. 1, and Arco Heliostat Foundation No. 2 are presented in Figures 4, 5, and 6, respectively.

The following preliminary conclusions can be drawn from the heliostat foundation testing program.

- Foundation behavior was typically essentially linear over the range of loads applied to the test foundations (maximum test loads were on the order of one to four percent of the theoretical ultimate lateral geotechnical capacities of these foundations).

- Although not shown in Figures 2 through 6, the rotations at the tops of the piers were essentially fully recoverable following unloading, and this was corroborated by PADLL.

- Analytical predictions, using PADLL, for rotations at the tops of the foundations were within a factor of two relative to the measured rotations for four of the five foundations.

Heliostat Foundation Design

PADLL was used to design a drilled pier foundation for the loads and performance criteria shown in Table 1. The load magnitudes are essentially those associated with the Martin Marietta heliostat. The performance criteria (total and permanent tilt) were required for all second generation heliostat foundations. The design was based on the same idealized subsurface profile used in the analysis of the Martin Marietta Foundations No. 2.

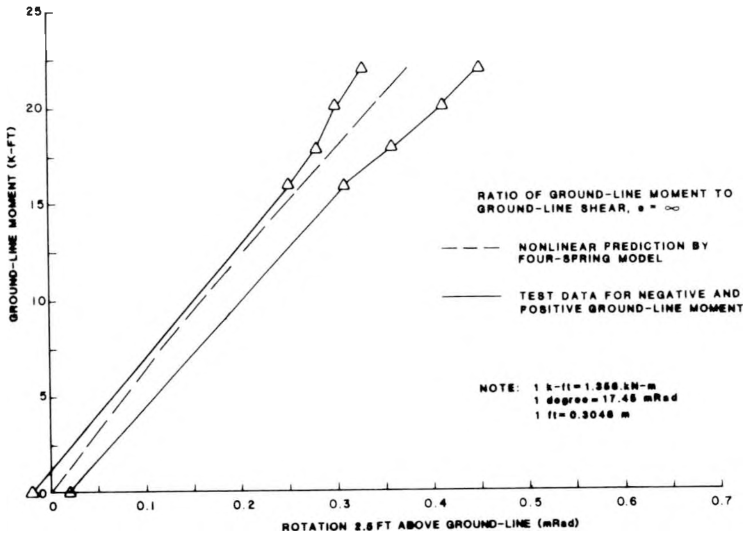


Figure 2. Load-Rotation Curve and Four-Spring Model Predictions, Boeing Heliostat Foundation No. 2

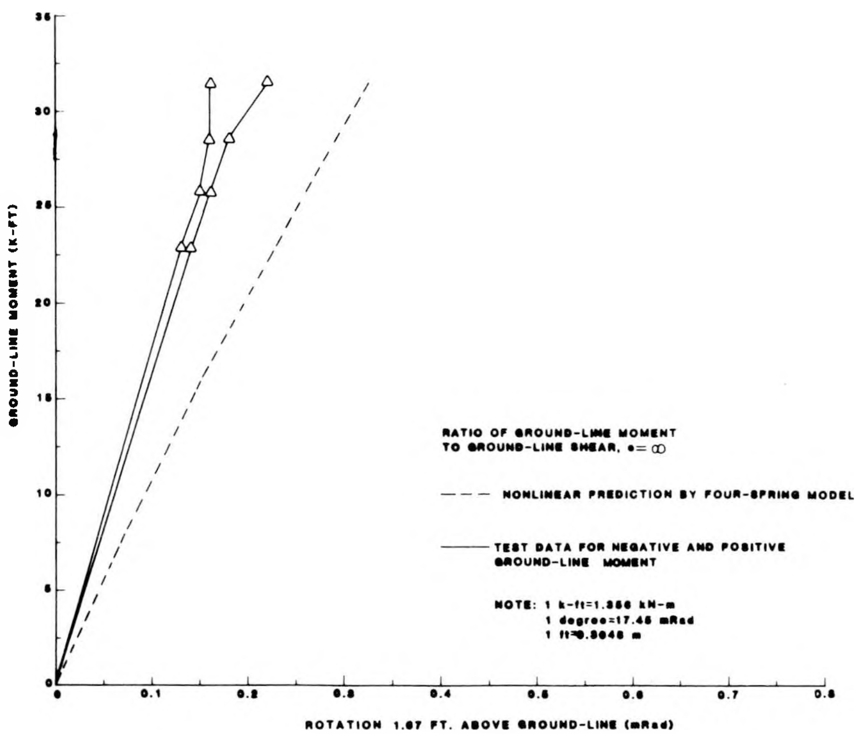


Figure 3. Load-Rotation Curve and Four-Spring Model Predictions, Martin Marietta Heliostat Foundation No. 2

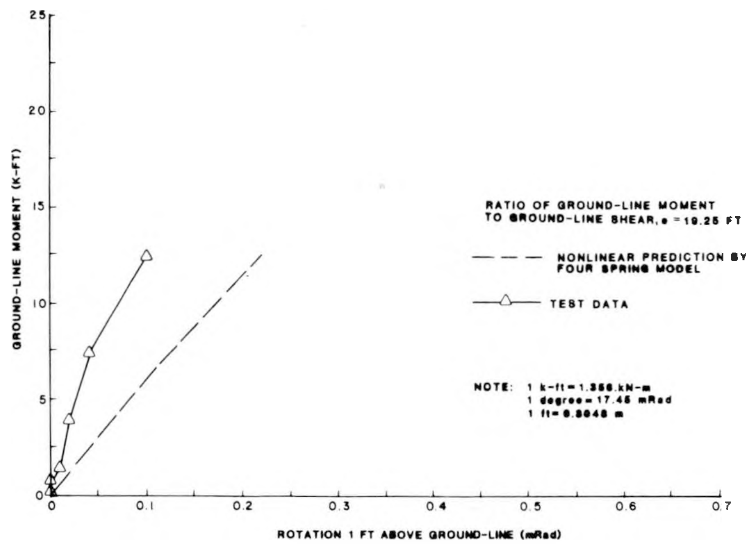


Figure 4. Load-Rotation Curve and Four-Spring Model Predictions, Boeing Heliostat Foundation No. 1

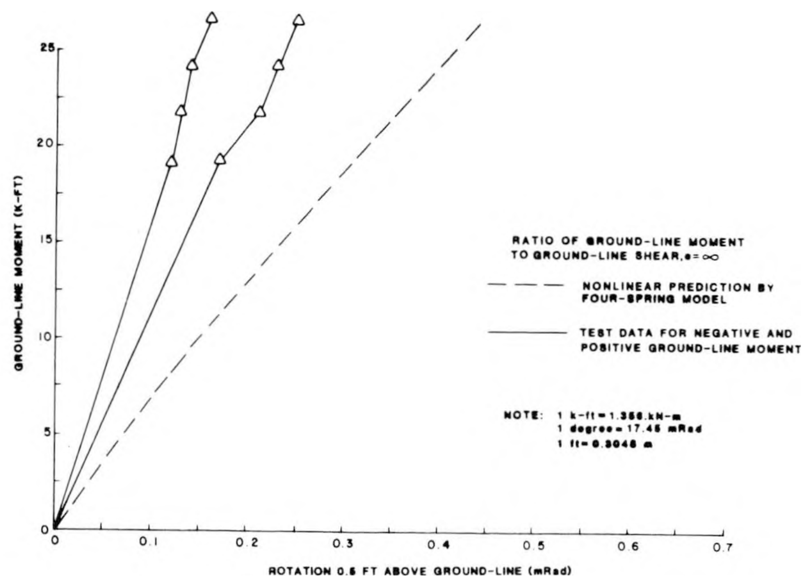


Figure 5. Load-Rotation Curve and Four-Spring Model predictions, McDonnel Douglas Heliostat Foundation No. 2

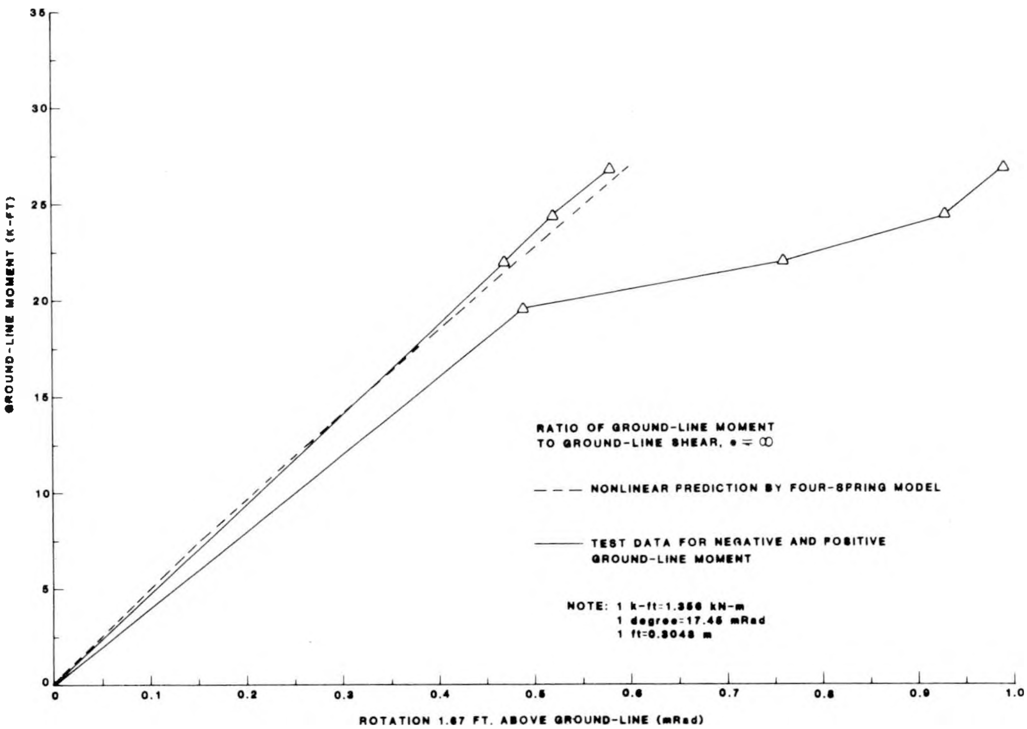


Figure 6. Load-Rotation Curve and Four-Spring Model Predictions, Arco Heliostat Foundation No. 2

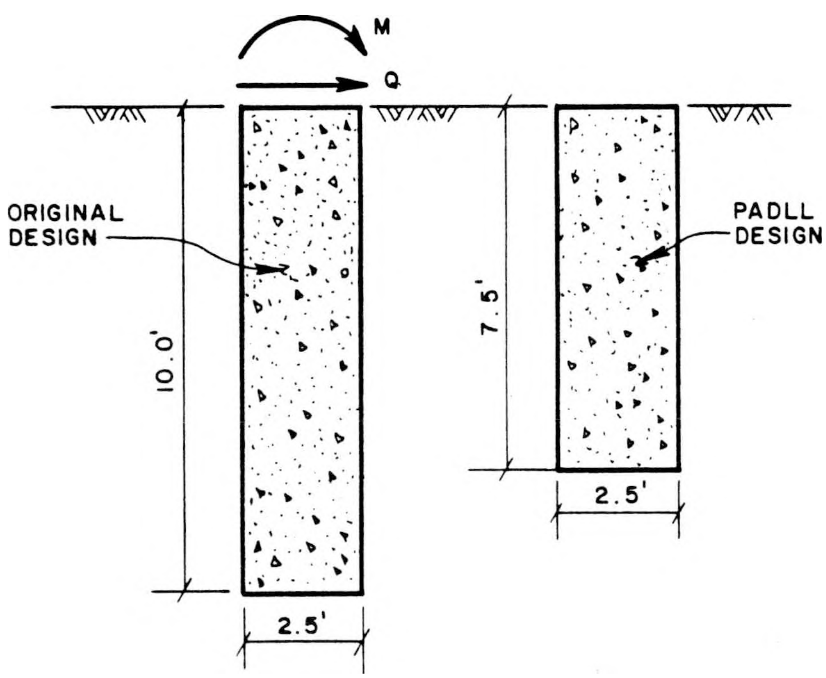


Figure 7. Pier Designs for Martin Marietta Heliostat

Referring to Figure 7, the resultant design dimensions are a diameter of 2.5 feet and a length of 7.5 feet. This compares to the original Martin Marietta design having a diameter of 2.5 feet and a length of 10 feet. Thus the pier designed using PADLL requires 25 percent less concrete than the original design. The PADLL design was based on a minimum specified diameter of 2.5 feet and was controlled by the permissible residual tilt following a 50-mph wind.

If the Martin Marietta pedestal were modified to accept a two-foot diameter drilled pier, the design length at a two-foot diameter would be 8.0 feet, corresponding to a 50 percent reduction in concrete volume as compared to the original design.

Conclusions

PADLL can predict with reasonable accuracy the lateral-load behavior of heliostat pier-type foundations. It appears that smaller piers than currently proposed for second generation heliostats may be appropriate.

References

1. Brinch Hansen, J., "The Ultimate Resistance of Rigid Piles Against Transversal Forces," The Danish Geotechnical Institue Bulletin, No. 12, 1961, pp. 5-9.

2. Ivey, D. L., "Theory, Resistance of a Drilled Shaft Footing to Overturning Loads," Texas Transportation Institute, Research Report No. 105-1, February 1968.

3. Reese, L. C., and Welch, R., "Lateral Loading of Deep Foundations in Stiff Clay," Journal of Geotechnical Engineering Division, ASCE, Vol. 101, No. GT7, July 1975, pp. 633-649.

ANTISOILING COATINGS FOR MIRRORS

Bernard Baum, Ph. D.

Springborn Laboratories, Inc.
Enfield, Connecticut

Introduction

The solar central receiver system uses large surface areas of glass in the field of heliostats to collect and focus light. Any loss of reflectance as a result of dirt depositing on the mirror surface will cause a loss of power and require maintenance by washing. However, in desert areas where such systems will be constructed, the ecology places limitations on the volume of water which may be used in such washing procedures. The objectives of this project were to develop methods for preventing or minimizing soiling of the surface of the glass-mirrored heliostat and the plastic dome over the aluminized Mylar mirror and also to facilitate the cleaning process. Such systems must have high clarity, be permanent, i.e. unaffected by the environment, and low in cost. The substrates used in this project were float glass, Kynar (polyvinylidene fluoride), and Petra A polyester.

There are two general approaches that were used to provide a surface with dirt-repellant properties:

(1) Reaction of an antistatic or soil-release agent either directly with the surface or through an intermediate coupling agent.

(2) Binding of the additives to the surface through a polymeric coating.

The two general classes of compounds which have been investigated were antistatic and antisoiling agents. Previous experience in plastics, textile, and metal technology has proven the usefulness of these materials for preventing or minimizing soiling. The four general categories of antistatic agents are amine derivatives, quaternary ammonium salts, phosphate esters, and polyethylene glycol esters. Soil-release agents are either hydrophilic ionic or hydrophilic nonionic in character. These compounds were attached to the substrate surface by silane or titanate coupling agents or as a mixture with a hard, weather-resistant coating. Some additional materials are also available which react directly with the glass or plastic and may function as antistatic agents.

Commercially available silane coupling agents, which have two reactive functional groups, are quite effective in reactive polymer systems. Hydrolyzable alkoxy groups attached to a silicon atom react with the hydroxyl or other functional group on the surface of the substrate. Also attached to the silicon atom is an organo functionality such as an amino, mercapto, epoxy, vinyl, or methacryloxy group which can react with specific antistatic or antisoiling agent. The amino functionality is reactive with epoxy, phenolic, nylon, and vinyl polymers, and with some thermoset elastomers.

The vinyl and methacryloxy silanes react with unsaturated polyesters and peroxide-cured polyethylene, for example. To be effective in any given system, the coupling agent must be reactive to some degree with both the polymer and the glass, or other substrate.

Titanates also interact with, and act as a bridge between the glass or plastic substrate and organic materials. They have three reactive pendant functional groups, and as with silanes they form a monomolecular layer on the surface. A typical reaction would be:

$$\text{Glass} - OH + RO - \overset{RO}{\underset{OR}{Ti}} - OR \rightarrow \text{Glass} - O - \overset{O}{\underset{O}{Ti}} - O -$$

Another route is the dispersion or solution of the antistat or soil-release agents in a polymeric coating. Only three classes of coatings or their modifications are weather (UV) resistant; acrylics, silicones, and fluorocarbons. The expense of the fluorocarbons is prohibitive; therefore, we have examined acrylics and silicones. The antistatic and soil-release agents were dispersed in the organic coating and the coating was bonded directly to the glass or plastic.

Experimental

Evaluation of the various coatings on the three substrates was accomplished by a sequential screening procedure. The tests were performed in the following order with ineffective materials eliminated at each step: (1) clarity, (2) adhesion, (3) antisoiling properties, (4) abrasion resistance, (5) antistatic properties, and (6) permanence.

Visual clarity of a coating is evaluated initially. Materials which obviously produce cloudiness or a haze on the substrate were discarded. Percent transmission, normalized to solar energy wavelengths, was measured before and after soiling tests on treatments of interest.

Our determination of adhesion is essentially subjective. Glass coatings are rubbed with a plastic rod to determine if the coating can be defaced or removed. Since both plastic substrates are too soft for this approach, we rubbed them with cheesecloth for the same determination.

The soil release test is accomplished by sifting AC Fine Mix Test Dust[1] from General Motors onto a coated sheet. The sheet is placed horizontally in the path of air from a hand-held air gun. The approximate amount of dust removed is estimated. Percent transmission is measured on samples which appear to be satisfactory. Two other methods of dust removal were used initially - air gun plus brushing with a soft camel hair brush and washing with a stream of deionized water from a squeeze bottle. Later in the program a water wash apparatus that could operate at varying pressure was designed and built.

---

(1) Arizona Road Dust

Three types of dust were evaluated: dry dust, oily dust (dust mixed with 3% Nujol) and humified dust (the dusted slide is humidified for 24 hours at 80% relative humidity).

Abrasion was determined by the falling sand method. Ten pounds of sand is dropped through a tube 30 inches long to the sample which is placed at a 45° angle. This is followed by the soil-release test to determine if the coating has been removed.

Permanence was measured by outdoor exposure and the RS-4 Sunlamp.

Discussion

Activation

Unlike glass, Petra A (thermoplastic polyester) does not have reactive functional groups on the surface. In order to attach coupling agents to this material it is necessary to activate the surface. Polyesters can be activated by hydrolysis of the ester linkage with a dilute sodium hydroxide solution (NaOH). The primary concern is to activate the surface without reducing the percent transmission of light through the material. We have found that exposure to Petra A to a 10 percent solution of NaOH for two hours at room temperature caused no loss of transmission.

Kynar also has no functional groups on the surface that would promote reaction. Kynar may be activated by dehydrofluorination using a primary amine in a solvent such as methanol. The best technique involved immersion in 10 percent butyl amine in methanol for five minutes followed by reflux for two hours at 65°C in a 1.0% acetyl peroxide solution in methanol.

Glass

It is essential that the reagents being attached or coated on the glass have negligible effect on transmission. Untreated glass has a solar transmission of 87% and none of the treatments lower transmission by more than one percent.

Using a broad variety of antistats and soil release agents with coatings and coupling agents, Arizona Road Dust was sifted onto the coated glass slide (non-tinned side), tapped to remove excess dust and blown with an air gun. Dusted glass loses 5% transmission dropping from 87 to 82%.

Excellent results were obtained, as shown in Table 1, with three systems:

(1) The silicone, Glass Resin 650 (Owens Illinois)

(2) General Electric's Q3-6060 silicone resin followed by Monsanto's Santicizer 141, a phosphate ester antistatic agent

(3) Hydroxyethyl cellulose soil release agent coupled with duPont's titanate, Tyzor TE.

Table 1

Percent Transmission of Best Coating Systems on Glass After Dust Removal with Air Gun

Coating System	Dry Dust	Oily Dust	High R.H. Dust
Untreated Glass[1]	82	81	74
Q3-6060/141	86	86	86
Glass Resin 650	86	85	80
HEC/TE[1]	84	84	83

(1) Hydroxyethyl Cellulose/Tyzor TE

Table 2

Percent Transmission of Coated Petra A[1] After Dust Removal

Coating	Prior[1] To Dusting	Air Gun			Air Plus Water Wash
		Dry	Oily Dust	High RH	Dry Dust
Control	83	78	77	77	81
650 Glass Resin	87	80	83	81	87
WL-81	85	80	81	-	85

(1) % T of dry dusted but uncleaned Petra A is 76%

All three systems effected considerable improvement with dry, oily and humid dust removal by air gun.

Petra A and Kynar

Coatings on activated Petra A not only permitted a more efficient dust removal (Table 2) but also improved the initial percent transmission. The 650 Glass Resin coating gave a 4% increase in initial transmission and the Rohm and Haas acrylic latex, WL-81, 2%. As expected, an air stream used in conjunction with a stream of water (from a laboratory wash bottle) was the most effective of the three dust removal methods.

The only system that was effective with Kynar was Glass Resin 650. Dust removal was more efficient for dry, oily and humid dust with all three methods of dust removal, i.e. air gun, air gun plus brush and air gun plus a water stream using coated glass.

Coating Permanence

Although a number of coatings have proven effective in developing a surface for easier dust removal, the dust removal test has only been carried out once. What would be the effect, as would occur in practice, of many cycles of dusting and dust removal? Would the coating still be efficient?

To evaluate the effect of multiple dusting and dust removal coated glass, Petra A and Kynar substrates were dusted with Arizona Road Dust 12 times with air cleaning in between each one. With repeated dustings the cleaning by air blowing became ineffective. There was a steady build-up of unremoved dust. Therefore, the approach was changed and washing with a lab wash bottle was introduced at the completion of 12 dust and air removal steps. This was considered as one cycle.

After repeated dustings and dust removal the silicone 650 Glass Resin coating provided more easy dust removal on both glass and Petra A (Table 3).

A limited study was carried out on the effect of outdoor weathering on both reflection and transmission. After six weeks exposure reflectance of second surface mirrors coated with 650 Glass Resin was identical with that of the control as was the transmission of 650 Resin coated float glass. With both Petra A and Kynar, polymer coatings (WL-81-for the former, and 650 Glass Resin for the latter) were less affected than was the uncoated substrate. Both coatings were not only proving stable but were protecting the substrate (Table 4).

Water Wash Apparatus

Three methods of dust removal have been used throughout this program:

(1) Air stream from an air gun

(2) Air gun while brushing with a soft destaticized (with Santicizer 141) brush

Table 3

Percent Transmission

After Multiple Dustings

Substrate	Coating	% Transmission(1) Original	After One Cycle (2)	Two Cycles
Glass	650 Glass Resin	87	85	86
	Uncoated Control	87	79	83
Petra A	650 Glass Resin	87	86	88
	Uncoated Control	83	78	78
Kynar	650 Glass Resin	87	86	86
	Uncoated Control	86	85	86

(1) Measured from 350 to 900 nm (direct)
(2) 12 Dustings with air removal in between each dusting with final air plus water wash.

Table 4

Effect of Outdoor(2)

Weathering on Transmission

Substrate	Coating	% Transmission(1) Orginal	6 Weeks
Float Glass	650 Resin	87	87
	Uncoated	87	87
Petra A	UL-81	85	85
	Uncoated	83	83
Kynar	650 Resin	87	85
	Uncoated	87	82

(1) From 350 to 900 nm
(2) Hazardville, Ct.

(3) Washing with a stream of water from a laboratory, plastic squeeze wash bottle.

None of these are quantitative and precisely reproducible techniques. Therefore, in consultation with Sandia Livermore, we designed a water wash apparatus. It is basically a pressurized holding tank with a controlled orifice valve. Water is sprayed through the valve onto a sample holder. Variables are water pressure, valve orfice, spray time, distance of the sample from the valve, and specimen angle. All variables were fixed except for time and pressure.

Arizona Road Dust was sieved onto float glass mirrors through the usual 40 mesh sieve and the excess dust tapped off. The dusted samples were washed in the water wash apparatus at various pressures and times and percent reflectance measured. Reflectance before dusting varies from 71-75.

It is obvious that even at the lowest water pressure and shortest times, i.e. 2 psi and 7 seconds the dust is removed and reflectance generally returned to the original value. Dust that has not weathered on a substrate is not "cemented" and is, as discussed above, easily removable.

In a further effort to study the effects of outdoor aging as well as to evaluate the Water Wash Apparatus, float glass and 650 Glass Resin coated float glass were put under the General Electric RS-4 sunlamp. Percent transmission was measured after 2 and 6 weeks, before and after washing (Table 5). With both dry and oily dust the 650 Glass Resin coating minimized dust pick up on float glass and with dry dust facilitated dust removal during washing (Table 5).

Costs

The ultimate criteria for judging the results of this work is cost-effectiveness of the coating systems. In the context of this program a technically effective coating would minimize the number of washings needed to remove dust.

The first step is to calculate the cost of coating glass heliostats, as well as the Petra A and Kynar domes. The assumptions used in calculating the cost of coating heliostats included both variable and fixed costs. Coating cost for the Petra A dome is more than double glass mirror coating cost primarily because of the cost of activation (Table 6). Activation of Kynar is even more complex and even more costly.

Table 6 also defines washing costs. An assumption of $1.50/heliostat and 26 washes/year=$39/heliostat/year or 39,000,000 for the cost of 50,000 heliostats over 20 years.

The ultimate judgement lies in the assumptions that the coating could reduce the number of washings to 1/2 or to 3/4. Comparisons are made with a coating life of 10 and 20 years. Column 1 of Table 7 gives the cost/ over a 20 year period/heliostat, with washing costs at 26 times/year at the top. The final column reveals that the savings with each of these assumptions varies from a low of $7,650,000 (10 year life, 1/4 of the washings

Table 5

Effect of RS-4 Sunlamp Aging On Soil Removal
From Coated Glass Using the Water Wash Apparatus

Period of Exposure In Weeks	Type of Dust (1)	Percent Transmission of Dusted Samples			
		Before Washing		After Washing (3)	
		Glass Control	Coated (2) Glass	Glass Control	Coated Glass
0	Dry	80	-	-	-
2	Dry	71	87	85	89
6	Dry	79	85	86	88
2	Oily	72	83	86	85
6	Oily	82	85	87	87

(1) Arizona Road Dust put on before aging

(2) 650 (Silicone) Glass Resin

(3) 5 psi for 15 seconds

Table 6

Costing Cost/Heliostat

	25,000	50,000
Glass Mirrors	22.13	20.80
Petra A Dome	50.35	46.20
Kynar Dome	57.00	54.20

Water Wash Cost

$1.50/Heliostat x 26 Times/yr

=$39/Heliostat/yr

x 20 Years = $780

x 50,000 Heliostats

= $39,000,000

Table 7

Comparison of Washing Costs:

Coated vs Uncoated

Assumption (1)	\$ Costs (3) /20 Years Per Heliostat	\$ Savings Over 20 Years (5)
Washing Only No Coating	780 (4)	-
1/2 as Many Washes-20 yr. Costing Life	411	18,450,000
1/2 as Many Washes-10 yr. (2) Coating Life	432	17,400,000
3/4 as Many Washes-20 yr. Coating Life	606	8,700,000
3/4 as Many Washes-10 yr. (2) Coating Life	627	7,650,000

(1) 50,000 heliostats/year

(2) Two coatings/20 years

(3) Rounded off to nearest dollar

(4) 26 washings/year at \$1.50 washing/heliostat

(5) Compared to \$780/heliostat x 50,000 heliostats or \$39,000,000/20 years

eliminated because of the coating) to a high of $18,4500,000 savings (20 year life, 1/2 of the washings eliminated). A 10 year coating life assumes that the coating will be replaced at the end of 10 years. Savings are based on a comparison with the cost of $39,000,000 for washing 26x per year for 20 years.

For example, on a full washing schedule of 26x/yr the cost/heliostat/ 20 years is $780. If we assume only 1/2 the number of washings, the washing cost is $390 plus $20.80 coating cost or $411/heliostat. For 50,000 heliostats the total cost is $20,550,000. The savings are $39,000,000 - 20,550,000= $18,450,000.

Problem Areas

The principal problem lies in the determination of washing effectiveness for coated vs uncoated substrates where dust has accumulated under realistic outdoor conditions. At what rate does dust accumulate outdoors at various locations? How much less dust accumulates on specific coated substrates? In light of current theories that under the combined action of UV, moisture, and salts dust is "cemented" to the substrate, will washing continue to remove all accumulated dust?

UNLIMITED RELEASE

INITIAL DISTRIBUTION

UC - 62c (200)

U. S. Department of Energy
James Forrestal Building
1000 Independence Avenue, SW
Washington, DC 20585
Attn: F. Morse
G. W. Braun
W. W. Auer
S. Cherian
G. Greyerbiehl
M. Gurevich
J. Langehorst
C. Mangold
C. McFarland
J. Rannels
D. Stogoski
H. Swisher

Albuquerque Operations Office
U. S. Department of Energy
P.O. Box 5400-SPD
Albuquerque, NM 87115
Attn: G. N. Pappas
J. Weisiger

Solar Energy Division
U. S. DOE/SAN Office
1333 Broadway
Oakland, CA 94612
Attn: S. E. Elliott
R. W. Hughey
W. Kaspar
K. Rose

R. N. Schweinberg
San Francisco Operations Office
Solar Ten Megawatt Project Office
5301 Bolsa Avenue, MS14-1
Huntington Beach, CA 92647

G. Brandvold, 4710
J. V. Otts, 4721
T. B. Cook, 8000; Attn: A. N. Blackwell, 8200
B. F. Murphey, 8300
Department, 8120
R. J. Gallagher, 8124; Attn: M. J. Fish, 8124
J. Kraabel, 8124
Division, 8328; Attn: L. Brandt, 8328

L. Gutierrez, 8400; Attn: R. A. Baroody, 8410
W. E. Alzheimer, 8440
C. M. Tapp, 8460

R. C. Wayne, 8430
J. F. Genoni, 8450
C. S. Selvage, 8450
C. T. Yokomizo, 8451
A. C. Skinrood, 8451 (250)
W. G. Wilson, 8453
Publications Division, 8265/Technical Library Processes and Systems Division, 3141
Technical Library Processes and Systems Division, 3141 (3)
Education Division, 8214 (3)