EVALUATION OF LINE FOCUS SOLAR CENTRAL POWER SYSTEMS

Volume 2, Systems Evaluation

MASTER

March 15, 1980

Work Performed Under Contract No. EY-76-C-03-1101-014

The Aerospace Corporation
Energy and Resources Division
El Segundo, California

U.S. Department of Energy

DIST 258
NTIS 25

2201

Solar Energy

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DISCLAIMER

"This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy \$14.00
Microfiche \$3.50

EVALUATION OF LINE FOCUS
SOLAR CENTRAL POWER
SYSTEMS

Volume II
Systems Evaluation

Prepared for
U.S. DEPARTMENT OF ENERGY
Solar Energy Division, DOE/SAN

Contract No. EY-76-C-03-1101(PA #14)

15 March 1980

Energy and Resources Division
THE AEROSPACE CORPORATION
El Segundo, California 90245

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

CONTENTS

	<u>Page</u>
FOREWORD	xii
1. INTRODUCTION.	1-1
1.1 PROGRAM OBJECTIVES.	1-1
1.2 STUDY APPROACH.	1-2
1.3 CONTRACTORS AND TECHNICAL MANAGEMENT.	1-3
1.4 SUMMARY.	1-5
2. SYSTEM DESCRIPTION.	2-1
2.1 SYSTEM REQUIREMENTS	2-1
2.2 PLANT DESIGN DESCRIPTION	2-2
2.2.1 BDM Plant Description	2-2
2.2.2 GA Plant Description	2-6
2.2.3 SRI Plant Description	2-9
2.3 SYSTEM PERFORMANCE AND COST	2-12
2.3.1 Outline of Calculation	2-12
2.3.2 Performance Comparison	2-12
2.3.3 Capital Cost Comparison.	2-14
2.3.4 Contractor Busbar Energy Cost (BBEC) Summary	2-17
2.4 PLANT DESIGN EVALUATION	2-20
3. SUBSYSTEM DESCRIPTION	3-1
3.1 COLLECTOR SUBSYSTEMS	3-1
3.1.1 BDM Collector Subsystem	3-1
3.1.2 GA Collector Subsystem	3-1
3.1.3 SRI Collector Subsystem	3-4
3.1.4 Collector Subsystem Evaluations	3-4
3.2 RECEIVER SUBSYSTEM	3-7
3.2.1 BDM Receiver Subsystem	3-7
3.2.2 GA Receiver Subsystem	3-7
3.2.3 SRI Receiver Subsystem	3-7
3.2.4 Receiver Subsystem Evaluation	3-7
3.3 HEAT TRANSPORT SUBSYSTEM	3-10
3.3.1 BDM Heat Transport Subsystem	3-10
3.3.2 GA Heat Transport Subsystem	3-11
3.3.3 SRI Heat Transport Subsystem	3-11
3.3.4 Heat Transport Subsystem Evaluation	3-11
3.4 ENERGY STORAGE SUBSYSTEM	3-11
3.4.1 BDM Energy Storage Subsystem	3-11
3.4.2 GA Energy Storage Subsystem	3-15
3.4.3 SRI Energy Storage Subsystem	3-15
3.4.4 Thermal Storage Subsystem Evaluation.	3-15
3.5 ELECTRICAL POWER GENERATING SUBSYSTEM	3-15
3.5.1 BDM EPGS	3-15
3.5.2 GA EPGS	3-15

CONTENTS (Continued)

	<u>Page</u>
3.5.3 SRI EPGS	3-18
3.5.4 EPGS Evaluation	3-18
4. PERFORMANCE AND COST EVALUATION	4-1
4.1 EVALUATION APPROACH.	4-1
4.2 COST AND PERFORMANCE NORMALIZATION	4-1
4.2.1 Performance Normalization	4-3
4.2.2 Cost Normalization	4-11
4.3 BUSBAR ENERGY COST COMPARISONS	4-23
4.3.1 First Order Busbar Energy Cost Comparison	4-25
4.3.2 Busbar Energy Cost Comparison Using Normalized Line Focus Data	4-28
5. LINE FOCUS APPLICATIONS	5-1
5.1 LINE FOCUS MARKET DESCRIPTION	5-1
5.1.1 Line Focus Market Size	5-1
5.1.2 User Temperature Requirements	5-4
5.1.3 Study of Cost Penalties Associated with Variations in Field Dimensions	5-4
5.2 "COMBINED" LINE FOCUS ELECTRICAL POWER SYSTEM	5-9
5.2.1 System Evolution	5-12
5.2.2 Selection of the Preferred System Configuration	5-14
5.2.3 Conceptual Design	5-15
5.2.4 "Combined" Plant Summary	5-18
5.3 HYBRID POWER SYSTEM	5-18
5.3.1 Study Approach	5-19
5.3.2 System Configuration	5-19
5.3.3 Hybrid Plant Energy Costs	5-21
5.4 LINE FOCUS SOLAR REPOWERING.	5-21
5.4.1 Repowering Benefits and Limitation	5-21
5.4.2 Potential Repowering Market	5-22
5.4.3 Repowering Options	5-23
5.4.4 Repowering Configurations	5-23
5.4.5 Line Focus Repowering Analysis	5-27
5.5 INDUSTRIAL PROCESS HEAT	5-35
5.5.1 Objectives and Scope of Current Study	5-38
5.5.2 Industrial Process Heat Market	5-39
5.5.3 Analytical Model	5-39
5.5.4 Analytical Procedures	5-41
5.5.5 IPH Study Results	5-42
6. GROWTH POTENTIAL	6-1
6.1 IMPROVED PERFORMANCE	6-1

CONTENTS (Continued)

	<u>Page</u>
6.2 IMPROVED DESIGN	6-1
6.3 IMPROVED MANUFACTURING/ASSEMBLY	6-3
7. DEVELOPMENT ISSUES	7-1
7.1 INTRODUCTION	7-1
7.2 SOLAR SELECTIVE ABSORPTIVE COATINGS	7-1
7.3 CONCENTRATOR DEVELOPMENT	7-2
7.4 RECEIVER DEVELOPMENT	7-3
7.5 SALT TECHNOLOGY DEVELOPMENT	7-3
8. CONCLUSIONS	8-1
8.1 GENERAL CONCLUSIONS	8-1
8.2 COMPARISON OF CENTRAL RECEIVER AND LINE FOCUS SYSTEMS	8-1
8.3 OUTLOOK FOR APPLICATIONS OF LINE FOCUS SYSTEMS	8-2
8.4 NECESSARY LFS TECHNOLOGY DEVELOPMENTS	8-3
8.5 POTENTIAL AREAS FOR FURTHER WORK	8-3
REFERENCES	R-1
APPENDIX A - LINE FOCUS SOLAR CENTRAL POWER SYSTEM PERFORMANCE SPECIFICATION.	A-1
APPENDIX B - OPTIMIZATION OF SYSTEM OPERATING TEMPERATURES	B-1
APPENDIX C - PRELIMINARY EVALUATION OF THERMAL STORAGE CONCEPTS FOR SALT COOLED LFS CONFIGURATIONS	C-1
APPENDIX D - ANALYSIS OF THE GENERAL ATOMIC FIXED MIRROR SOLAR CONCENTRATOR	D-1
APPENDIX E - EVALUATION OF THE T-2100 PARABOLIC TROUGH COLLECTOR.	E-1

FIGURES

	<u>Page</u>
1-1 Program Overview	1-3
1-2 Line Focus Central Power System Organization	1-4
2-1 1976 Barstow, California Solar Insolation	2-4
2-2 BDM Line Focus Power Plant Schematic	2-5
2-3 BDM Collector Field Plot Plan	2-7
2-4 GA Plant Schematic	2-8
2-5 GA Line Focus Power Plant Plot Plan	2-10
2-6 SRI System Schematic	2-11
2-7 SRI Collector Field Configuration	2-11
2-8 Schematic of System Analysis Process	2-13
2-9 Line Focus Annual Efficiency Staircases	2-14
2-10 BDM Busbar Cost of Electricity vs Annual Average Capacity Factor	2-17
2-11 GA Busbar Cost of Electricity vs Annual Average Capacity Factor	2-18
2-12 SRI Busbar Cost of Electricity vs Annual Average Capacity Factor	2-19
3-1 T-2100 Solar Collector Construction	3-3
3-2 BDM Collector Field Configuration	3-3
3-3 GA Selected Concentrator Design	3-4
3-4 GA Collector Field Arrangement	3-5
3-5 SRI Cement Heliostat	3-5
3-6 SRI Collector Field Configuration	3-6
3-7 Top Level Receiver Characteristics	3-9
3-8 BDM Heat Transport Subsystem Configuration	3-12

FIGURES (Continued)

	<u>Page</u>
3-9 GA Heat Transport Subsystem Configuration	3-12
3-10 SRI Heat Transport Subsystem Configuration	3-13
3-11 BDM Thermal Storage Concept	3-14
3-12 GA Thermal Storage Design	3-16
3-13 SRI Thermal Storage Design	3-16
4-1 Evaluation of Power Plant Design Concepts	4-2
4-2 Performance Normalization Model	4-4
4-3 Normalized Receiver Subsystem Heat Loss, % of Receiver Incident Power at Solar Noon	4-6
4-4 Normalized EPGS Parasitic Power	4-11
4-5 Common Collector - Heliostat Elements	4-13
4-6 Sample Component Cost Estimating Procedure	4-22
4-7 Flow Diagram for Analysis	4-24
4-8 Envelope of Busbar Energy Costs, 100 MWe Turbine: Contractor Data	4-26
4-9 Busbar Energy Cost vs Plant Efficiency and Field-Specific Cost for 100 MWe Turbine, Contractor Data	4-26
4-10 Busbar Energy Cost vs Plant Efficiency and Field Specific Cost, 100 MWe Turbine, Current Technology	4-27
4-11 Busbar Energy Cost vs Plant Efficiency and Field Specific Cost, 100 MWe Turbine (Growth Potential) from Normalized Values	4-27
4-12 Annual Energy Efficiency Staircase Aerospace Normalized BDM Design	4-29
4-13 Annual Energy Efficiency Staircase Aerospace Normalized GA Design	4-29
4-14 Annual Energy Efficiency Staircase Aerospace Normalized SRI Design	4-30
4-15 Annual Energy Efficiency Staircase Aerospace Normalized MM ACR	4-30

FIGURES (Continued)

	<u>Page</u>
4-16 Envelope of Busbar Energy Cost, Aerospace Normalized Designs, BDM Turbine Parametrics	4-31
4-17 Envelope of Busbar Energy Cost, Aerospace Normalized Designs, GA Turbine Parametrics	4-31
4-18 Envelope of Busbar Energy Cost, Aerospace Normalized Designs, SRI Turbine Parametrics	4-32
4-19 Envelope of Busbar Energy Cost, Aerospace Normalized Designs, MM Turbine Parametrics	4-32
4-20 Envelope of Busbar Energy Cost, 100 MWe Turbine, Aerospace Normalized Designs.	4-33
5-1 Potential Line Focus Application.	5-2
5-2 Summary of Potential Solar Markets	5-2
5-3 Heat Input Characteristics of Modern Steam Cycles	5-5
5-4 Industrial Process Heat Temperature Distribution	5-5
5-5 Nominal GA Field Layout; L/W = 1.66, A = $24 \times 10^6 \text{ ft}^2$ (Equinox Noon Conditions).	5-7
5-6 Optimum HTS Pipe Diameters	5-7
5-7 Collector Field Layout Options	5-8
5-8 Segmented Field Design (Equinox Noon Conditions)	5-8
5-9 Percentage Change in Plant Costs vs Field Length to Width Ratio	5-11
5-10 Percentage Change in GA LFSP Capital Costs vs Distance Between Collector Modules	5-11
5-11 Application of High Pressure Nuclear Steam Cycle to Line Focus Technology	5-13
5-12 Energy Cost for "Combined" and Hybrid Plants	5-16
5-13 Annual Energy Efficiency Staircase "Combined Line Focus" Design	5-16
5-14 Modified Steam Cycle	5-17

FIGURES (Continued)

	<u>Page</u>
5-15 Optimized Line Focus Power System	5-17
5-16 Hybrid System Schematics	5-20
5-17 Candidate Fossil Heaters	5-20
5-18 Repowering Options	5-24
5-19 Non-Reheat Plant Repowering	5-25
5-20 Reheat Plant Repowering	5-26
5-21 Economizer Evaporator Repowering	5-26
5-22 Regenerator Repowering	5-28
5-23 Utility System Simulation Model	5-28
5-24 Repowering Cost/Benefit Line Focus vs Central Receiver	5-30
5-25 Schematic of Solar Feedwater Heating Subsystem	5-31
5-26 Solar Feedwater Heating Subsystem Integrated with Conventional Steam Plant	5-34
5-27 Potential Increase in Plant Capacity as a Result of Solar Feedwater Heating	5-36
5-28 Potential Improvement in Fossil Fuel Heat Rate Due to Feedwater Heating	5-36
5-29 Potential Fuel Savings for 100 MWe Plant Using Solar Feedwater Heating	5-37
5-30 Regenerator Repowering with Line Focus Collector	5-37
5-31 Cumulative Distribution of Industrial Process Heat Load	5-40
5-32 Industrial Process Heat Model	5-40
5-33 Collector System Efficiency	5-43
5-34 System Parasitic Losses	5-43
5-35 Annual Plant Efficiency as a Function of Plant Size	5-45

TABLES

	<u>Page</u>
2-1 System Requirements Outline	2-1
2-2 System Performance Requirements	2-2
2-3 Environmental Requirements	2-3
2-4 Required Plant Operating Modes	2-5
2-5 Line Focus Solar Central Power System - Summary	2-8
2-6 Plant Cost Estimate Summary by Account (x \$1000)	2-16
2-7 BDM Design Evaluation	2-20
2-8 GA Design Evaluation	2-21
2-9 SRI Design Evaluation	2-22
3-1 Collector Characteristics	3-2
3-2 Annual Collector Performance	3-2
3-3 Concentration Evaluation	3-6
3-4 Receiver Details	3-8
3-5 Receiver Performance	3-8
3-6 Receiver Evaluation	3-10
3-7 HTS Evaluation	3-13
3-8 Comparison of Thermal Storage Concepts	3-14
3-9 Thermal Storage Evaluation	3-17
3-10 Electrical Power Generating Subsystem Summary	3-17
3-11 EPGS Evaluation	3-18
4-1 Procedures for Normalized Performance Comparison	4-4
4-2 Annual Collector Performance	4-5
4-3 Normalized Heat Transport Thermal Losses	4-8
4-4 Normalized HTS Pumping Powers	4-10

TABLES (Continued)

	<u>Page</u>
4-5 EPGS Auxiliary Power	4-10
4-6 Normalized Cost Breakdown for Heliostat and Collectors (\$/ft ² Aperture)	4-13
4-7 Collector Cost Backup Data	4-14
4-8 Normalized Receiver Cost Breakdown	4-18
4-9 Receiver Cost Background Data	4-18
4-10 Summary of Capital Cost Algorithms Used in Parametric Analysis . . .	4-19
4-11 Summary of Indirect Costs	4-24
5-1 Capital Cost Penalties	5-10
5-2 Repowering Options	5-24
5-3 Reference Assumptions	5-30
5-4 Benefits of Solar Feedwater Heating	5-32
5-5 HTS Design Point Data - 300 MWt (Summer Solstics)	5-41
5-6 Annual Energy Generation - 300 MWt	5-44
5-7 Process Heat Energy Costs - 300 MWt	5-44
5-8 IPH System Design Point Data - 600°F	5-45
5-9 Annual Energy Calculation - 600°F	5-46
5-10 Process Energy Costs - 600°F	5-46
6-1 Solar System Growth Potential.	6-2
6-2 Cost Reductions Due to Improved Design	6-2
6-3 Improved Manufacturing and Assembly Techniques	6-3
7-1 BDM Development Issues	7-1
7-2 SRI Development Issues	7-1
7-3 GA Development Issues	7-2

FOREWORD

The work reported herein was conducted under U.S. Department of Energy Contract No. EY-76-C-03-1101(PA #14) under the overall cognizance of R. Hughey, Director of Solar Energy Division, and under the specific direction of L. Prince, Program Manager, DOE/SAN.

This report was prepared by the Energy Projects Directorate in the Energy and Resources Division of The Aerospace Corporation. Principal contributors to the report were: J.V. Coggi, Energy Projects Directorate, J.H. Albert, Data Concepts and Analysis Department, K. Zondervan, System Test and Evaluation Department, M. Pope, Data Concepts and Analysis Department, and T.J. Connor, Energy Systems Directorate.

SECTION 1

INTRODUCTION

The Department of Energy, through its Division of Solar Technology, is engaged in an effort to develop the technology for the practical and economic conversion of sunlight into electricity. In support of this effort, the Division of Solar Technology has recently conducted a program with three industrial teams for the analysis, conceptual design, and limited testing of three line focus concepts for central utility power generation.

This report summarizes The Aerospace Corporation analysis and evaluation of these line focus designs and technology and compares their potential with that of the central receiver point focus concept. The report is in two volumes: Volume I is an executive summary and Volume II contains the system evaluation and the Appendices.

Volume II is organized in eight sections and five appendices. Section 1 is the introduction and summary. Section 2 describes, compares and evaluates the overall system designs. Section 3 performs the same function on a subsystem basis. Section 4 presents an independent normalized performance and cost evaluation of the three line focus concepts and compares them with the salt central receiver point focus design. Section 5 outlines potential line focus application studies. Section 6 presents the line focus growth potential. Section 7 identifies line focus development issues. The study conclusions and recommendations are given in Section 8.

Due to time limitations, the Aerospace study was based only on data presented by the contractors prior to and including their final reviews and may not reflect their final designs as presented in their final reports.

1.1 PROGRAM OBJECTIVES

The major goal of the program is to assess the applicability of line focus technology for generation of large scale electrical power. The specific objectives of the current program are to:

- Develop the optimum line focus solar central power plant system conceptual design.
- Compare the line focus solar central power plant with the first generation point focus central receiver technology on the basis of cost effectiveness.
- Identify the most attractive utility and commercial line focus application and assess the overall market potential.

To achieve these objectives, DOE via solicitation RFP No. ET-78-R-03-2073 dated July 1978, funded three contractors to perform detailed designs of 100 MWe line focus power systems. The study approach for these three designs is described below.

1.2 STUDY APPROACH

The overall program methodology which served to guide the system analysis, design and evaluation is depicted in Figure 1-1. The program was composed of 10 interrelated tasks:

Task 1 Requirements Definition	Review the DOE requirements definition document and provide comments and recommendations.
Task 2 Parametric Analysis	Evaluate a wide range of subsystem configurations and sizes to obtain preliminary subsystem data on design cost and performance. Subsystem level optimizations are made and system-dependent data are provided to Task 3.
Task 3 Selection of Commercial System Configuration	Perform system level tradeoff studies to select the preferred commercial system configuration based on maximizing the potential worth of the system to the utility.
Task 4 Commercial Plant Conceptual Design	Prepare a conceptual plant design for the concept selected in Task 3.
Task 5 Commercial Plant Cost and Performance Estimates	Prepare preliminary cost and performance estimates for the commercial scale plant conceptual design developed in Task 4.
Task 6 Limited Subsystem and Component Experiments	Design, fabricate, perform, and report on limited experiments.
Task 7 Assessment of Commercial Line Focus Plant	Assess the economics, performance, potential improvements, and limitations of the line focus plant.
Task 8 Development Plan	Deleted during the study. ⁽¹⁾
Task 9 Phase II Plan and Proposal	Deleted during the study. ⁽¹⁾
Task 10 Program Planning and Management	Provide planning, management, and reporting to accomplish the study.

(1) As originally conceived, Phase I of the multi-phase line focus program would just develop conceptual designs and then in later program phases the concept or concepts with the best overall potential would be developed. DOE chose not to continue the study beyond Phase I.

Figure 1-1. Program Overview

1.3 CONTRACTORS AND TECHNICAL MANAGEMENT

The program organization is summarized in Figure 1-2. DOE selected three contractor teams to design 100 MWe systems each using a different line focus approach:

- (a) The BDM Corporation (BDM)
Albuquerque, New Mexico
(Contract No. DE-AC03-78-ET-20524)

Subcontractors:

Stearns-Roger
Solar Kinetics
Public Service of New Mexico

The BDM concept incorporates a parabolic trough collector system to provide heat for a conventional low pressure non-reheat steam cycle. Thermal storage is based on the single tank thermocline system.

Figure 1-2. Line Focus Central Power System Organization

- (b) General Atomic Company (GA)
San Diego, California
(Contract No. DE-AC03-78-ET-20535)

Subcontractors:

Bechtel National, Inc.
Southwestern Public Service Company
Energy Systems Group of Rockwell International Corporation

The GA solar collector is a fixed mirror tracking receiver configuration which heats a draw-salt working fluid to temperatures beyond 1000°F. The salt transfers heat to a conventional high pressure reheat steam cycle. Thermal storage uses the two tank principle.

- (c) SRI International
Menlo Park, California
(Contract No. DE-AC03-78-ET-20530)

Subcontractors:

Bechtel National, Inc.
Foster Wheeler Development Corporation
Acurex/Aerotherm Corporation
Pacific Gas & Electric Company
University of Illinois

The SRI system consists of multiple rows of linear heliostats which reflect solar energy to a line receiver situated on a 200 ft tall tower bridge structure. The steam plant utilized a modern high pressure reheat steam cycle. Thermal storage is a modified two tank configuration.

- (d) FMC Corporation
San Jose, California
(Contract No. DE-AC03-76-ET20426)

The concluding phase of an existing linear heliostat test program was also included within the scope of this program. These test results were principally applied to the SRI configuration.

The Aerospace Corporation served as the DOE technical manager for the program. Aerospace assisted DOE in program planning, provided technical guidance, reviewed progress and approved technical results of the line focus contractors. Aerospace also performed independent technical analysis of contractor concepts, and performed comparative evaluation of the line focus concepts with competing point focus designs. The last two elements are the basis of this report.

Sandia Laboratory, Livermore, provided DOE/SAN with an independent evaluation and review of this line focus project.

1.4 SUMMARY

An evaluation was completed to ascertain the applicability of line focus technologies to electrical power applications and to compare their performance and cost potential with point focus central receiver power systems. It was concluded that although the high temperature line focus (SRI) and fixed mirror line focus (GA) concepts duplicate the heat source characteristics and power conversion technology of the central receiver concepts these configurations do not offer a sufficient improvement in cost to warrant full scale development. The systems are, however, less complex than their point focus counterpart and should the central receiver system development falter they provide reasonable technology alternatives.

The parabolic trough concept (BDM) was found to provide a low temperature technology alternative to the central receiver concept with promising performance and cost potential. Its continued development is recommended, with special emphasis on lower temperature (< 700°F) applications.

Finally, a variety of new promising line focus power system configurations were identified for a range of utility and industrial applications and recommendations were made on their implementation.

SECTION 2

SYSTEM DESCRIPTION

This section gives a brief system level description and comparison of the contractor Line Focus Power System designs. Also included is an evaluation of the strengths and weaknesses of the three designs. Detailed system descriptions are available in the contractor final reports (References 1 to 3).

2.1 SYSTEM REQUIREMENTS

The preliminary system requirements and guidelines were specified by DOE at the outset of the program in the Requirements Definition Document. The contents of this document are outlined in Table 2-1, and the document is provided in its entirety in Appendix A.

Table 2-1
SYSTEM REQUIREMENTS OUTLINE

- SYSTEM/SUBSYSTEM DESCRIPTION AND INTERFACES
- CODES AND STANDARDS
- SYSTEM DESIGN REQUIREMENTS
 - Electrical Power Output
 - Operating Modes
 - Subsystem Requirements
- ENVIRONMENTAL CONDITIONS
 - Design Environments
 - Operating Environments
 - Survival Environments
- LFPP COST BREAKDOWN STRUCTURE

The Requirements Definition provides a detailed description of the system, subsystems, and all applicable interfaces. The document also provides delineation of the Codes and Standards or references to specific documents, which will govern the ultimate design of the Line Focus Power Plant (LFPP).

The performance requirements are summarized in Table 2-2. The key design requirement which sizes the plant is a power level of 100 MWe, to be available at

least four hours on winter solstice, without use of thermal storage and assuming normal insolation. Although this design point was specified for comparative evaluation purposes, the contractors were allowed to vary the plant rating and energy storage capacity if more attractive economic performance resulted.

Table 2-2
SYSTEM PERFORMANCE REQUIREMENTS

<u>ATTRIBUTE</u>	<u>REQUIREMENT</u>
Design Power Level	100 MWe net
Min Power Level from Storage	70 MWe net
Thermal Storage Rating	420 MWe-hr net
System Startup Times	Hot Start - 20 min Cold Start - 6 hr
Plant Availability	0.9, excluding insolation outage
Energy Output	820 MWe-hr/day/minimum
System Output Voltage and Frequency	Compatible with SCE Barstow grid
Lifetime	30 yr with maintenance
Reference Site	Barstow, California

The plant environmental requirements are noted in Table 2-3. The reference site for the power plant is Barstow, California. The insolation curves which were used to describe the direct normal insolation at Barstow are shown in Figure 2-1. These curves peak at about 980 W/m^2 at solar noon almost every day of the year. A solar availability of 0.9, representing 35 cloudy days per year, was used throughout.

Other key requirements specified in the document are plant operating modes. The seven specified operating modes are defined in Table 2-4.

2.2 PLANT DESIGN DESCRIPTION

2.2.1 BDM Plant Description

A schematic diagram for the BDM LFPP is shown in Figure 2-2. The plant satisfies the design requirement for a nominal output of 100 MWe for four continuous hours

Table 2-3
ENVIRONMENTAL REQUIREMENTS

<u>ATTRIBUTE</u>	<u>REQUIREMENT</u>
<u>Solar Insolation</u>	1976 Barstow insolation levels (see Figure 2-1)
<u>Temperature</u>	
Design Point Operation	Wet bulk, 23°C (74°F) Dry bulk, 28°C (82.6°F)
Operating Range	-30°C to +50°C (-23°F to +121°F)
Survival	-30°C to +60°C (-23°F to 140°F)
<u>Wind Conditions</u>	
(At 10 m Elevation)	
Design	3.5 m/sec (8 mph)
Wind Velocity Profile	Varies exponentially with the 0.15 power of height
Max Survival	40 m/sec (90 mph)
<u>Seismological</u>	UCB 1976 Edition, Section 2312 Seismic Zone 3 NRC Reg. Guide 1.60 response spectrum 75% damping Base accelerations of 0.3 g and 0.2 g
<u>Soil Conditions</u>	Barstow data
<u>Lightning Protection</u>	Cost-risk basis Loss of single heliostat/concen- trator acceptable

Table 2-3
ENVIRONMENTAL REQUIREMENTS (Continued)

<u>ATTRIBUTE</u>	<u>REQUIREMENT</u>	
<u>Precipitation</u>		
Rain		
Average Annual	750 mm (30 in.)	
Max 24 hr Rate	75 mm (3 in.)	
Snow (Design Snow Load)	240 pa (5 psf)	
Sleet (Max Ice Buildup)	12.5 mm (1/2 in.)	
Hail	<u>Any Orientation</u>	<u>Stowed</u>
Diameter	20 mm (3/4 in.)	25 mm (1 in.)
Specific Gravity	0.9	0.9
Terminal Velocity	20 m/s (65 fps)	23 m/s (75 fps)

Figure 2-1. 1976 Barstow, California Solar Insolation

Table 2-4
REQUIRED PLANT OPERATING MODES

- CS-RTS driving the EPGS (ESS is not involved)
- CS-RTS driving the EPGS and charging the ESS (normal solar power operation)
- CS-RTS driving the EPGS while the ESS also discharges to share in driving the EPGS (low solar power operation)
- CS-RTS charging the ESS and ESS discharging to drive the EPGS (intermittent cloudiness)
- CS-RTS charges ESS only (thermal storage charging)
- ESS discharges to drive the EPGS (extended operation)
- Overnight shutdown and hold of all plant subsystems (subsystem conditioning)

Abbreviations

CS - Collector Subsystem
 EPGS - Electrical Power Generating Subsystem
 ESS - Energy Storage Subsystem
 RTS - Receiver Subsystem

Figure 2-2, BDM Line Focus Power Plant Schematic

and approximately 230 MWe from thermal storage. BDM selected a low pressure 165 MWe turbine, with 150 MWe net output for power conversion. This choice was based on a tradeoff between conversion efficiency and the cost of routing solar energy indirectly through storage or directly through the turbine. A resultant capacity factor of 0.41 (based on a rating of 150 MWe) places the solar LFPP in the intermediate plant category.

The collector layout consists of two fields totalling 12.68 million ft². About 85 percent of the field operates at low temperatures (~592°F) and uses Monsanto's Therminol 55, and the remaining portion operates at high temperatures (~740°F) and uses Dow-Corning's Syltherm 800 inorganic coolant. The objective of the dual field is to minimize the quantity of high-cost Syltherm. In operation, the low temperature field provides energy to the boiler, preheaters and low temperature storage, hence setting the turbine throttle pressure; while the high temperature field provides energy to the superheater and high temperature storage, thus setting throttle temperature. Figure 2-3 shows the system plot plan. The separation of the plant into quadrants and a highly modular design of high and low temperature subfields were selected to decrease inventory, increase reliability, and to ease control and operations and maintenance (O&M) requirements.

Storage is implemented using the thermocline principle with a dual medium configuration. For low temperature storage T-55 and taconite are used and for high temperature storage Syltherm and taconite are used.

The collector subsystem uses the T-2100, 21 ft aperture linear parabolic trough arrayed in 604 1000 ft rows spaced about 50 feet apart with north-south axis orientation.

A summary of the BDM system characteristics is given in Table 2-5.

2.2.2 GA Plant Description

The conceptual design of the GA LFPP is illustrated schematically in Figure 2-4. The plant contains a solar collector field which heats draw salt from 557°F to 1075°F. The molten salt is then transported either to a thermal storage system of 420 MWe-hr capacity or to a salt-to-steam generator. Steam is generated at 2400 psi and 1000°F and passed through a single reheat turbine.

Significant system level parameters for the plant are given in Table 2-5. The collector field utilizes GA's fixed mirror solar concentrator (FMSC), which consists of a cylindrical array of fixed mirror strips mounted so that their foci vary over a circular area throughout the day, and a simple lightweight movable heat receiver which tracks the focus. The collector field contains 10.4 million ft² of mirror surface arranged into 972 rows, each 900 ft long, spaced 25 ft apart.

The receiver is a heat receiver tube to which is clamped a removable nickel-clad copper foot with a selectively absorptive coating (Pt-Al₂O₃ cermet). The receiver is insulated on the back with calcium silicate and has a borosilicate glass window. It has a shallow secondary concentrator which is integrated into the thin steel sheet casing of the receiver shell.

Figure 2-3. BDM Collector Field Plot Plan

Table 2-5
LINE FOCUS SOLAR CENTRAL POWER SYSTEM - SUMMARY

<u>SYSTEM</u>	<u>SRI</u>	<u>GA</u>	<u>BD44</u>
Plant Rating (MWe)	100	100	130
Thermal Storage Size (MWe-hr)	750	420	230
Average Daily Capacity Factor (M.D.)	0.6	0.5	0.4 (based on 140 MWe turbine)
Average Annual Efficiency (%)	16.9	12.9	11.9
<u>COLLECTOR SUBSYSTEM</u>			
Concentrator Type	One Axis Heliostat	Fixed Mirror	Parabolic Trough
Unit Area (ft ²)	1600	199 (11.8 x 16)	420 (20 x 21)
Collector Aperture Area (ft ²)	9.8×10^6	10.4×10^6	12.6×10^6
<u>RECEIVER SUBSYSTEM</u>			
Receiver Configuration	Linear Cavity on Tower; Internal Heat Absorbing Tube	Cavity, Steel Shell w/Tube Trussing	"T" Tube with glass cover
Receiver Module Dimensions	6 ft dia - 4 ft aperture x 30 ft length	1-3/4 ft absorber tube dia 5.3 x 5.2 x 36 ft	4.3 ft dia tube, 140 mm dia pyrex glass cover
Number of Receiver Rows	10	972	604
Receiver Length/Row (ft)	4420	900	1000
Coolant Inlet/Outlet Temp (°F)	450/1050	561/1069	432/592 LT Field 557/700 HT Field
<u>ENERGY STORAGE SUBSYSTEM</u>			
Storage Media	Draw Salt	Draw Salt	T35/Taconite LT Field Syntherm 800/Taconite HT Field
Storage Configuration	Modified two-tank	Two tank	Thermocline
Storage Temperatures (°F/°F)	450/1050	561/1050	432/592 LT Field 557/700 HT Field
<u>ELECTRICAL POWER GENERATING SUBSYSTEM</u>			
Turbine Inlet conditions (psi/°F/°F)	2400/1000/1000	2400/1000/1000	413 psi/700°F
Net Heat Rate (Btu/kW _e -hr)	8615	8600	11173 at 165 MWe 11899 at 100 MWe

Figure 2-4. GA Plant Schematic

The collector field is sized to simultaneously generate a net power of 100 MWe and fill the energy storage system of 420 MWe-hr capacity on the day of maximum heat collection, March 21. This permits the plant to operate directly from insolation at 100 MWe net for approximately 4.5 hr on the day of worst heat collection, December 21. The resulting capacity factor of the plant, based on year-round clear-day insolation levels at Barstow, California, is 0.456.

Energy is collected in the receiver and transported through the field piping using molten draw salt as the fluid medium. The field piping is arranged (see Figure 2-5) to minimize the expensive 316 stainless steel hot piping runs. Less expensive carbon steel is used on the warm legs.

The energy storage subsystem (ESS) is decentralized to minimize piping costs. The ESS contains two hot tanks, each 61 ft in diameter by 36 ft high, and two warm tanks, 58 ft in diameter by 35 ft high. Salt is pumped from the hot tank to the centrally located steam generator. Feedwater is supplied to the preheater at 2627 psig and 450°F, and steam leaves the superheater at 2400 psig and 1000°F.

The steam turbine is a commercially available tandem-compound unit operating at 3600 rpm and rated at 106.2 MWe gross. At maximum guaranteed load, the throttle steam conditions are 2400 psig/1000°F and reheat steam conditions 421 psig/1000°F. The steam power conversion cycle achieves a turbine gross heat rate of 8072 Btu/kW-hr, i.e., a gross electrical power generating subsystem (EPGS) efficiency of 42.3 percent. The net EPGS efficiency (accounting for station auxiliary loads) is 39.6 percent.

2.2.3 SRI Plant Description

A schematic drawing of the SRI system is shown in Figure 2-6. The sun's radiation is reflected from second-surface mirror panels mounted on the heliostat frame and is directed to the receiver aperture. The single axis concentrators are each 10 ft wide and 160 ft long and are controlled by a central computer. Each heliostat is aimed by a single motor and all heliostats move in synchronism.

The receiver is a horizontal cylindrical cavity 6 ft in diameter with a 4 ft aperture. Located at the top of a 200 ft tower truss structure, the aperture faces downward to the north at an angle of about 40° to the horizontal. The top edge of the aperture has doors, the reflective inside surface of which acts as a secondary concentrator, and which close at night to conserve heat. The inside of the cavity is lined with horizontal heat exchanger tubes backed by fiber insulation. The heat absorber tubes are arranged to take advantage of once-through, multipass, counterflow heating of molten draw salt by locating the incoming tubes near the aperture, with the final pass in the center where the flux density is the greatest. The hot salt is delivered through insulated downcomers and an insulated common horizontal pipe directly to storage tanks and to the heat exchanger that generates steam for the turbine/generator. The function of the ESS is to buffer the EPGS from excessive variations in insolation, and to extend the plant's generating capabilities into periods of low (or no) insolation.

Figure 2-5. GA Line Focus Power Plant Plot Plan

COLLECTOR/RECEIVER	STORAGE	EPGS
MOLTEN SALT $T_{IN} = 550^{\circ}\text{F}$, $T_{OUT} = 1050^{\circ}\text{F}$ COLLECTOR AREA: $9.8 \times 10^6 \text{ m}^2$ CAPACITY FACTOR: 0.60	MOLTEN SALT TWO TANK 550/1050 $^{\circ}\text{F}$ 750 MW _e -hr	GE STEAM TURBINE, 100 MW 2400 psi/1000 $^{\circ}\text{F}$ /1000 $^{\circ}\text{F}$ HEAT RATE 8618 Btu/kW _e -hr

Figure 2-6. SRI System Schematic

Figure 2-7. SRI Collector Field Configuration

The EPGS uses commercial reheat steam cycle technology. The steam throttle conditions are 2400 psig/1000°F and the reheat conditions are 421 psig/1000°F. The turbine gross heat rate is 8072 Btu/kW-hr, i.e., a gross EPGS efficiency of 42.3 percent.

Figure 2-7 shows the SRI plot plan. Table 2-5 indicates the baseline design characteristics for the baseline 100 MWe system.

2.3 SYSTEM PERFORMANCE AND COST

This section describes the techniques and ground rules used by the contractors to develop plant efficiency and costs.

2.3.1 Outline of Calculation

The three contractors used similar system level analytical procedures to calculate their plant annual energy costs. These procedures are outlined in Figure 2-8. The analysis is designed to calculate the system efficiency and specific cost as a function of a series of independent system variables and as a function of variation in the sun position throughout the day and year. Some of the system variables are listed in the figure. In the subsystem level calculation, subsystem tradeoffs which can be optimized without full system participation are determined.

The analysis begins by reading the normal solar incident energy on the reflector from the Barstow data tapes. The incident energy on the receiver is then calculated using the sun-position-variant optical efficiency. The receiver output is calculated by subtracting receiver radiation and convective losses from receiver input energy. The magnitude of this thermal loss is essentially constant throughout the day since both the receiver aperture area and receiver temperature are kept constant. Depending on the operating mode the receiver power is directed either to the EPGS or to storage.

The overall system efficiency is then calculated using the heat-transport and storage thermal losses and the EPGS and receiver conversion efficiency relations. The power output is integrated to determine the energy output for the day and the calculation is repeated for each day of the year to determine the annual energy output. Finally, the system specific costs (i.e., cost per unit of electrical energy output) are calculated using the component capital cost models and economic analysis.

The calculation is repeated until a record of specific cost is available as a function of each of the system independent variables. Then, depending on the system selection criteria, which may include operational constraints, reliability, development risk, growth potential, specific cost factors, and market potential, a system design point selection is made.

2.3.2 Performance Comparison

The staircase efficiencies for the three line focus plants are shown in Figure 2-9. The figure represents contractor data and no effort has been made to critique or normalize the data.

Figure 2-8. Schematic of System Analysis Process

Figure 2-9. Line Focus Annual Efficiency Staircases

The BDM year round efficiency for the plant is calculated at 14.4 percent, and plant output is 5.38×10^6 kWe-hr with a solar availability of 90 percent. This corresponds to a 40 percent capacity factor based on a turbine rating of 150 MWe. GA's annual efficiency is 12.9 percent and the plant output is 4.26×10^6 kWe-hr. This corresponds to a 45.6 percent capacity factor. The SRI efficiency is 14.9 percent and the annual output is 5.26×10^6 kWe-hr. Their plant capacity factor is 60 percent.

Each of these values is based on different subsystem performance assumptions and various plant operation strategies. In Section 4 the performances of the plants are compared using similar performance and operating strategy assumptions.

2.3.3 Capital Cost Comparison

The capital cost estimates were based on the conceptual design and engineering information prepared in the study in the form of engineering drawings, outline specifications, and equipment lists. The construction cost estimate is composed of field costs, engineering services, contingency and fee. The largest category, field costs, contains the direct costs of permanent plant equipment and labor; and the indirect costs of temporary construction materials, supervision, etc., which are to be distributed across the facilities. The estimates anticipate direct-hire operation employing field construction labor forces.

All estimates use second quarter 1979 price and wage levels. No allowance has been made for future escalation.

Field Costs

Field costs include the plant equipment, subcontracts for installation of equipment, materials, and construction labor.

Indirect Field Costs

The indirect field costs are those items of construction costs that cannot be directly attributed to the permanent plant facilities and thus are accounted separately.

The items covered by indirect field costs are:

- Temporary Construction Facilities: Temporary buildings, working areas, parking areas, utility system and general purpose scaffolding.
- Construction Service Supplies, and Expenses: General job cleanup, maintenance of construction equipment and tools, material handling and surveying, construction equipment, small tools, consumable supplies and purchased utilities.
- Field Staff, Subsistence and Expense: Field craft supervision, engineering, procurement, scheduling, personal warehousing, first aid and the cost of operating the field office.
- Craft Benefits, Payroll Burdens and Insurances: Associated with the hiring of personnel are certain payroll additives. These include health and welfare, pension, vacation, FICA, workman's compensation taxes, and an allowance to cover subsistence and insurance.
- Equipment Rental: An allowance to cover the rental of construction equipment such as cranes, earth moving equipment, trucks, etc.

Engineering Services

Engineering services include engineering and other home office supports. Engineering includes preliminary engineering and optimization studies, material and subcontract specifications, detailed engineering, vendor drawing review, site investigation, and support to vendors. Other home offices costs are procurement, cost engineering, planning and scheduling of quality assurance, pre-operational testing, and project management.

Contingency

Included in the estimate is a contingency allowance for costs that, while undefined at the time of the estimate, are always incurred during the course of a project and are within project scope. Historical information shows

contingency to range from as low as 10 percent for well developed construction technologies such as power plants and refineries, to 25 percent or more for new and relatively undeveloped construction technologies.

Fee

Prime contractor fees typical for a project of this magnitude and nature have been included.

Plant Capital Costs

A capital cost summary of contractor data is included in Table 2-6 in accordance with the DOE-specified format.

Table 2-6
PLANT COST ESTIMATE SUMMARY BY ACCOUNT (x \$1000)
(Contractor Data)

<u>ACCOUNT NO/DESCRIPTION</u>		<u>BOH</u>	<u>GA⁽¹⁾</u>	<u>SRI</u>
3100	Land, Site Preparation	3,430	4,380	4,720
3200	Administration Areas	1,129	830	802
3300	Concentrator Subsystem	62,280	82,705	11,787
3400	Receiver Subsystem	8,800	31,015	12,331
3500	Master Control Subsystem	2,908	406	400
3600	Heat Transport Subsystem	30,039	26,428	36,985
3700	Thermal Storage Subsystem	9,914	4,631	7,467
3800	EPGS	35,234	24,635	22,857
Total Direct Field Costs		153,774	199,050	101,429
Indirect Field Costs		7,176	28,712	37,225
Total Field Costs		160,950	227,762	138,654
Engineering & Home Office Costs		3,363	11,390	6,934
Total Field & Home Office Costs		164,313	239,152	145,588
Contingency		1,812	34,061	20,100
Fee		—	10,245	6,216
Total Construction Cost		166,125	283,458	171,904
Coolant Costs		—	3,564	7,376
Total Cost		166,125	287,022	179,280
Cost per kWe ⁽²⁾		1,661	2,870	1,793

(1) First Plant Cost Estimate.

(2) This number is based only on engine rating, not on plant energy output and, therefore, is not a good indicator of plant energy costs.

2.3.4 Contractor Busbar Energy Cost (BBEC) Summary

The contractors prepared busbar energy costs for the nominal 100 MWe plant as a function of turbine size and storage capacity. Each contractor converted plant costs to BBEC using the methodology and data base supplied by DOE and described in the RFP.

Figure 2-10 shows the resultant BBEC data for the BDM configuration. The solid curves are for equal collector field size and three turbine sizes (100 MW, 125 MW and 150 MW). The capacity factor is taken with respect to the nameplate rating of the turbine on the basis of an 8760 hour year. Availability of the plant during sunlight hours is 90 percent. The capacity factors on the curves were varied for a fixed turbine size by increasing the thermal energy storage. For a fixed turbine, additional storage does indeed pay for itself through increased amortization of the plant during non-sunlight hours up to a certain amount. After the BBEC minimum adding storage is uneconomical because the fixed size field is unable to provide adequate energy to utilize fully the capacity through the year, and the cost curve

Figure 2-10. BDM Busbar Cost of Electricity vs Annual Average Capacity Factor

risks very rapidly. The results show that for a 700°F, 415 psia steam condition, a dual stage 100 MWe LFPP will provide minimum cost electrical energy with a 150 MWe turbine generator and 230 MWe of storage.

For the GA design, (Figure 2-11), the BBEC declines as the capacity factor is increased. The capacity factor can be increased by enlarging the size of the collector field and the thermal storage system. BBEC declines to 143 mills/kW-hr at an 83 percent capacity factor. The reduction of BBEC occurs because the fixed cost portions of the plant, such as the EPGS and buildings, are amortized over a larger yearly electric output.

As the plant rating is increased, the GA BBEC declines, as shown in Figure 2-11. The reasons for the initial BBEC reduction are (1) that the EPGS efficiency increases modestly with plant rating, (2) the costs of some portions of the plant (such as software, some buildings, and the salt charging system) do not change, and (3) other portions of the plant, such as EPGS components, scale less than linearly with plant rating. Collector field costs scale almost directly with plant rating, but

Figure 2-11. GA Busbar Cost of Electricity vs Annual Average Capacity Factor

the heat transport system cost scales nonlinearly with plant rating, since the piping not only increases as the collector field increases but experiences disproportionately greater thermal losses and salt pumping power. As a consequence, the BBEC initially declines with increasing plant rating but then shows a decreasing advantage with increasing plant capacity factor. In the case of a 500 MWe plant, the minimum occurs at about a 55 percent capacity factor.

GA's calculations have been based on first plant cost estimates. While GA believes that some improvements in costs will occur as the plant is replicated, its report did not contain BBEC data for the Nth plant.

The SRI BBEC data, shown in Figure 2-12, is based on Nth plant cost estimates. The BBEC drops with capacity factor for reasons similar to those of GA. In its analyses SRI used learning curves for only the receiver, heliostats, HTS and thermal storage subsystems to generate Nth plant costs.

Figure 2-12. SRI Busbar Cost of Electricity vs Annual Average Capacity Factor

The BDM approach to conceptual design was to propose a low temperature, low risk configuration with the use of current state-of-the-art technology, and then to identify areas where advanced materials and/or technology could enhance the overall performance of the plant. Strengths and weaknesses of this design are summarized in Table 2-7.

Table 2-7
BDM DESIGN EVALUATION

<u>STRENGTH</u>	<u>WEAKNESS</u>
1. Near state-of-the-art technology	1. Two stage design adds complexity
2. Modular design for reliability, low cost, application	2. Poor material storage effectiveness due to low ΔT
3. Coolant does not freeze	3. Multiple ESS and steam generator design adds complexity
4. Long rows reduce HTS costs and improve collector efficiency	4. Poor EPGS efficiency
5. Collector based on effective T-700 design	5. HTS/ESS design layout may not be optimum
6. Low temperature yields lower development risk	6. Potential safety problems with oil
7. Capacity factor matches large intermediate market	7. Thermocline storage needs further study
8. Easy to conduct scaled experiments	
9. Scales well to other plant sizes	
10. Materials compatibility better known	

The BDM T-2100 solar collector used in the study is an extension of the smaller, successful T-700 design modified to improve efficiency and reduce cost. This unit should have little development problems and has the potential to be a major solar collector in the 1980s. The effectiveness of the receiver assembly, however, depends on the successful development of a stabilized black chrome coating.

The key drawback to BDM's design is the requirement for a dual field because of temperature limitations on lower priced, technically advanced fluids. This results in

a highly segmented design for the collector field, heat transport subsystem, thermal storage and steam generators. Thermal storage is less effective because two different thermocline types are required, with attendant low temperature differentials across storage. Finally, because of pressure limitations, the efficiency of the steam cycle is poor.

The GA design strengths and weaknesses are given in Table 2-8. The GA design utilizes the fixed mirror tracking receiver design whose development has already begun under Sandia Albuquerque sponsorship. GA developed a well integrated design which optimizes the overall configuration of the collector field, heat transport subsystem and thermal storage tanks. The solar subsystems provide energy to the EPGS at sufficiently high temperatures to utilize the most modern conventional steam cycle technology. A major drawback is the lack of development of the salt technology in terms of component development, containment, and operations.

Table 2-8
GA DESIGN EVALUATION

<u>STRENGTH</u>	<u>WEAKNESS</u>
1. Good plant performance	1. Fixed reflector surfaces exposed to environmental hazards
2. Good collector field, HTS and GSS design optimization	2. Cement collector cannot be built in factory
3. Output can be matched to utility annual load profile	3. Daily drain and fill of receiver is an operational complexity
4. Modern steam plant conditions	4. Salt fluid technology requires development
5. Modular design reduces development costs	5. Operational problem with intensive salt inventory over extended field area
6. Scales to other plant sizes	6. Key components such as receiver with water and pumps require development
7. High volumetric energy density in storage	7. Containment problems with salt

GA has yet to demonstrate the effective collection of radiative energy by the reflector unit. Problems with energy scatter associated with the prototype collector unit have been identified and the solutions have been proposed.

This receiver also utilizes an advanced low emissivity coating whose development is not complete. The design is sufficiently versatile, however, so that the combination of stabilized black chrome coating at low temperature and the Pyromark coating at the higher temperature provides adequate performance.

The SRI design is an adaptation of the point focus heliostat design. The contractor expects the cost of the linear heliostats will be low enough to offset the cost of the large receiver and thereby become competitive with the central receiver concept. The key SRI strengths and weaknesses are listed in Table 2-9.

The key problem is the receiver. Its effectiveness is dependent on the availability of low emissivity second surface coatings. These coatings are not yet developed nor has major emphasis been placed on their development. The large surface area of this receiver also creates the potential for high convective heat losses. If air velocities inside the receiver cavity are a significant percentage of external velocities, a large percentage of the absorbed heat will be lost to the environment by convection. Additional tests must be performed to identify the magnitude of this loss before the value of the plant is clearly demonstrated.

Table 2-9
SRI DESIGN EVALUATION

<u>STRENGTH</u>	<u>WEAKNESS</u>
1. Modern steam turbine conditions	1. Design based on availability of second surface coating
2. Modular design reduces development cost	2. Receiver convective losses unknown
3. Expected low O&M costs	3. Three tank thermal storage may not be cost effective
4. Large linear collector reduces cost	4. Salt inventory throughout field creates operational problems
5. Salt ESS allows wide range of capacity factors	5. Salt fluid technology requires development
6. High volumetric storage energy	6. Development of key components
7. Modular design allows broad range of plant sizes	7. Salt containment uncertainties

SECTION 3

SUBSYSTEM DESCRIPTION

This section gives a brief description and comparison of the Line Focus Subsystem designs, including an evaluation of their strengths and weaknesses. Detailed descriptions of the subsystems are available in the contractor final reports.

3.1 COLLECTOR SUBSYSTEMS

The collector subsystem consists of the equipment required to focus the incident sunlight into the receiver aperture. A summary of key contractor collector design characteristics is outlined in Table 3-1. The collector efficiencies are noted in Table 3-2.

3.1.1 BDM Collector Subsystem

The BDM concentrator subsystem consists of an array of linear parabolic troughs which focus sunlight onto a receiver tube assembly located at the linear focus of the trough. The collector system consists of all attached apparatus, excluding the receiver tube subassembly, and includes mounting, tracking, control and power equipment. The collector subsystem will track in one axis with a focus which is fixed with respect to the trough aperture geometry.

The BDM Line Focus Power Plant (LFPP) collector is the T-2100, single axis tracking, linear parabolic trough oriented in a north-south direction. The tracking system developed by Solar Kinetics is hydraulically actuated. The T-2100 collector shown in Figure 3-1 is a 20 ft long 21 ft aperture trough with three reflector sections field assembled on concrete pylons. A total of 10 troughs are included in a single tracking row. The BDM field configuration and key characteristics are shown in Figure 3-2. Within the LFPP design a total of five tracking rows are connected in series to complete one LFPP collector row, providing a nominal 21,000 ft² of collector area. A total of 604 of these 1000 ft rows, contained in both the low and high temperature collector fields, constitute the entire concentrator array.

3.1.2 GA Collector Subsystem

The GA concentrator subsystem reflects and focuses incident insolation onto a moving heat receiver. The subsystem consists of the FMSC primary concentrator panel, its support, and foundations.

The GA collector design is shown in cross section in Figure 3-3. The main structure of the concentrator is a concrete shell with a nominal thickness of 4.6 in. The inner radius of the shell is about 96 in. and the aperture is 142 in. wide. The concentrator shell contains 71 facets on its inner surface, each of which is 2 in. wide.

Table 3-1
COLLECTOR CHARACTERISTICS

	BDM	GA	SRI
Aperture Area (ft ²)	400	213	1600
Packing Factor (Mirror/Land Area)	0.31	0.02	0.02
Module Width (ft)	22	11.833	10
Module Length (ft)	30	18	160
Operating Reflectivity	0.96	0.93	0.9
Optical Error Budget (m rad)*	4.9	4.6	3.3
Stow Angle	Inverted	N.A.	Inverted, tilted 7° to horizon
Collector Spacing (ft)	30.0	23	18.0
Rotational Axis Height (ft)	13	N.A.	6
System Weight (lb/ft ²)	6.6	82.21	13.1
Installed Capital Cost (\$/ft ²)**	3.69	6.85	3.85
Installed Capital Cost (\$/lb)	0.83	0.08	0.38
Annual Operating & Maintenance Cost (%)	1.5	1.0	1.0

* Includes panel slope error, panel deflection, specularity, structural deflection, drive deflection, foundation deflection.

**All field cost but land including all elements within interfaces. Includes fee plus contingency.

Table 3-2
ANNUAL COLLECTOR PERFORMANCE

<u>Optics Parameters</u>	<u>2-Axis HelioStat</u>	<u>BDM Parabolic Trough</u>	<u>GA Fixed Mirror</u>	<u>SRI Linear HelioStat</u>
Cosine Factor	0.766	0.831	0.666	0.70
Collector Blocking/Shading	0.96	0.913	0.967	0.996
Receiver Shading	0.998	1.0	0.963	0.986
Edge Losses	1.0	1.0	0.91	1.0
Atmospheric Attenuation	0.91	1.0	1.0	0.986
Receiver Intercept/End Loss	0.96	0.98	0.9	0.889
Secondary Concentrator	1.0	1.0	0.972	1.0
Overall Optical Efficiency	0.979	0.685	0.465	0.563

Figure 3-1. T-2100 Solar Collector Construction

SIZE AND NOMENCLATURE:

FIELD DIMENSIONS	: 6550 x 6300 ft
APERTURE AREA	: $12.6 \times 10^6 \text{ ft}^2$
MODULE	: 6 QUADRANTS EACH SELF CONTAINED
SUBARRAY PER MODULE	: 2 LOW TEMPERATURE 3150 x 1100 ft
	: 1 HIGH TEMPERATURE ARRAY 2250 x 1100 ft
ROWS PER SUBARRAY	: HIGH TEMPERATURE ARRAY - 46/50 x 1000 ft
(no dimensions)	: LOW TEMPERATURE ARRAY - 64/50 x 1000 ft
COLLECTORS PER ROW	: 50

NUMBER OF COMPONENTS

NUMBER OF COLLECTORS	: 30,200
NUMBER OF DRIVE MOTORS	: 3,020
NUMBER OF CONTROLLERS	: 604

Figure 3-2. BDM Collector Field Configuration

Figure 3-3. GA Selected Concentrator Design

The GA collector field configuration is shown in Figure 3-4. The parallel rows of concentrators are placed on 25 ft centers. This provides sufficient room for a 12 ft wide roadway between each row for transportation access. All rows are nominally on the same level. A 1:5000 slope is provided along the concentrator row to allow the hot salt to drain from the system, and to allow any water collected on the mirrors to run off.

3.1.3 SRI Collector Subsystem

The SRI heliostat is shown in Figure 3-5. The heliostat contains four modules 10 ft wide and 40 ft long; each module made up of four 10 ft² reflector panels. Four modules totaling 1600 ft² of aperture are connected on a common rotational axis 6 ft above the ground and driven with a single drive mechanism located between the second and third modules. The heliostats are supported on cast-in-place concrete caissons with 6 ft pedestals. The collector field layout (Figure 3-6) consists of 16 receiver rows each serviced by 21 rows of collectors.

3.1.4 Collector Subsystem Evaluations

A summary of top level strengths and weaknesses of the collector subsystems is given in Table 3-3. Detailed Aerospace evaluations of the collector designs were provided to DOE in References 4 to 6. The results of Aerospace review of the optical performance of the GA and BDM collectors are contained in Appendices D and E. The SRI optical analysis was spot checked and then correlated to the FMC experimental results (Reference 7) and found to provide an excellent representation of the optical physics.

SIZE AND NOMENCLATURE

FIELD SIZE	: 3910 x 6384 ft
APERTURE AREA	: $10.4 \times 10^6 \text{ ft}^2$
SUBARRAY (no/dimensions)	: 21912.5 x 3062 ft
ROWS PER SUBARRAY	: 488
COLLECTORS PER ROW	: 50
COLLECTOR SIZE	: 11.833 x 18 ft

NUMBER OF COMPONENTS

NUMBER OF COLLECTORS	: 48,800
NUMBER OF DRIVE MOTORS	: 976
NUMBER OF CONTROLLERS	: 976

Figure 3-4. GA Collector Field Arrangement

Figure 3-5. SRI Cement Heliostat

Figure 3-6. SRI Collector Field Configuration

Table 3-3
CONCENTRATION EVALUATION

	<u>BDM</u>	<u>CA</u>	<u>SRI</u>
STRENGTHS	<ul style="list-style-type: none"> • Best performance • Possibly lowest cost • Near state-of-the-art design • Modular design • Large aperture area per drive • Hydraulic drive system provides excellent control 	<ul style="list-style-type: none"> • Fixed collector • Cheap structural materials 	<ul style="list-style-type: none"> • Good performance • Promising RGC technology • Module design
WEAKNESSES	<ul style="list-style-type: none"> • Concept temperature limited • Glass reflective surface requires development • Performance at off sun angles needs verification 	<ul style="list-style-type: none"> • Cannot be factory assembled • Assembly of multiple glass strips • Angular tolerances and flat edge prevent glass support must be reduced • Possible vulnerability to hail damage • Edge seal problems 	<ul style="list-style-type: none"> • Less than desirable receiver intercept factor • RGC structure is a development item

3.2 RECEIVER SUBSYSTEM

The receiver subsystem transfers the incident solar heat to the plant working fluid for distribution to the steam generators and thermal storage. The three receiver designs are shown in Figure 3-7. A summary of receiver details is given in Table 3-4 and the receiver performances are summarized in Table 3-5.

3.2.1 BDM Receiver Subsystem

The BDM receiver tube subassembly (Figure 3-7) is a linear apparatus located at the focal region of the trough. It consists of a carbon steel tubing on which is affixed a black chrome exterior coating. The coolant fluids are continually passed through the respective low and high temperature receiver tubes. A glass annulus encapsulates the entire tube assembly to reduce thermal losses.

The receiver tubes are field assembled after the concentrator subsystem has been installed. The receiver tube sections are installed and coupled together, with the receiver tube stand and the collector subsystem used as the supporting structure. At the end of each row the receiver tube is coupled through a flexible hosing to the heat transport subsystem.

3.2.2 GA Receiver Subsystem

The GA receiver subsystem consists of the heat receiver and truss, the receiver support system, the receiver aiming system, the receiver positioning mechanism, and the receiver instrumentation system. A cross section is shown in Figure 3-7.

The heat receiver tube in this design is 1.5 in. in outside diameter and 0.049 in. thick and extends the full 900-foot length of the receiver row. The tube material is carbon steel in the lower temperature ($<800^{\circ}\text{F}$) sections and type 316 stainless steel in the remaining higher temperature sections.

3.2.3 SRI Receiver Subsystem

The SRI receiver modules are supported by towers at an altitude of 200 ft. Each module consists of the tube bundle, support structure, and insulation. The tube bundle contains 112 tubes, 0.75 in. O.D. by 0.049 in. wall, of which 84 are carbon steel and 28 are stainless steel. Each module has two circuits of 16 panels each. The lower circuit has three tubes per panel and the upper circuit has four tubes per panel.

The receiver tower design is a self supporting steel structure, 200 ft high. The design is based on the ASCD Manual 52 for electric transmission towers. The towers are constructed on the ground from galvanized steel sections. Once assembled, they are raised and placed on their foundations by a high lift crane.

3.2.4 Receiver Subsystem Evaluation

A top level summary of receiver strength and weaknesses is shown in Table 3-6. Detailed Aerospace evaluations were provided to DOE in References 4 to 6.

Table 3-4
RECEIVER DETAILS

	<u>RCM</u>	<u>GA</u>	<u>SR1</u>
Receiver Dimensions	3.1 in O.D. x 20 ft	4.7 in x 36 ft	6 ft dia x 28 ft
Receiver Duct Dia/Thick (in./in.)	4.3/0.093	1.3/0.045	.73/0.045
Duct Material	CS	CS 800°F, 316/800°F	CS 800°F, 316/800°F
Selective Surface Coating	Black Chrome	Pt - Al ₂ O ₃	SiC - SiC
Absorptivity at Temperature	0.96	0.94	0.90
Emissivity at Temperature	0.15	0.30	0.86
Cover Glass Thickness (in.)	0.094	0.10	N.A.
Cover Glass Solar Transmissivity	0.99	0.98	N.A.
Insulation Material	dry air	Calcium Silicate	Fiberglas
Insulation Thickness (in.)	0.213	1.8	4 to 9
Peak Temperature (°F)	770	1097	1140
Fluid Velocity (ft/sec)	1	1.5	2.69
Heat Transfer Coefficient (Btu/hr-ft ² -°F)	300	385	311

Table 3-5
RECEIVER PERFORMANCE

	(Annual Averages)		
<u>LOSS PARAMETERS</u>	<u>RCM</u>	<u>GA</u>	<u>SR1</u>
Transmissivity	0.91	0.91	1.0
Absorption	0.93	0.94	0.998*
Convection	0.84	0.83	0.835
Radiation	0.94	0.94	0.905
Overall Receiver Efficiency	0.713	0.662	0.725

*Includes cavity effect

	BDM	GA	SRI

TYPE	TUBE WITH PYREX COVER	CAVITY WITH SEC REFLECTOR	CAVITY ON TOWER
CONSTRUCTION	FIXED TUBE	STEEL SKIN WITH TUBULAR TRUSSING	CURTAIN WALL, TUBE TO TUBE WELDED
FLOW CONTROL	TEMPERATURE CONTROL VALVES	VARIABLE SPEED PUMPS AND TC VALVES	CHANGE IN NUMBER OF PUMPS PLUS TC VALVES
TUBE EXPANSION ACCOMMODATION	ALLOWED TO GROW	ALLOWED TO GROW	ALLOWED TO GROW
INLET/OUTLET TEMP (°F)	LOW TEMP: 437/589 HIGH TEMP: 531/740	50/1050	950/1050
PEAK POWER RATING (MW _t)	564	550	697
SPECIFIC WEIGHT (lb/ft)	5.1	22	350
SPECIFIC COST (\$/ft)	5.9	60	1300

Figure 3-7. Top Level Receiver Characteristics

Table 3-6
RECEIVER EVALUATION

	<u>BDM</u>	<u>GA</u>	<u>SRE</u>
STRENGTHS	<ul style="list-style-type: none"> • Modular design • Factory construction • Simple concept • Little support structure required 	<ul style="list-style-type: none"> • Best performance receiver • Modular design • Factory assembly 	<ul style="list-style-type: none"> • Modular design • Factory assembled • No apparent fatigue problems
CONCERNS	<ul style="list-style-type: none"> • Lack of operating experience on black chrome coating • Low Reynolds number • Flow turndown and control • Flex hose leakage problems • Syntharm 800 operating experience • Advantages of D shape tube not demonstrated 	<ul style="list-style-type: none"> • Requires advanced selective surface coating • Flow turndown and control • Daily startup • Salt freezing problems • Seismic stability • Secondary concentrator need verification • Tube thermal expansion 	<ul style="list-style-type: none"> • Requires advanced selective surface coating • Field flow in the transition region • Massive structural towers required • Low average flux on tubes • Convective cooling loss needs verification by test

3.3 HEAT TRANSPORT SUBSYSTEM

The heat transport subsystem (HTS) is used to convey thermal energy from the receivers to the steam generator or to the thermal storage hot tanks, when insolation exceeds electrical power generating subsystem (EPGS) requirements. The HTS also conveys thermal energy from the thermal storage tanks to the steam generator, to implement the receiver when the insolation falls short of the EPGS requirements.

3.3.1 BDM Heat Transport Subsystem

The BDM HTS is designed to transfer sufficient thermal energy to the EPGS to produce a gross electrical generation power of 165 MWe during noon of summer solstice as well as to generate 100 MWe net at noon winter solstice. The field layout is divided into low temperature and high temperature fields. The pumping system is designed to provide sufficient flow to limit the collector field maximum temperature of 592°F for the low temperature field and to 740°F at maximum insolation conditions for the high temperature field. Additional pumping capacity is provided for the makeup pumps and the small storage pumps.

The BDM collector field configuration can be represented in four quadrants or modules for the low temperature field and two halves or modules for the high temperature field. The four quadrants of the low temperature field are made up of mirror image quadrants with two submodules per quadrant for a total of eight submodules.

Each of the modules is served by an independent supply and return pumped HTS loop. A schematic representation of these loops is shown in Figure 3-8.

3.3.2 GA Heat Transport Subsystem

The GA HTS configuration is shown in Figure 3-9. The primary features of the GA HTS are the sharing of stainless steel hot manifolds by adjacent receiver tiers, decentralized location of hot and warm salt storage tanks at the base of each hot manifold, location of the salt pumps in the field near the tanks, and the provision of an optional oil fired salt heater for plant operation during prolonged periods of cloudy weather.

3.3.3 SRI Heat Transport Subsystem

The SRI HTS configuration is shown in Figure 3-10. SRI used a main carbon steel cold manifold down the length of the field to distribute fluid to each of the 16 tower submanifolds. These manifolds distributed the salt to the receiver modules. The return lines which parallel the supply lines are made of stainless steel.

3.3.4 Heat Transport Subsystem Evaluation

Top level comments on the contractor HTS designs are given in Table 3-7. Detailed evaluations of these designs were included in References 4 to 6.

3.4 ENERGY STORAGE SUBSYSTEM

The energy storage subsystem (ESS) is used to store the thermal energy from the receiver subsystem when this energy is not used directly for electric power generation. The stored energy is delivered to the EPGS during cloudy periods or at night. A summary of line focus contractor ESS characteristics is shown in Table 3-8.

3.4.1 BDM Energy Storage Subsystem

The BDM energy storage subsystem uses sensible energy storage with the thermocline principle in vertical cylindrical tanks. A schematic of the subsystem is shown in Figure 3-11. The major components of the ESS are tanks, the energy storage media, the fluid pumps and the ullage or vapor maintenance system.

The ESS is designed to provide sufficient thermal storage to generate a total of 230 MWh of electrical energy. The materials contained in the ESS tanks for sensible storage are dual media heat transfer fluid plus taconite. The taconite in each tank is stationary and the fluid is transported in or out through either the top or the bottom distribution manifold. The storage fluid for the low temperature ESS tanks is Therminol 55 while the fluid for the high temperature field ESS tanks is Syltherm 800.

Figure 3-8. BDM Heat Transport Subsystem Configuration

Figure 3-9. GA Heat Transport Subsystem Configuration

COOLANT:	SALT
PIPING MATERIALS:	CARBON STEEL
COLD PIPE (< 800°F)	316 SS
HOT PIPE (> 800°F)	7.5×10^6 lb/hr
PEAK FLOW RATE:	647 psi
PRESSURE DROP:	8.1 MW _g
PEAK PUMPING POWER:	8.5 MW _t
PIPING HEAT LOSSES:	

Figure 3-10. SRI Heat Transport Subsystem Configuration

Table 3-7
HTS EVALUATION

	<u>BDM</u>	<u>GA</u>	<u>SRI</u>
STRENGTHS	<ul style="list-style-type: none"> • All carbon steel design • Oil operating experience • Conservative piping design 	<ul style="list-style-type: none"> • Best integrated field layout • Reviewed salt operating experience at temperatures greater than 1000°F 	<ul style="list-style-type: none"> • Conventional design • Optimized layout
WEAKNESSES	<ul style="list-style-type: none"> • Multiple loops are costly • High parasitic losses • Synthrom 800 is costly • Multiple steam generator not proven cost effective 	<ul style="list-style-type: none"> • Salt freezing problems • Salt heat exchangers not operated at temperature conditions • Salt leakage may be problem • Requires heat tracings • High temperature pumps are a development item 	<ul style="list-style-type: none"> • Salt freezing problems • Salt heat exchangers not operated at temperature conditions • Salt leakage may be problem • Requires heat tracings • High temperature pumps are a development item

Table 3-8
COMPARISON OF THERMAL STORAGE CONCEPTS

	<u>BDM</u>	<u>GA</u>	<u>SRI</u>
TSS Capacity (MWt-hr)	1083	1098	1965
Storage Efficiency	0.90	0.97	0.97
Storage Type	Thermocline	Two tank	Modified Two tank
Storage Media	Low temp TSS/Taconite High temp Syltherm/Taconite	Draw hot	Draw cold
Number of Tanks	6	6	6
Tank Type	Cylindrical API	Cylindrical API	Cylindrical API
Tank Volume (ft ³)	Low temp 5.3×10^5 High temp 0.77×10^5	Warm: 1.9×10^5 Hot: 3.9×10^5	Warm: 1.85×10^5 Hot: 3.6×10^5
Tank Material	CS	CS cold tank SS hot tank	CS tank wall 316 SS liner
Insulation	Not available	Internal, soil External, calcium Sulfate with A-1 Weather protection	Internal, ceramic refractory External, calcium
Base Foundation	Concrete	Pierotic concrete	Pierotic concrete

STORAGE CAPACITY	:	230 MW _g -hr
THERMOCLINE SYSTEM	:	2 HT TANKS, 4 LT TANKS
STORAGE MEDIA	:	COLD LOOP - TSS + & TACONITE
	:	HOT LOOP - SYLTHERM & TACONITE
STORAGE TEMPERATURES	:	COLD LOOP - 452-592°F
	:	HOT LOOP - 557-740°F

Figure 3-11. BDM Thermal Storage Concept

There are four low temperature ESS tanks (one per module) and two high temperature ESS tanks (also one per module). The tanks are located in the center area of the plant near the EPGs.

3.4.2 GA Energy Storage Subsystem

The GA energy storage subsystem, shown schematically in Figure 3-12, contains two warm salt tanks and two hot salt tanks. One warm and one hot tank are located at the center of the western half of the collector/heat receiver field. The remaining warm and hot tanks are at the center of the eastern half of the field. Associated with each pair of tanks is a cover gas system and a salt charging and makeup system. Each tank also has a purification loop with an auxiliary salt heater.

3.4.3 SRI Energy Storage Subsystem

The SRI energy storage subsystem (Figure 3-13) is a modified two tank configuration. A set of three tanks are used for each field. The third tank can be used for both hot and cold fluid storage. During the day, two tanks are filled with hot fluid and during ESS operation the dual tank is drained first and later the tank is used by the EPGs to discharge the used coolant from the dedicated hot tank. The process is reversed during storage charging.

3.4.4 Thermal Storage Subsystem Evaluation

Comments on the thermal storage subsystem are included in Table 3-9. Detailed comments are included in References 4 to 6.

3.5 ELECTRICAL POWER GENERATING SUBSYSTEM

The electrical power generating subsystem (EPGS) converts steam energy into electrical energy. The characteristics of the three EPGs are summarized in Table 3-10.

3.5.1 BDM EPGS

The BDM EPGS design produces 165,000 kW gross electrical output for rated throttle conditions of 415 psia, 700°F and 1.7×10^6 lb/hr of steam. The turbine is a three casing, tandem compound, quadruple flow, non-reheat turbine with a hydrogen cooled generator. The three casings consist of one single flow, high pressure element and two double flow, low pressure elements.

3.5.2 GA EPGS

The GA EPGS delivers a net electrical output of 100 MWe at maximum guaranteed load operating conditions. The turbine is a 3600 rpm tandem compound unit rated at 106.2 MWe gross electrical output. At maximum guaranteed load, the throttle steam conditions are 2400 psig/1000°F and the reheat steam conditions are 377 psig/100°F. The low pressure turbine exhausts to a 3 in. Hg (absolute) condenser backpressure. The high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections supply extraction steam for seven stages of feedwater heating as well as steam for the plant auxiliaries. The turbine has an electro-hydraulic control system and operates with constant throttle pressure over the load range.

Figure 3-12. GA Thermal Storage Design

Figure 3-13. SRI Thermal Storage Design

Table 3-9
THERMAL STORAGE EVALUATION

	<u>BOM</u>	<u>GA</u>	<u>SRI</u>
STRENGTHS	<ul style="list-style-type: none"> • All CS tank 	<ul style="list-style-type: none"> • Effective location of storage tanks • Low cost due to high specific heat, low cost per pound 	<ul style="list-style-type: none"> • Low cost due to high specific heat • Low cost per pound
CONCERNS	<ul style="list-style-type: none"> • Low ΔT leads to high volume requirements • OIL and Syntroleum/Tecelene interactions unknown • Thermocline performance must be verified • Multiple tank design not demonstrated cost effective 	<ul style="list-style-type: none"> • Concept not demonstrated • Storage media processing 	<ul style="list-style-type: none"> • Three tank concept not proven more cost effective than two tank • Concept not demonstrated • Storage media processing

Table 3-10
ELECTRICAL POWER GENERATING SUBSYSTEM SUMMARY

	<u>BOM</u>	<u>GA</u>	<u>SRI</u>
Take Characteristics	165 MWs TC 4F-25 nomineer	107 MWs TC 2F-16.7 reheat	107 MWs TC 2F-16.7 reheat
Steam Conditions (psi/°F/°F)	415/700	2400/1000/1000	2400/1800/1000
Max Heat Rate (Btu/kWh-Ar)	12,189	8,326	8,326
Steam Flow Rate (lb/hr)	1.2x 10 ⁶	492,000	492,000
Turbine Back Pressure (Hg)	2.3	3.0	3.0
Number of Steam Extractions	3	7	7
Shaft Speed (rpm)	3,600	3,600	3,600
Feedwater Temperature (°F)	350	450	450
Condenser Size (ft ²)	240,000	67,800	67,178
Condenser Temperature (°F)	109	116	116
Cooling Tower	Mechanical draft	Mechanical draft	Mechanical draft
Cooling Water In/Out Temperature (°F)	53/63	53/60	54/60
Circulating Water Flow Rate (GPM)	142,000	42,800	42,000

3.5.3 SRI EPGS

The SRI turbine is a 3600 rpm tandem compound unit rated at 107.2 MWe gross electrical output. At maximum guaranteed load, the throttle steam conditions are 2400 psig/1000°F and the reheat steam conditions are 421 psig/1000°F. The low pressure turbine exhausts to a 3 in. Hg (absolute) condenser backpressure. The HP, IP and LP sections supply extraction steam for seven stages of feedwater heating as well as steam for the plant auxiliaries. The turbine has electro-hydraulic controls and operates with constant pressure over the load range.

3.5.4 EPGS Evaluation

Comments on the EPGS system selection are included in Table 3-12. More detailed comments are available in References 4 to 6.

Table 3-11
EPGS EVALUATION

	<u>BDM</u>	<u>GA</u>	<u>SRI</u>
STRENGTHS	<ul style="list-style-type: none">• State-of-the-art energy conversion	<ul style="list-style-type: none">• Good EPGS performance• Available components	<ul style="list-style-type: none">• Good EPGS performance• Available components
CONCERNS	<ul style="list-style-type: none">• High auxiliary loads• Poor cycle efficiency	<ul style="list-style-type: none">• Effect of thermal cycling in turbine life• Salt leakage into cycle• Plant startup at start of day	<ul style="list-style-type: none">• Same as GA

SECTION 4

PERFORMANCE AND COST EVALUATION

INTRODUCTION

The contractor annual energy cost data must be reviewed to insure that the contractors are using similar performance, design, and cost assumptions before judgment can be made as to the relative merits of the various systems. In this section, new contractor annual energy costs are developed based on equivalent performance and cost assumptions. The line focus data are then compared to the advanced central receiver (ACR) technology to determine the relative merits of these two systems for large plant electrical utility applications.

4.1 EVALUATION APPROACH

The systems under evaluation include the line focus parabolic trough (BDM), one axis heliostat (SRI) and the fixed mirror concept (GA). These systems are compared to the Martin Marietta (MM) salt technology central receiver system, considered to be one of the most promising ACR concept.

The system evaluation approach is shown in Figure 4-1. The contractor designs were based on a common set of requirements; however, each concept was also based on different levels of uncertainty in design practices and performance and cost assumptions. The first step in the evaluation or rating of the candidate power systems was the selection of a set of performance attributes. The attributes calculated in detail are busbar energy cost (BBEC), capacity factor, and system efficiency. Other nonquantitative attributes such as development risk and growth potential are discussed in separate sections.

These sets of attributes were first prepared based on the performance and cost data provided by the contractors. Only the top level economic conditions were equalized. The objective of this analysis was to determine the performance and cost goals to bring the systems into competitive range (References 8 to 10).

Because of the nonuniform assumptions used by the contractors, the next step in the analysis was to normalize the contractor performance and cost data. This was done by collecting and apportioning the individual contractor datum into separate performance and cost accounts. Each account was then individually normalized using common assumptions. The data were entered into the computer where the normalized performance attributes were calculated and the individual systems rated.

4.2 COST AND PERFORMANCE NORMALIZATION

In the evaluation of system performance, one can either accept the contractor estimates on the cost and performance of their individual components or, ideally,

Figure 4-1. Evaluation of Power Plant Design Concepts

perform a detailed investigation of the system performance test data, and then analyze all component details and assemble drawings and fabrication processes for cost comparisons. The first approach cannot be used directly since the contractors used inconsistent sets of assumptions. Even the detailed component by component evaluation cannot work at this time since proof of principle has not been reached on most of these concepts and therefore adequate performance data do not exist. Additional difficulties are presented by the differences in design and cost estimating procedures between the two solar communities. The central receiver developers have emphasized the development of ambitious longer term designs and the use of learning curves for estimating costs. The line focus community, in contrast, has concentrated on near term component development and generation of test data rather than placing great emphasis on mass production cost cutting techniques. As a result, the line focus designs were conservative growth versions of existing equipment, perhaps not as sophisticated as their ACR equivalents.

The compromise approach used by Aerospace for cost and performance normalization is summarized below:

- Use contractor data on central receiver performance.
- Use Aerospace modified performance data on line focus.
- Equalize the effects of unresolved issues such as startup problems, O&M, construction schedule, etc.
- Use common cost estimating algorithms for common subsystems.
- For unique subsystems such as collectors and receivers, divide subsystems into common elements such as piping and structure and compare on that basis.

4.2.1 Performance Normalization

To insure an equitable evaluation of systems, the attributes of various solar power plant design concepts were based on common procedures and assumptions as summarized in Table 4-1. Analytical models were developed to normalize the energy losses for each of the contractor power plant subsystems. Figure 4-2 illustrates the system performance model. The normalization of each of the five thermal losses will be discussed using the following format: principal assumptions, power loss model, and results.

4.2.1.1 Collector Subsystem Power Losses

The power losses through the collector subsystem are summarized in Table 4-2. The line focus loss factors were generated by Aerospace and reviewed individually with the appropriate contractors (see Appendices D and E). Central Receiver data were based on MM advanced central receiver studies and Sandia Livermore evaluations (References 11 and 12).

Table 4-1

PROCEDURES FOR NORMALIZED PERFORMANCE COMPARISON

- Used Identical Material Properties (i.e., Equal Glass Reflectivity)
- Collector Performance Modified Based on Aerospace Evaluation
- Receiver Thermal Losses Based on Identical Heat Transfer Correlations
- HTS Thermal Losses Normalized to Ratio of Surface Area and Fluid to Ambient Temperature Drop
- Consistent EPGS Efficiency Variation with Temperature and Pressure
- ESS Thermal Losses Proportional to Tank Temperature and Surface Area
- Collector Field Parasitic Loads Proportional to Pumping Power ($w\Delta p$); EPGS Parasitics Assumed Proportional to Load Requirements
- Common Model Used to Calculate Storage Volume from Electrical Energy Requirement

Figure 4-2. Performance Normalization Model

Table 4-2
ANNUAL COLLECTOR PERFORMANCE

<u>Optical Parameters</u>	<u>2 AXIS Helostat</u>	<u>8DM Parabolic Trough</u>	<u>CA Fixed Mirror</u>	<u>SRJ Linear Helostat</u>
Cosine Factor	0.77	0.85	0.67	0.70
Collector Blocking/Shading	0.96	0.91	0.97	0.996
Receiver Shading	0.998	1.0	0.96	0.99
Edge Losses	1.0	1.0	0.91	1.0
Mirror Reflectivity	0.9	0.9	0.9	0.9
Atmospheric Attenuation	0.91	1.0	1.0	0.99
Receiver Intercept/End Loss	0.98	0.98	0.9	0.89
Secondary Concentrator	1.0	1.0	0.97	1.0
Overall Optical Efficiency	0.579	0.685	0.465	0.543

4.2.1.2 Receiver Subsystem Power Losses

Receiver subsystem power losses are attributable to three sources:

- (1) Glass cover solar transmissivity
- (2) Receiver coating solar absorptivity
- (3) Radiation, conduction and convective heat losses.

When applicable, item (1) was normalized to a value of 91 percent. Item (2) was normalized based on temperature. Systems operating under 750°F were assumed to employ stabilized black chrome coating with an absorptivity of 95 percent. The systems operating at temperatures above 750°F were assumed to employ low emissivity (0.2) selective coating with an absorptivity of 90 percent.

The receiver convective, conduction and radiative thermal losses were assumed constant throughout the day while the receiver was operating at design temperature. Due to the complex nature of the receivers, no attempt was made to normalize the receiver losses in detail. However, one dimensional analyses were made to verify that the heat losses were in the expected range. The receiver losses as a percentage of the incident noon solar flux are given in Figure 4-3.

Figure 4-3. Normalized Receiver Subsystem Heat Loss, % of Receiver Incident Power at Solar Noon

4.2.1.3 Heat Transport Subsystem Losses

Each of the contractors used different procedures to calculate the heat transport loss terms. An HTS heat loss model was therefore developed to calculate consistent values.

The principal assumptions of this analysis were:

- (1) One dimensional planar heat transfer by conduction, convection and radiation
- (2) Calcium silicate used for insulation (consistent with all contractors)
- (3) Wind velocity of 3.5 m/sec
- (4) Ambient temperature of 75°F.

For an HTS operating at uniform temperature, i.e., a supply line or return line, the following total heat loss expression was derived:

$$Q = \pi k (T_f - T_a) \left(\sum_{i=1}^n \frac{D_i L_i}{t_i} \right)$$

where

- Q = heat loss
- n = number of distinct pipe sections
- t = thickness
- k = conductivity
- D = pipe section diameter
- L = pipe section length
- T_f = heat source temperature
- T_a = ambient temperature.

The values of D_i, L_i, t_i and T_f were taken from the contractor final reports. The results of the normalized heat loss calculations are given in Table 4-3 for the baseline designs.

4.2.1.4 Thermal Storage Sizing and Power Losses

The thermal storage model for normalized thermal losses was based on the same assumptions as used for the HTS analysis. The thermal storage normalized power losses for a single ESS tank were given as:

$$Q_{top} = \frac{\pi}{4} k \left(\frac{D^3}{t} \right) (T_f - T_a)$$

$$Q_{side} = \pi k \left(\frac{D^4}{t} \right) (T_f - T_a)$$

where

- Q_{top} = heat loss from top of tank
- Q_{side} = heat loss from side of tank
- k = insulation conductivity
- t = insulation thickness

- D** = tank diameter
H = tank height
T_f = tank fluid temperature
T_a = ambient temperature.

Table 4-3
NORMALIZED HEAT TRANSPORT THERMAL LOSSES

Contractor		T _{HT} °F	T _{LO} °F	k _{HT} Btu/hr, ft., °F	k _{LO} Btu/hr, ft., °F	Σ _{i=1} ^N $\frac{D_i L_i}{U_i}$ HT ft	Σ _{i=1} ^N $\frac{D_i L_i}{U_i}$ LO ft	Q Btu/hr	Q MW
BOM	HT Field	740	531	0.0381	0.0393	22896	41379	1.74 x 10 ⁶	1.10
	LT Field	569	437	0.0367	0.0312	136390	393732	21.0 x 10 ⁶	6.14
	Total	—	—	—	—	—	—	22.7 x 10 ⁶	7.24
GA	RS-ESS	1030	561	0.0430	0.0340	44335	146681	13.7 x 10 ⁶	4.02
	ESS-EPGS	1030	561	0.0430	0.0340	3391	8820	1.23 x 10 ⁶	.36
SR3	RS-ESS	1030	561	0.0430	0.0340	192636	191369	36.5 x 10 ⁶	10.7
	ESS-EPGS	1030	561	0.0430	0.0340	11419	18236	2.52 x 10 ⁶	.66
MM	RS-ESS							12.8 x 10 ⁶	3.75
	ESS-EPGS							0.20 x 10 ⁶	.06

The ESS tank storage volume is sized to provide for:

- EPGS operation from storage
- 24 hr heat loss from tanks (see above)
- Overnight heat loss from generator loop
- Overnight generation of auxiliary steam
- Energy for heat tracing (if required).

The storage volume is then:

$$\text{Volume} = \frac{\text{Input Energy}}{\text{Vol. Heat Capacity} \times \Delta T} + 10\% \text{ (void)}$$

4.2.1.5 Plant Auxiliary Loads

The plant auxiliary loads are the total electrical power required by the plant's auxiliary equipment. The magnitude of the auxiliary loads varies depending on the plant's operating mode.

Collector, Receiver, Thermal Storage Auxiliary Power

The power required by the collector, receiver and thermal storage subsystems is used primarily for control equipment. A review of all four contractors' data showed that these power demands are a relatively small percentage of the total load. The contractor values for these loads were, therefore, accepted in the normalization analysis.

HTS Auxiliary Power

HTS auxiliary power is chiefly due to the power demand of the HTS pumps. The procedures used by the contractors to calculate pump power demand were based on actual pump data. However, since the pump efficiencies represented by these data varied over a wide range, the resulting pump powers reflected an inconsistent set of power demands. A normalized set of maximum HTS pump powers for each of the conceptual designs was obtained by calculating the HTS fluid power at the pump sites using heat balance data and then dividing these quantities by a single value of pump efficiency (70 percent). Table 4-4 summarizes the results.

The final major category of HTS auxiliary power demand is unique to those systems using salt as a working fluid. For these systems power is required in the form of heat tracing during the nighttime hours to prevent salt from solidifying in the piping lines. The amount of heat tracing power required is proportional to the amount of HTS heat loss. (The proportionality constant is the electric to heat conversion efficiency.) Therefore, the normalized values of HTS heat loss were also used as the nighttime heat tracing power demand for the conceptual designs using salt as an energy transport fluid.

As is the case for all plant subsystems, power required for control purposes was small and the contractor values were accepted at face value.

EPGS Parasitic Power

The EPGS parasitic power was normalized based on the assumption that the parasitic power is proportional to EPGS steam generator duty, which is in turn proportional to turbine output divided by the gross EPGS cycle efficiency. A straight line correlation was expected between EPGS parasitic power and the turbine rating divided by the cycle efficiency. This was found to be the case as is

Table 4-4
NORMALIZED HTS PUMPING POWERS

Contractor	Pump Type	Fluid Density, lb/ft ³	Flow Rate, lb/hr	Pressure Change, psi	Fluid* Power, kW	Normalized** Electric Power, kW
BDM	HT Field	43.4	4.38×10^6	98	361	361
	HT ESS	43.4	1.44×10^6	34	62	89
	LT Field	46.1	25.8×10^6	97	2834	4077
	LT ESS	46.1	7.87×10^6	34	313	430
	LT Boiler	42.9	17.13×10^6	27	303	436
GA	Field	118.7	10.3×10^6	161	743	1061
	ESS	109.4	4.7×10^6	118	281	373
SRI	ESS Field	118.7	14.3×10^6	647	4229	6061
	ESS/EPGS	107.4	4.8×10^6	176	437	610
	EPGS Field	118.7	4.8×10^6	488	1021	1520
MM	Tower				6671	9330
	ESS				338	768

* Fluid Power is the product of Flow Rate and Pressure Change divided by Fluid Density.

** Assumes a pump efficiency of 70%.

shown in Figure 4-4. The normalized values for EPGS parasitic power based on this correlation can be determined from Figure 4-4, but are also given in Table 4-5 for convenience and for comparison with nonnormalized values.

Table 4-5
EPGS AUXILIARY POWER

	<u>BDM</u>	<u>GA</u>	<u>SRI</u>	<u>MM</u>
Contractor Parasitics (MW)	7.06	4.02	4.02	4.55
Normalized Parasitics (MW)	7.72	3.71	3.71	3.83
Turbine Rating (MW)	150	100	100	100

Figure 4-4. Normalized EPGS Parasitic Power

4.2.2 Cost Normalization

The capital cost data are organized in accordance with the DOE subsystem cost breakdown structure as outlined in Section 2. The solar power plant's subsystem design concepts are similar with the exception of the receiver and collectors. The cost normalizations for the heat transport, energy storage, master control, and electrical power generation subsystems were based on common designs and therefore the same cost functions were applied to all. The collectors and receivers, however, are unique designs and the normalization is based on investigation of the elements which make up these components.

4.2.2.1 Collector Specific Cost Evaluation

The collector and receiver components were divided into common technology elements and compared at that level. The procedures used for this normalization are outlined below:

- The collector reflective assembly, structure, actuators, controllers and wiring, pedestal and foundations were evaluated on the basis of a common cost per unit weight.

- Drive costs were normalized based on unit power rating.
- Receiver, piping, structure, insulation costs were based on common cost per unit weight.
- Tower costs were taken from contractor data directly.
- Specific weight and drive data ratings were taken from contractors.
- Installation costs were based on a percentage of capital cost.

The collector and heliostat components are made up of similar types of elements such as the glass reflector, supporting structure, pedestals and foundations, motors and linear actuators, power supply and controllers. These elements are illustrated in Figure 4-5 for the heliostat. The basis for the evaluation is to find common parameters within these elements to base the comparison. The collector normalized cost breakdown is summarized in Table 4-6 and the background data used in its development are summarized in Table 4-7.

The first cost element is the mirror surface. The assumption was made that each device utilizes 50 mill glass with the exception of GA. The GA glass remains exposed to the elements and therefore must be thicker (90 mills) to withstand hail impingement. The contractor consensus was that the material, fabrication, and assembly of the mirror surface would cost \$2 per pound. For GA the glass is installed in numerous 2 inch strips and the GA specific cost is correspondingly higher.

The reflector backing weights were taken from the contractor reports and a common \$1.20 per pound was used to estimate cost. Both BDM and GA use the collector structure for the glass backing and therefore are not charged under this account.

The structural costs are based on contractor estimates of structural weight and a common specific cost for steel and concrete. The ACR two axis heliostat structural weight is lower than that of the parabolic trough even though trough wind and static loads are lower. This is a result of the numerous cost optimization and weight minimization processes which the advanced heliostat program has undergone. Parabolic trough designers have typically concentrated on conservative design for near term hardware delivery and their structural specific weights are higher.

The drive costs were assumed proportional to their power rating to the point eighth power. Due to their one axis design, the line focus systems can control larger areas of aperture area per drive. Actuator costs were set proportional to their weight. Line focus controller costs are also lower since there are fewer drives per unit collector area and each collector behaves identically. The pedestal and foundation costs were set proportional to weight. The lower cost for the heliostats again reflects the advanced lower weight heliostat design rather than lower load requirements.

Figure 4-5. Common Collector - Heliostat Elements

Table 4-6
NORMALIZED COST BREAKDOWN FOR HELIOSTAT AND COLLECTORS
(\$/ft² Aperture)

	ACR 2 Axis Heliostat	BDM Parabolic Trough	GA Fixed Reflector	SRI 1 Axis Heliostat
Mirror Surface	1.16	1.16	2.736	1.16
Reflector Backing	3.24	—	—	2.4
Structure	1.08	2.31	3.81	1.027
Drives	1.22	0.0443	0.033	0.079
Actuators	0.85	0.56	0.25	0.28
Control & Wiring	0.72	0.11	0.093	0.384
Pedestal/Foundation	0.75	0.87	0.7485	0.29
Installation (12.5%)	1.128	0.63	0.96	0.70
Total	10.16*	5.68	8.63	6.32

*Does not include inverted stow capability; adding this capability would ensure a 15% cost penalty.

Table 4-7
COLLECTOR COST BACKUP DATA

	ACR 2 Axis Heliostat	BDM Parabolic Trough	GA Fixed Reflector	SRI 1 Axis Heliostat
1. <u>Mirror Surface</u>				
Specific Weight (lb/ft ²) (glass at 5 mills at 140 lbs/ft ³)	0.58	0.58	1.05	0.58
Fab Glass Cost (\$/lb)	2.00	2.00	2.60	2.00
Specific Cost (\$/ft ²)	1.16	1.16	2.73	1.16
2. <u>Reflector Backing</u>				
Specific Weight (lb/ft ²)	2.7	N.A.	N.A.	2.0
Backing Cost (\$/lb)	1.20			1.20
Specific Cost (\$/ft ²)	3.24			2.40
3. <u>Structure</u>				
Specific Weight (Concrete) (lb/ft ²)	—	—	22.14	7.5
Specific Weight (Steel) (lb/ft ²)	2.4	5.13	1.83	—
Concrete Cost (\$/lb)	—	—	0.135	0.135
Steel Cost (\$/lb)	0.45	0.45	0.45	—
Specific Cost (\$/ft ²)	1.08	2.31	3.81	1.03

Table 4-7 (Continued)

	ACR 2 Axis Heliostat	BDM Parabolic Trough	GA Fixed Reflector	SRI 1 Axis Heliostat
4. <u>Drives (Motors)</u>				
Collector Area/Drive (ft^2)	264	50,000	10,650	1,600
Collector Area/Actuator (ft^2)	264	4,200	409.6	1,600
Motor Rating (HP)	0.25	5.0	0.5	0.125
<u>Baseline Drive</u>				
Cost/Rating				
\$Drive ₀ (0.25 HP) = 210	217	2,245	372.6	126.4
\$Drive = \$Drive ₀ $\frac{\text{HP}}{\text{HP}_0} \times 0.8$		Use hydraulic drive \$2,282		
Drive Specific Cost (\$/ ft^2)	1.22	0.0445	0.035	0.079
5. <u>Actuators</u>				
Collector Area/Actuator (ft^2)	264	4,200	409.6	1,600
Actuator (wt/ ft^2)	0.85	0.56	0.25	0.28
Cost (\$/lb)	1.0	1.0	1.0	1.0
Actuator Specific Cost (\$/ ft^2)	0.85	0.56	0.25	0.28

Table 4-7 (Continued)

	ACR 2 Axis Heliostat	BDM Parabolic Trough	GA Fixed Reflector	SRI 1 Axis Heliostat
6. <u>Controls & Wiring</u>				
Type	HAC	Photocells	Photocells	HAC
Aperture Area/Controller (m^2)	16,890	4,202	3,550	44,030
Specific Cost (\$/ft ²)	0.72	0.11	0.093	0.384
7. <u>Pedestal & Foundation</u>				
Specific Wt (Conc.) (lb/ft ²)	7.57	4.21	6.674	2.9
Specific Wt (Steel) (lb/ft ²)	—	1.04	0.18	—
Cost Concrete (\$/lb)	0.10	0.10	0.10	0.10
Cost Steel (\$/lb)	0.43	0.43	0.43	0.43
Specific Cost (\$/ft ²)	0.731	0.87	0.7485	0.29
8. <u>Installation (%)</u>	12.5	12.5	12.5	12.5

4.2.2.2 Receiver Specific Cost Evaluation

For cost estimating purposes, the receiver was divided into five elements: collector tubes or receiver fluid containment, structure, insulation, glass tube and fasteners and towers. The receiver specific cost summary is given in Table 4-8 and the background data from which it was derived are summarized in Table 4-9.

The receiver surface area for the central receiver plant is considerably smaller than that of line focus due to a higher solar concentration factor. This results in lower receiver weight. However, since the resultant higher temperatures demand more exotic materials, the specific cost is higher. For BDM the solar flux is one-third that of the central receiver; however, the containment material is the cheaper carbon steel.

The receiver structural costs were set proportional to weight. Again the line focus receivers were probably unnecessarily penalized in this regard since they can be mass produced in a factory whereas the central receiver structure is a one-of-a-kind device fabricated on site at the top of a tower.

The receiver tower costs were taken directly from the contractors. The SRI towers are 200 ft tall but can be assembled using ground based equipment, using assembly techniques developed for transmission towers.

4.2.2.3 Cost Normalization Approach for Remaining Solar Plant Subsystems

The remaining plant subsystems utilize similar components, design and technology and, therefore, the cost normalizing was performed on a higher level subsystem basis. These common subsystems are the heat transport, energy storage, master control, electrical power generating plant, land and buildings.

The cost normalization approach is summarized below:

- Organize capital costs by DOE subsystem cost breakdown structure.
- Summarize contractor cost data by account.
- Select subsystem or component cost independent variables.
- Plot contractor cost data against independent variables.
- Fit data to curve and develop analytical expression.

An example of this procedure is shown in Figure 4-6. The contractor heat rejection cost is plotted against the selected independent variable, in this case the heat rejection duty in MWt. A curve was fitted through the data and then an analytical expression was developed to describe that curve. It is this expression that is utilized in the computer program to generate system level parametric analyses. The analytical expressions for subsystem capital costs are summarized in Table 4-10.

Table 4-8
NORMALIZED RECEIVER COST BREAKDOWN

	General Receiver	BOM	GA	SR1
Absorber Unit & Headers *	0.306	0.22	0.36	1.75
Glass Cover & Fastening	—	0.173	—	—
Structure	0.307	0.149	0.843	1.3122
Insulation	0.022	—	0.5	0.423
Tower & Foundation	0.792	—	—	1.41
Crane	0.13	—	—	—
Total	1.394	0.342	1.485	4.895

Table 4-9
RECEIVER COST BACKGROUND DATA

	(ACR) MM	BOM	GA	SR1
Collector Tubes				
Receiver Area (ft^2)	50,000	226,308	159,090	422,033
Surface Flux (Btu/ft^2)	16.83	0.213	3.4	0.971
Tube Length/MTB (ft/MTB)	118	498	1,482	
Tube Material	Insulux 900	C.S.	SS(30%) CS(70%)	SS(60%) CS(40%)
Specific Weight (lb/ft^2)	0.036	0.23	0.0677	0.35
Cost (\$/lb)	9.0	0.87	3.00	3.00
Specific Cost (\$/ft ²)	0.306	0.22	0.36	1.75
Structure				
Wt/ft^2 (lb/ft^2)	0.2273	0.11	0.426	0.9072
Structure Cost (\$/lb)	1.33	1.35	1.35	1.35
Specific Cost (\$/ft ²)	0.307	0.149	0.843	1.3122
Insulation				
Insulation Weight (lb/ft^2)	0.0889	—	0.2	0.169
Cost (\$/lb)	2.3		2.5	2.3
Specific Cost (\$/ft ²)	0.022		0.5	0.423
Glass Pyrex Tube & Fastener				
Glass Weight (lb/ft^2)	—	0.0667 lb/ft^2	—	—
Specific Cost (\$/ft ²)	—	0.173/ft ²	—	—
Tower				
SL Tower Model	0.792			1.41
Crane	0.018			

Table 4-10
SUMMARY OF CAPITAL COST ALGORITHMS
USED IN PARAMETRIC ANALYSIS

3000 Plant Capital Cost

5100 Land and General Site Preparation

5110 Land

$$\$LAND = ACRES \times 700 \left(\frac{ACRES}{1000} \right)^{-0.25}$$

5120 Site Preparation

$$\$SITE = ACRES \times 3000 \left(\frac{ACRES}{1000} \right)^{-0.3}$$

5200 Administrative Areas

$$\$ADMIN = 1,170,000 + 0.77 (GPL) (ACRES)$$

5300 Collector Cost

See Section 4.2.2

5400 Receiver Cost

See Section 4.2.2

5500 Master Control Subsystem

$$\$MSC = A \left[\frac{(GPL)(ACRES)}{69000} \right]^{0.8}$$

where:

$$A = 480,000 \text{ (Line Focus)}$$

$$A = 700,000 \text{ (Point Focus)}$$

5600 Nonsolar Energy Subsystem

5700 Energy Storage Subsystem

5710 Tank Foundations and Berms

$$\$TF \text{ BERMS} = 1.4 VTANK$$

5720 Tanks

HOT TANKS $> 800^{\circ}F$

$$\$T \text{ HOT} = 132 VTANK^{0.8}$$

WARM TANKS $< 800^{\circ}F$

$$\$T \text{ WARM} = 47 VTANK^{0.8}$$

Table 4-10 (Continued)

5730 Circulation Equipment

SALT

$$\text{\$CIRC} = 1460 \text{ VTANK}^{0.4}$$

OIL

$$\text{\$CIRC} = 510 \text{ VTANK}^{0.4}$$

5740 Media

$$\text{SALT} = \$0.15/\text{lb}$$

$$\text{TSS} = \$1.0/\text{gal}$$

$$\text{TACONITE} = \$50/\text{ton}$$

5800 Electrical Power Generating Subsystem

5810 Turbine Building

$$\text{\$TURBBLD} = A \ 1,303,000 + 3780 \text{ (GPL)}$$

where:

$$A = 1.0 \text{ (salt)}$$

$$A = 0.35 \text{ (oil)}$$

5820 Turbine Generator

$$\text{\$TG} = B \ 3,900,000 + \text{GPL}$$

where

$$B = 1.0 \text{ (salt)}$$

$$B = 0.6 \text{ (oil)}$$

5830 Heat Rejection Subsystem

$$\text{\$HRS} = 13,000 \text{ QR}$$

when QR 150

$$\text{\$HRS} = 21470 \text{ QR} - 1,450,000$$

when QR 150

and

$$\text{QR} = \text{GPL} \frac{1}{\text{CYCLE}} + 1$$

5840 Condensing Subsystem

$$\text{\$CON} = 38,000 + 3700 \text{ QR}$$

5850 Feedwater Subsystem

$$\text{\$FW} = 80,000 + 1.83 \text{ QHTR} + 2 \times 10^{-4} \text{ W P}$$

Table 4-10 (Continued)

5860 Working Fluid Circ & Treatment

$$\text{\$ WFT} = 460,000 + 2800 \text{ GPL}$$

5870 Auxiliary Systems

$$\text{\$ AUX} = 4,800,000 + 750 \text{ (GPL)}$$

5880 Electrical

$$\text{SELEC} = 31875 \text{ (GPL)}$$

5900 Heat Transport Subsystem

5910 Field Piping and Valves

See Figure 5-6

5930 Pumps

$$\text{\$ PUMPS} = 330,000 (\text{W}\Delta\text{P})^{0.5}$$

5950 Steam Generators

$$\begin{aligned} \text{\$ SG} = & \left(\frac{\text{PT}}{2400} \right) \left[0.24 \left(\frac{\text{Q}}{\Delta\text{TM}} \right)^{0.65} + 0.55 \left(\frac{\text{Q}}{\Delta\text{TM}} \right)^{0.65}_{\text{B}} \right. \\ & \left. + 0.29 \left(\frac{\text{Q}}{\Delta\text{TM}} \right)^{0.65}_{\text{SH}} + 0.377 \left(\frac{\text{Q}}{\Delta\text{TM}} \right)^{0.65}_{\text{RH}} \right] \end{aligned}$$

the four bracketed terms refer to preheater, boiler, superheater, reheater

NOMENCLATURE

ACRES	=	acres
GPL	=	Turbine gross power level (MWe)
VTANK	=	Tank volume (ft^3)
QR	=	Heat rejected (MWt)
CYCLE	=	EPGS gross cycle efficiency (N.D.)
WΔP	=	Pumping power (MWe)
PT	=	Steam pressure (psia)
Q	=	Heat exchanger duty (Btu/hr)
ΔTM	=	Log mean temperature difference ($^{\circ}\text{F}$)

Figure 4-6. Sample Component Cost Estimating Procedure

4.2.2.4 Cost Normalization Summary and Other Cost Considerations

The scope of this analysis, was limited to capital costs, but other cost factors exist which are dependent on system design. These cost factors include indirects, development costs, O&M, shipping, and length of construction schedule.

For the collector cost analysis most of the fundamental collector characteristics affecting costs favor the line focus systems (LFS). These factors include:

- Fewer types and smaller wind and static loads on LFS structures
- Inherent structural stability by multiple supports
- Much fewer drives, actuators, power supplies, and controllers per unit aperture area
- Modularity
- Smaller loads on foundations due to lighter deadweight, smaller wind loads and multiple supports.

In the receiver the lower surface area requirement on the central receiver system supports lower costs; however, this analysis did not account for what is more likely higher fabrication costs for this type due to unit construction and assembly in the field.

Other cost considerations are treated as cost equals even though fundamentals would generally favor LFS. These cost elements include:

- Installation costs are simpler due to field linearity, simpler components, lower weight, and construction at ground level.
- O&M costs for LFS are lower due to fewer pieces of equipment in field, linear arrays, lower operating temperature.
- Development costs should be lower for the parabolic trough LFS due to the use of nearer term technology, use of less exotic coolants, lower temperatures, and lower heat fluxes.
- LFS collector field power supply costs are less due to fewer number of transformers in field and lower parasitic loads.
- Shipping costs favor LFS due to lower weight.

In addition, the line focus technology has not reached the level of design sophistication as practiced by the central receiver community. Current line focus collectors are designed for early production and test and not optimized for light weight or for mass production. In these studies only a small percentage of the contract cost was able to be budgeted for collector studies, but significant cost improvements were identified. More extensive studies with extensive field volumes in mind will certainly identify cheaper collector and field designs.

A summary of Indirect Costs used in this study is given in Table 4-11. These costs include indirects, contingency and fee.

4.3 BUSBAR ENERGY COST COMPARISONS

The energy cost calculation was performed using an Aerospace developed program for annual energy and cost evaluation. The flow diagram for the computer program is shown in Figure 4-7. The analysis is designed to calculate the annual electrical energy generation including the effects of variation in the sun position throughout the day and the year. The analysis is based on Barstow, California, insolation data. For simpler parametric runs, power generation characterizations are based on three days of the year: summer and winter solstice and spring equinox. The calculated energy generation for the three days is then extended to other days in proportion to the known daily insolation levels throughout the year.

The calculation is performed for the rated power of the plant and the collector field glass area is varied from 0.75 to 2.0 million m^2 . Excess glass area is used to increase energy storage and therefore plant capacity. The plant subsystem performance models used to convert insolation into electrical power to the utility grid are based on the models identified earlier.

Table 4-11
SUMMARY OF INDIRECT COSTS
 (percent)

<u>Account No.</u>	<u>Indirects</u>	<u>Contingency</u>	<u>Fee</u>
5100 Land & Site	10	10	8
5200 Admin Areas	10	10	8
5300 Collectors	15	10	8
5400 Receiver	15	10	8
5500 MCS	25	15	8
5700 Energy Storage	15	10	8
5800 EPGS	15	10	8

Figure 4-7. Flow Diagram for Analysis

The analysis begins by calculating the power converted into steam by the HTS, accounting for the collector field and receiver thermal losses. The thermal energy absorbed in the steam is then converted into electrical energy using the following technique: when the power absorbed by the receiver in transforming water into steam is equal to or greater than power corresponding to the level required for the turbine generator set to provide rated power net to the utility grid, this power is delivered to the turbine; any absorbed power above the rated value is diverted to the thermal storage subsystem for subsequent production of electrical power to the utility grid; absorbed power below rated is also used to charge the thermal storage subsystems.

The electrical energy generated through the day and the year is integrated to yield the total annual energy generation and the plant capacity factor. The plant capital and operating costs are based on the economic models described earlier. The indirect and operations and maintenance costs are assumed proportional to capital costs. The performance and cost models are then combined to yield the plant operating costs for the range of conditions of interest.

4.3.1 First Order Busbar Energy Cost Comparison

The initial busbar energy cost comparison was based on the use of contractor values for the key system independent variables. The busbar energy cost was first calculated parametrically as a function of annual system efficiency and specific capital cost (\$/ft² aperture) for the collector, receiver and heat transport subsystem. These are the subsystems that are particularly unique to the solar plant design in question. Other key economic variables were kept constant including:

- Cost model for land, buildings, EPGS, MCS, and thermal storage
- Economic model
- Indirects, cost contingency and profit percentage.

The busbar costs as a function of the independent variables are shown in Figures 4-8 and 4-9 for capacity factors of 0.4 to 0.6. The contractor values are superimposed on the matrix.

As expected, the central receiver system has higher efficiency than the line focus designs. The central receiver also claims lower specific cost than GA and SRI thereby giving it a substantial busbar energy cost advantage. Only BDM claims a lower specific cost than does the central receiver contractor and this provides BDM with essentially equal busbar costs at the lower capacity factor and a less favorable value at the higher capacity factor.

Production costs are currently available, based on limited production quantities, for both the central receiver and parabolic trough technologies. These costs are superimposed on the busbar matrix in Figure 4-10. The central receiver performance and cost are representative of the 10 MWe Pilot Plant water-steam receiver technology and the parabolic trough data are based on manufacturer's delivered cost to a number of operating trough systems.

Figure 4-8. Envelope of Busbar Energy Costs, 100 MWe Turbine, Contractor Data

Figure 4-9. Busbar Energy Cost vs Plant Efficiency and Field-Specific Cost, 100 MWe Turbine, Contractor Data

Figure 4-10. Busbar Energy Cost vs Plant Efficiency and Field Specific Cost, 100 MWe Turbine, Current Technology

Figure 4-11. Busbar Energy Cost vs Plant Efficiency and Field Specific Cost, 100 MWe Turbine (Growth Potential) from Normalized Values

Another performance comparison can be made on the basis of the maximum growth potential for each of the systems. Growth is measured from the normalized values as developed in Section 4.5.2. Potential performance growth and cost improvements for these systems are discussed in detail in Chapter 6. The results of this comparison, shown in Figure 4-11, indicate that only the parabolic trough line focus technology can challenge the central receiver for central plant electrical utility applications, even under the most favorable conditions for each design.

To become strong contenders for electrical utility applications, the key requirement for line focus plants to demonstrate is for high annual conversion efficiency (>15 percent). This efficiency is composed primarily of annual collector/receiver efficiency and EPGS efficiency. If line focus annual collector/receiver efficiency of 50 percent or greater can be achieved, then, considering that gross EPGS efficiency greater than 35 percent has been routinely achieved with steam conditions of 550°F and 1000 psi, the LFS including the lower temperature parabolic trough, could achieve the required performance and given their capital cost potential, could become competitive in large scale generation of electricity.

4.3.2 Busbar Energy Cost Comparison Using Normalized Line Focus Data

The next set of computer runs was made using the normalized performance and cost data for the line focus subsystems. The performance data needed for the ACR were taken from contractor reports.

The breakdown of the plant annual average efficiencies is given in Figures 4-12 to 4-15 for the individual contractor baseline design case. In evaluating the overall efficiencies of the plant, consideration was given to all potential loss mechanisms. Each of these loss mechanisms has been discussed in detail in previous chapters.

The busbar energy costs as a function of capacity factor are given in Figures 4-16 to 4-19. Three values of turbine rating were used and in all cases the costs were lower with an increased turbine size. Increases in turbine rating beyond 300 MWe were not attempted since these cases may be beyond the capability of the computer model.

Figure 4-20 shows a comparison of the busbar energy costs at the 100 MWe power level. The BDM conventional design remains lower in cost than the ACR to capacity factors of 0.37. The ACR then shows better cost values.

		ENERGY AFTER LOSS	PERCENT OF INSOLATION
INCIDENT INSOLATION		3469 GWh _i	100
COSINE FACTOR	85%	2951	85
COLLECTOR BLOCKING/SHADING	91%	2695	78
RECEIVER BLOCKING/SHADING	100%	2695	78
EDGE LOSSES	100%	2695	78
MIRROR REFLECTIVITY	90%	2426	70
ATMOSPHERIC ABSORPTION	100%	2426	70
RECEIVER INTERCEPT	98%	2377	69
SEC CONCENTRATOR	100%	2377	69
TRANSMISSIVITY	91%	2163	62
ABSORPTIVITY	95%	2055	59
RADIATION	96%	1967	57
CONVECTION	86%	1701	49
LINE LOSSES	91% THERMAL TO EPGS:	1554	45
	30.5% GROSS ELECTRICAL OUTPUT:	475 GWh _e	13.7
	10.5% NET ELECTRICAL OUTPUT:	429	12.4

Figure 4-12. Annual Energy Efficiency Staircase
Aerospace Normalized BDM Design

		ENERGY AFTER LOSS	PERCENT OF INSOLATION
INCIDENT INSOLATION		2833 GWh _i	100
COSINE FACTOR	67%	1887	67
COLLECTOR BLOCKING/SHADING	100%	1887	67
RECEIVER BLOCKING/SHADING	96%	1817	64
EDGE LOSSES	91%	1661	59
MIRROR REFLECTIVITY	90%	1495	53
ATMOSPHERIC ABSORPTION	100%	1495	53
RECEIVER INTERCEPT	90%	1346	48
SEC CONCENTRATOR	97%	1309	46
TRANSMISSIVITY	91%	1191	42
ABSORPTIVITY	94%	1120	40
RADIATION	94%	1057	37
CONVECTION	83%	876	31
LINE LOSSES	94% THERMAL TO EPGS:	823	29
	42.4% GROSS ELECTRICAL OUTPUT:	349 GWh _e	12
	9% NET ELECTRICAL OUTPUT:	318	11

Figure 4-13. Annual Energy Efficiency Staircase
Aerospace Normalized GA Design

		ENERGY AFTER LOSS	PERCENT OF INSOLATION
INCIDENT INSOLATION		2891 GWh _y	100
COSINE FACTOR	70%	2024	70
COLLECTOR BLOCKING/SHADING	98%	1982	69
RECEIVER BLOCKING/SHADING	98.6%	1954	68
EDGE LOSSES	100%	1954	68
MIRROR REFLECTIVITY	90%	1759	61
ATMOSPHERIC ABSORPTION	98.7%	1737	60
RECEIVER INTERCEPT	88.8%	1543	53
SEC CONCENTRATOR	100%	1543	53
TRANSMISSIVITY	100%	1543	53
ABSORPTIVITY	95.8%	1478	51
RADIATION	90.5%	1337	46
CONVECTION	83.5%	1117	39
LINE LOSSES	94.5%	1056	37
	42.4% THERMAL TO EPGs:		
	GROSS ELECTRICAL OUTPUT:	448 GWh _y	15.5
	94.3% NET ELECTRICAL OUTPUT:	421	14.6

Figure 4-14. Annual Energy Efficiency Staircase
Aerospace Normalized SRI Design

		ENERGY AFTER LOSS	PERCENT OF INSOLATION
INCIDENT INSOLATION		3005 GWh _y	100
COSINE FACTOR	76.6%	2761	77
COLLECTOR BLOCKING/SHADING	96%	2651	74
RECEIVER BLOCKING/SHADING	99.8%	2646	73
EDGE LOSSES	100%	2646	73
MIRROR REFLECTIVITY	88.5%	2341	65
ATMOSPHERIC ABSORPTION	91%	2131	59
RECEIVER INTERCEPT	98%	2088	58
SEC CONCENTRATOR	100%	2088	58
TRANSMISSIVITY	100%	2088	58
ABSORPTIVITY	97%	2025	56
RADIATION	95.6%	1937	54
CONVECTION	94.8%	1836	51
LINE LOSSES	93.6%	1718	48
	41% THERMAL TO EPGs:		
	GROSS ELECTRICAL OUTPUT:	704 GWh _y	20
	90.7% NET ELECTRICAL OUTPUT:	638	17.7

Figure 4-15. Annual Energy Efficiency Staircase
Aerospace Normalized MM ACR

Figure 4-16. Envelope of Busbar Energy Cost, Aerospace Normalized Designs, BDM Turbine Parametrics

Figure 4-17. Envelope of Busbar Energy Cost, Aerospace Normalized Designs, GA Turbine Parametrics

Figure 4-18. Envelope of Busbar Energy Cost, Aerospace Normalized Designs, SRI Turbine Parametrics

Figure 4-19. Envelope of Busbar Energy Cost, Aerospace Normalized Designs, MM Turbine Parametrics

Figure 4-20. Envelope of Busbar Energy Cost, 100 MWe Turbine, Aerospace Normalized Designs

SECTION 5

LINE FOCUS APPLICATIONS

INTRODUCTION

Up to now, only large scale (≥ 100 MWe) electrical plant line focus applications have been studied. The technology identified in this program, however, can be applied to the many solar applications outlined in Figure 5-1. These applications are organized into three groups: electrical production, industrial process heat and total energy. Other smaller scale applications such as for residential and commercial energy were not covered; however, these markets will also intensify collector production and will have beneficial effects in reducing unit cost.

In this section the performance and energy costs of solar energy application noted in Figure 5-1 using the technology identified in this program are developed. The objectives of studying other markets are summarized below:

- Identify line focus market opportunities and market characteristics
- Identify collector technology requirements
- Support market penetration studies
- Support program planning.

The solar energy market potential and plant size and temperature characteristics are first defined. The penalties associated with forcing the line focus collector field within the boundary of available land are determined. A new electrical plant design taking advantage of the best from each of the contractor designs is then described. This is followed by a study of a hybrid version of this plant. Candidate line focus utility repowering systems including a regenerator repowering scheme that will add capacity credit to existing plants are then defined. Finally, the characteristics of industrial process heat plants using the technology defined in this program are outlined.

5.1 LINE FOCUS MARKET DESCRIPTION

Estimates for the potential market for line focus systems (LFS) in electrical power and industrial process heat were based on literature studies. The potential solar market to the year 2000 within the sunbelt region of the United States is shown in Figure 5-2.

5.1.1 Line Focus Market Size

5.1.1.1 Peak, Intermediate, Base Load Utility Market Size

The estimate for the utility market was taken from an SRI evaluation (Reference 3). SRI estimated the utility electrical generation capacity to the year 2000 by

Figure 5-1. Potential Line Focus Application

Figure 5-2. Summary of Potential Solar Markets

careful review of the requirements of 61 major electrical utilities representing approximately 75 percent of the total generating capacity of the western United States, and an estimated 90 percent of the total market. SRI started with existing capacity data from DOE, EEI and utility sources. The electricity growth was projected at 5.3 percent for the period 1975-1985, and 3.8 percent for the period 1985-2000. This was corrected for each category: base, intermediate, and peak for expected retirements (after 30 years) and expected transfers from base to intermediate units (<400 MWe and >15 years old). SRI's analysis indicates that by far the the greatest market potential for solar electric systems is for intermediate and peaking plants.

5.1.1.2 Solar Repowering Market Potential

A utility solar electrical repowering market has been identified as an early opportunity to commercialize solar systems. A recent Mitre survey (Reference 13) indicates that there is sufficient land available at these sites to repower approximately 18,000 MWe of utility capacity (Figure 5-2). A more conservative estimate of about 5000 MWe repower potential was made by Public Service of New Mexico (Reference 14) based on more restrictive conditions for suitability: less than 2500 ft pipe runs from field to existing plant, only non-reheat steam cycle, maximum plant size of 200 MWe, and at least 50 percent of the plant capacity to be repowered. The Mitre criteria allow for a 15,000 ft pipe run, reheat systems, no maximum size limit and no lower limit on the percentage of repowering when more than 150 acres (>25 MWe capacity) are available.

Both these estimates are expected to be reduced when other limitations, such as plant life, boiler cycling capability, economic and institutional and political constraints on the utilities, are considered. The LFS have the unique capability of utilizing odd shaped fields or even multiple field sections without severe cost penalties thereby increasing this solar market significantly (see Section 5.1.3).

5.1.1.3 Industrial Repowering Market

Mitre has estimated the industrial repowering market potential for the Southwest at about 100 billion kWh or 0.36 quads per year (Reference 13). This market is comparable in size to the Mitre estimate for the utility solar repowering market of 18,000 MWe capacity. This estimate is based on a 50 percent probability of land being available at the site.

5.1.1.4 Industrial Process Heat Market

The estimate of demand for industrial process heat was developed from a Battelle Laboratory study (Reference 15). Battelle predicts industry will require 12.4×10^{15} Btu per year of process heat by 1985 and 16.8×10^{15} Btu per year by the year 2000. The requirement for growth in the industrial process heat (IPH) sector was converted to equivalent electrical level for comparative purposes in Figure 5-2. The IPH market in terms of collector size is greater than that of the combined electrical market.

5.1.2 User Temperature Requirements

The line focus contractors were restricted by DOE to electrical steam turbine inlet temperatures greater than 700°F. A closer look at the inlet temperature characteristics of modern steam cycles indicates that competitive efficiencies are possible at temperatures below 700°F.

The input heat distribution of three steam cycles is shown in Figure 5-3. Even with the high temperature high pressure reheat cycle, 70 percent of the input heat enters the cycle at temperatures below 700°F. With the high temperature lower pressure cycle (1465 psi/950°F) typical of the Barstow pilot plant and small utility plants, some 85 percent of the heat enters the cycle below 700°F. The internal reheat steam cycles used in the nuclear industry operate at temperatures of 550°F and below and still maintain excellent efficiency.

Figure 5-3 indicates first that highly efficient systems can be designed at the lower temperatures. Secondly, lower temperature and near term technology can be used to repower the majority of the heat input plant equipment such as the economizer and evaporator of existing high temperature plants and still maintain a sufficient solar ratio.

From the figure it can be seen that as much as 25 percent of the initial internal cycle feedwater heating occurs in the regenerators operating in the temperature range from 110°F to 450°F. Considering the efficient operation of LFS at these temperatures, the potential exists that the overall system could be reoptimized to take advantage of this characteristic. This allows the steam that would normally be bypassed to the regenerators to flow straight through the turbine and increase plant output. This characteristic is pursued in greater detail for regenerator repowering (Section 5.4).

The temperature requirements of industrial process heat plants are outlined in Figure 5-4. Approximately two-thirds of process heat requirements fall below the temperature of 600°F.

5.1.3 Study of Cost Penalties Associated with Variations in Field Dimensions

The objective of the modularity study is to determine the sensitivity of line focus solar power plant capital costs to variation in collector field dimensions. The ability of a solar power plant to fit within the constraints of available land boundaries without large cost penalties improves the market share available to that plant. Unusual land constraints are normally found in solar retrofit of existing electrical and industrial process heat plants which are located in developed industrial areas where land is scarce and at a premium.

This study quantifies cost penalties for plants whose collector fields must be constrained to specific shapes and for single plants which, by necessity, require that their collector fields are physically separated by substantial distances. The cost penalties are calculated for both industrial process heat and electrical generation plants.

Figure 5-3. Heat Input Characteristics of Modern Steam Cycles

Figure 5-4. Industrial Process Heat Temperature Distribution

5.1.3.1 Study Assumptions

The baseline collector field size, piping layouts and costs were derived from the GA 100 MWe line focus solar power plant design (Reference 2). The procedures and results, however, are equally applicable to the other line focus configurations. The baseline GA collector field module layout, 900 ft long collector rows with coolant inlet from the side and coolant collection at the center, was used as the basic building block to develop field configurations of differing aspect ratios and for separated field designs.

GA optimized its field geometry without consideration of land constraints. Its key independent variables were length of collector rows, number of collectors per row, number of independent collector field modules, manifold arrangements, etc. Its optimization algorithm and specific constraints led GA to the field design shown in Figure 5-5.

The pipe dimensions used for sizing the heat transport subsystems for this study are shown in Figure 5-6. These data were also derived from the GA study. Pipe costs were optimized with regard to the costs of piping, pipe insulation, field increases to compensate for heat losses, heat tracing, pumping and trenches.

5.1.3.2 Study Methodology

Two types of field shape constraints were studied:

1. A single field with variation of the field aspect ratio.
2. Modular fields with two and four separate modules.

For this study the basic GA collector module consisting of the largest integral (or independent) unit of collectors was kept as a building block for the various field configurations. The GA independent module has dimensions of 1800 ft by 3062 ft.

Kept constant were subsystem efficiencies, equipment temperature constraints and output power requirements. Varied was the cost of piping, land and site preparation. There is also a slight cost penalty for the EPGS associated with the piping which runs from the central EPGS area to the cooling towers which are dependent on the field dimensions and incurs costs proportional to the lengths of these runs. Finally, the quantity of working fluid required by the plant and therefore cost is dependent on the total volume of the piping system. Some of the other plant subsystem costs are also slightly dependent on the collector field dimensions, but their variations on total plant cost are negligible.

The field aspect ratios that are investigated in detail in this report stem directly from the two extreme combinations that can be made with the basic GA collector field module. The nominal design, Figure 5-5, is a square configuration with one module in each quadrant. Its aspect ratio is 1.66. The two most natural alternate configurations to this design are an E-W grouping of these modules as shown in Figure 5-7a with an aspect ratio of 0.32, and a N-S stacking shown in Figure 5-7b with an aspect ratio of 8.14. The split field design is shown in Figure 5-8 where the collector modules have the option of being separated by substantial distances.

Figure 5-5. Nominal GA Field Layout; $L/W = 1.66$, $A = 24 \times 10^6 \text{ ft}^2$
(Equinox Noon Conditions)

Figure 5-6. Optimum HTS Pipe Diameters

Figure 5-7. Collector Field Layout Options

Figure 5-8. Segmented Field Design (Equinox Noon Conditions)

The calculation proceeds by first laying out a specific field design. The flow distributions required at various points in the field are then assessed. The chart of Figure 5-6 is then used to arrive at the optimal pipe sizes throughout the field and to determine heat transport system and other costs noted above. The collector and piping costs are then added.

5.1.3.3 Analytical Results

Table 5-1 gives a cost breakdown for the line focus solar power configurations shown in Figures 5-5 and 5-7. The percentage change in plant costs for both electrical and industrial process heat plants as a function of aspect ratio is shown in Figure 5-9. The percentage cost change for electrical plant costs is smaller since the capital costs are amortized over a larger plant total cost. The cost penalty for non-optimum electrical plants field configurations is below 2.5 percent over a wide range of field aspect ratios. The corresponding penalty for industrial process heat plants is below 10 percent for approximately the same range of aspect ratios.

Figure 5-10 shows the cost penalties imposed on a line focus plant that must accommodate substantial distances between collector field modules. The figure shows that plant cost increases as distances between collector modules are increased for both a four separate module configuration and a two module configuration. For both configurations the cost changes are minimal.

This study indicates that line focus solar power plants can accommodate wide variations in their collector field dimensions with minimal impact on the plant's capital cost. This allows a larger market potential for this type of solar plant especially for repowering or retrofit of existing electrical or IPH plants which are generally located in developed areas with severe land constraints.

5.2 "COMBINED" LINE FOCUS ELECTRICAL POWER SYSTEM

The objective of this section is to develop an optimal LFS stand alone power plant by combining the most effective design features and analytical approaches identified by the three line focus contractors. The design development was allowed to proceed without restrictions on operating temperature.

The selected approach was to combine the highly efficient parabolic trough solar collector subsystem with the high performance but lower operating temperature nuclear type electrical power generating subsystems.

The key design features and approaches selected for use in this study are listed below:

- T-2100 large aperture parabolic trough collector (BDM)
- Glass protected receiver tube operating at low average temperatures to reduce convection and radiation losses (BDM)
- Integrated collector field, heat transport configuration to minimize heat transport thermal losses and minimize piping size and costs (GA)

Table 5-1
CAPITAL COST PENALTIES

	<u>Description</u>	<u>Cost - \$1000's</u>		
5100	<u>Land, Site Preparation</u>	<u>L/W - 0.32</u>	<u>L/W - 1.66</u>	<u>L/W - 8.14</u>
	L/W Dependent Costs ⁽¹⁾	4,768	3,946	4,275
	Remaining Costs	434	434	434
	Directs	5,202	4,380	4,709
	Indirects	750	632	679
	Total	5,952	5,012	5,388
5600	<u>Heat Transport Subsystem</u>			
	L/W Dependent Costs ⁽²⁾	16,548	14,598	20,033
	Remaining Costs	11,830	11,830	11,830
	Directs	28,378	26,428	31,863
	Indirects	4,094	3,812	4,596
	Total	32,472	30,240	36,459
5800	<u>EPGS</u>			
	L/W Dependent Costs ⁽³⁾	2,526	1,000	474
	Remaining Costs	23,635	23,635	23,635
	Directs	26,161	24,635	24,109
	Indirects	3,774	3,553	3,478
	Total	29,935	28,188	27,587
	Remaining Field Directs	143,607	143,607	143,607
	Remaining Field Indirects	20,715	20,715	20,715
	Total Field Costs	232,681	227,762	233,756
	Engrg & Home Office @ 5%	11,634	11,390	11,680
	Total	244,315	239,152	245,444
	Contingency @ 14.2%	34,796	34,061	34,957
	Fee @ 3.75%	10,467	10,245	10,515
	Total Construction Cost	289,578	283,458	290,916
	Salt Cost ⁽⁴⁾	3,563	3,564	3,726
	Total Cost	293,141	287,022	294,642
	Cost per kWe	2,931	2,370	2,946

(1) These costs are proportional to the total field area.

(2) These costs are the total pipe related costs and are dependent on the piping layout.

(3) These costs are proportional to the distance between the EPGS and Cooling Towers.

(4) These costs are proportional to the total pipe volume and storage volume.

Figure 5-9. Percentage Change in Plant Costs vs Field Length to Width Ratio

Figure 5-10. Percentage Change in GA LFSP Capital Costs vs Distance Between Collector Modules

- Increased length of collector rows to reduce heat transport cost and increase collector efficiency (ALL)
- Single stage primary loop with high ΔT to reduce flow rate
- High ΔT across the thermal storage to increase storage effectiveness.

5.2.1 System Evolution

The evolution from the baseline BDM design to the selected configuration is illustrated in Figure 5-11. In column one are the cycle diagram and basic characteristics of the baseline BDM system. Due to the minimum temperature requirement of 700°F and maximum operating temperature (650°F) of the baseline T-55 loop, a second Syltherm 800 loop is required to superheat the steam to the required temperature. To generate a reasonable temperature drop and therefore reasonable flow rates, the pressure of the cycle is low and the EPGS efficiency suffers.

Adapting the nuclear industry developed steam cycle directly to the line focus collectors presents some problems. This cycle, shown in column two, operates at pressures of approximately 1000 psia and steam temperature of 550°F with internal reheat to 530°F and provides an impressive 36 to 38 percent gross cycle efficiency. Due to pinch point problems, however, combining this cycle directly with the solar loop results in a small collector loop temperature drop. This translates to an 80 percent higher HTS flowrate and a 90 percent higher thermal storage volume than for the BDM baseline.

A unique steam cycle with steam conditions and internal reheat as the nuclear cycle but with a higher primary loop temperature drop is shown in column 3. This is done by adding heat to the pressurized condensate to a temperature higher than that of the cycle operating temperature. This avoids the pinch point problem when heat is applied across the steam dome. The condensate is allowed to expand to the operating pressure and saturated steam is separated and directed to the turbine. More details on this cycle follow in the next section.

The net cycle efficiency drops to 32 percent due to a lower average heat input temperature, but the primary loop temperature difference of 320°F is twice that of the baseline case which translates to half the required flow rate and half the size of thermal storage. An additional benefit is that the average lower collector temperature improves the collector efficiency. There are numerous other advantages to this modified cycle as detailed below.

ADVANTAGES

Performance and Cost

1. Low average collector temperature increases collector efficiency due to lower convective and radiative losses.
2. Adequate steam cycle efficiency at 550°F due to reheat cycle.
3. High collector ΔT lowers HTS flow rate and therefore HTS pumping power and piping size and cost.

Figure 3-11. Application of High Pressure Nuclear Steam Cycle to Line Focus Technology

4. High storage ΔT increases specific volume effectiveness and lowers storage size and cost.
5. Use of low temperature, well known, low cost storage materials (oil/tac-onite).
6. Low temperature allows use of low cost carbon steel for all components.
7. Allows eventual use of near term lower temperature phase change materials.

TECHNOLOGY READINESS

1. Use of near term state-of-the-art collector technology
2. Use of developed components (turbines, HX, expansion tanks, steam separators, etc.)
3. Minor development costs due to system modularity and component state of readiness.

SYSTEM OPERATION

1. Modular nature of system improves availability and reliability
2. Low temperature improves operational and maintenance problems
3. Startup is easier and quicker due to low operating temperature
4. No fluid freezing problems
5. Simpler control procedures.

GROWTH POTENTIAL

1. A detailed analysis will improve steam cycle efficiency.
2. Expected near term technology developments such as low emissivity selective surface coatings and improved coolants will increase collector efficiency.
3. Technology adaptable to other applications.

5.2.2 Selection of the Preferred System Configuration

The system configuration chosen for the conceptual design study includes a single loop parabolic trough collector subsystem which provides T-55 coolant directly to the EPGS or to a single stage thermal storage subsystem. The steam cycle is equally rated whether operating from storage or directly from the receiver.

5.2.2.1 Busbar Energy Costs

Busbar energy costs were calculated for a constant plant turbine size (100 MWe) and various thermal storage and collector field sizes to minimize the cost of energy. The results, Figure 5-12, show that a minimum in the cost of energy occurring near a capacity factor of 0.6 corresponds to an optimum storage capacity of about 8 hr. The actual amount of storage installed, however, would depend on the utility plant application. A design close to the baseline contractor's size is selected for detailed description and comparison.

5.2.2.2 Plant Performance

The annual performance of the 100 MWe line focus plant with 8 hr of storage was determined using the Aerospace computer program described in Section 4. With the performance parameters developed from the subsystem designs, performance losses were determined on an annual basis for a location at Barstow, California. Figure 5-13 gives the annual energy staircase.

5.2.3 Conceptual Design

The power plant design concept is based on a steam Rankine cycle with heat provided by a single stage parabolic trough system. The steam Rankine cycle is a modified nuclear type, with internal reheat cycle and using regenerative feedwater heating. The solar portion of the plant is divided into two sections. T-55 is used as the working fluid in the receiver, primary heat exchanger and thermal storage.

5.2.3.1 EPGS Subsystem Design

The EPGS steam cycle shown in Figure 5-14 is a highly modified version of the nuclear industry developed internal reheat cycle. The turbine steam inlet conditions are identical to the nuclear cycle; however, the flow rates are changed as dictated by the new configuration.

The solar collectors are used to heat the pressurized condensate to a temperature of 625°F. The water is expanded to the turbine rated steam pressure (975 psi). The saturated steam is separated from the condensate. This steam is expanded in the high pressure turbine; condensate is separated from the turbine exhaust and the low pressure saturated steam is reheated by the condensate of expansion tank no. 1. This saturated liquid from the first expansion tank is further expanded to the pressure of the low pressure turbine; the steam is separated and along with the H.P. steam is directed to the low pressure turbines. The saturated liquid from expansion tank no. 2 provided most of the regeneration duty for the cycle.

This cycle is one example of many high performance cycles which are possible in the temperature range of 500 to 700°F and which are compatible with the lower temperature line focus collector systems.

5.2.3.2 Solid Field Design

The collector field configuration is shown in Figure 5-15. This design is an extension of the GA field design and intended to minimize the combined collector, heat transport and storage subsystem costs. The collectors are oriented in the north-south direction.

Figure 5-12. Energy Cost for "Combined" and Hybrid Plants

		ENERGY AFTER LOSS	PERCENT OF INSOLATION
INCIDENT INSOLATION		2944 GWh _t	100
COSINE FACTOR	85%	2504	85
COLLECTOR BLOCKING/SHADING	91%	2287	78
RECEIVER BLOCKING/SHADING	100%	2287	78
EDGE LOSSES	100%	2287	78
MIRROR REFLECTIVITY	90%	2058	70
ATMOSPHERIC ABSORPTION	100%	2058	70
RECEIVER INTERCEPT	98%	2017	69
SEC CONCENTRATOR	100%	2017	69
TRANSMISSIVITY	91%	1836	62
ABSORPTIVITY	95%	1744	59
RADIATION	97%	1692	57
CONVECTION	90%	1533	52
LINE LOSSES	99% THERMAL TO EPGS :	1522	51.7
	31.4% GROSS ELECTRICAL OUTPUT :	478 GWh _e	16.5
	93.7% NET ELECTRICAL OUTPUT :	440	15

Figure 5-13. Annual Energy Efficiency Staircase
"Combined Line Focus" Design

Figure 5-14. Modified Steam Cycle

Figure 5-15. Optimized Line Focus Power System

The field is made up of two independent collector modules. Two sets of collector rows are fed by cold fluid headers located at the east and west side of the field. The thermal storage cold tanks are located at the corners of the field (four in all). The working fluid is heated by the concentrators and collected by a common return line and the fluid directed to the hot tanks (one for each module). HTS costs are minimized by making the collector rows as long as possible - in this case, 2000 ft long or twice the length of the BDM collector row - letting them absorb the burden of flow distribution thereby minimizing HTS piping length.

By locating the TSS cold tanks at the corners of the field, the tank feed lines need only be sized for rated power rather than the full field power. In fact, only the lower ends of the return headers are sized for full power since header diameter is varied with flow rate demands.

5.2.3.3 Storage Subsystem

The storage subsystem has two cold tanks and one hot tank per collector module. Storage effectiveness is ensured by a high fluid ΔT of 325°F . Since oil does not freeze at the environments associated with the planned plant location, no trace heating is necessary.

5.2.4 "Combined" Plant Summary

Based on this preliminary analysis the following conclusions and recommendations are identified:

1. The low temperature parabolic trough combined with low temperature steam cycle provides excellent energy cost potential for the full range of capacity factors.
2. All components can be considered to be within the near term state-of-the-art technology.
3. The design has excellent growth potential which will further reduce its BBEC. The growth potential identified for BDM in Section 6 fully applies for this configuration.
4. This concept has been analyzed only in a crude preliminary manner. The potential demonstrated in this study deserves a full scale investigation to review and verify its performance and to identify potential problems.
5. The steam temperature range between 550°F and 700°F should be investigated to develop steam cycles of higher efficiency compatible with solar collector fields.

5.3 HYBRID POWER SYSTEM

The hybrid power system concept involves the use of the conventional storage coupled line focus solar plant combined with a nonsolar energy source. This source is used at times of poor insolation or when storage is depleted.

The advantages of this combined system are noted below:

- Permits capacity credit.
- Maximizes fuel displacement.
- Operational simplicity during cloud transients.
- Minimizes utility solar costs.
- Minimizes operating and maintenance costs resulting in high utility dispatch probability.
- Better utility acceptance.

In this study the hybrid plant consists of the lower temperature parabolic trough design described in Section 5.2 with the addition of the fossil heater and support equipment. The study objectives are to design the system (a) to produce minimum cost of electrical power and (b) high dispatch reliability.

5.3.1 Study Approach

The study is based on the maximum use of the characteristics of the "combined" line focus plant. The study assumptions include:

- Collector field, receiver, heat transport and EPGS configuration, performance and cost identical to solar stand alone
- Fuel oil fired heater
- Full fossil heater rating.

5.3.2 System Configuration

The hybrid plant consists of solar and nonsolar heat sources that drive a common conversion unit. Two candidate system schematics are shown in Figure 5-16. In the first case the fossil heater is in parallel with the solar collectors. In the solar heat source the T-55 coolant is heated in the receivers and delivered to the TSS hot tanks. The hot oil is used to generate steam for the turbine via oil-to-steam heat exchangers. For the nonsolar portion of the plant, the T-55 is heated in the fossil fired oil heater and delivered to the hot tanks. In the second configuration the steam generator is dual fired. It can either be actuated by the solar plant or steam can be generated by fossil fuel or a combination of both is possible.

The advantages and disadvantages of the two approaches are noted in Figure 5-17. In this study a choice of heaters is not made; however, the dual fired heater offers a number of advantages which deserve investigation in a more detailed study.

In both cases the large amounts of thermal storage are used to increase the plant capacity from the solar portion of the plant, minimize the busbar energy cost and fossil fuel usage. The hybrid configuration provides a plant that has the design and operational flexibility and potential economics to compete with conventional intermediate and perhaps even baseload plants using nuclear or fossil fuels.

Figure 5-16. Hybrid System Schematics

Figure 5-17. Candidate Fossil Heaters

5.3.3 Hybrid Plant Energy Costs

The levelized energy cost as a function of capacity factor is shown in Figure 5-12 and compared with the stand alone solar plant. Although the hybrid plant costs are somewhat higher than stand alone, the hybrid plant has the assured capacity credit in its favor.

5.4 LINE FOCUS SOLAR REPOWERING

Solar repowering combines the use of a solar heat source with a fossil heat source to operate a common turbine generator unit. Solar repowering using existing oil/gas fired steam plants with point focus solar heat sources has been investigated by DOE in previous studies (Reference 14). Currently DOE is investigating in detail several site specific repowering plant designs through a series of industry studies. The objective of this section is to determine the potential of line focus technology for near term repowering applications.

5.4.1 Repowering Benefits and Limitation

Solar repowering offers the utility and the nation several potential benefits as outlined below:

- Reduces consumption/imports of fossil fuels.
- Possible early commercialization (pre-1990) of solar thermal technologies.
- Demonstration of solar thermal technology to utilities.
- Begins production base required to reduce unit cost of collectors and receivers.
- May improve plant reliability and availability.
- Some application may increase plant capacity.

Solar repowering begins the process of conversion to renewable energy resources earlier than expected by operating in a redundant mode with existing fossil plants. Utility concerns for technical risk associated with new technology and the availability of insolation are minimized since the repowered plant will operate at full capacity and will provide the utility with discretionary control in the generation and dispatch of power when needed.

Repowering also offers a means for demonstrating solar technology to the utility in a cost effective manner and offers the solar developers a means to demonstrate and test their design techniques for large scale solar development.

There are a number of issues that need to be resolved to achieve a successful repowering program. Some of these issues are listed below:

- Plant lifetime short relative to new plant.
- Economics are not proven.
- Repowering market has not been adequately characterized.
- May not improve utility capacity after significant expenditures.
- Solar technology must be made available during repowering window (gas burning plants must repower between 82-90).
- Retrofit period eliminates revenue although capital and upkeep costs remain.
- Interface problems with existing plant including different levels of technology, additional support (electrical and mechanical) requirements, control interfaces, etc.

It is not the objective of this study to resolve these issues. These issues are being addressed by current site specific contractor studies. The objective of this study is to determine if the line focus technology possesses the fundamental characteristics which either will enhance the repowering program or prevent its participation in it.

5.4.2 Potential Repowering Market

The repowering market potential of 18,000 MWe noted in Table 5-2 was identified by The Mitre Corporation utilizing what it advised as optimistic assumptions including:

- Reheat/non-reheat plants
- Available land within 15,000 ft of plant
- 16 southwestern states
- No consideration of available solar insolation.

Public Service of New Mexico (PSNM) conducted a similar market survey in a 19 state region in the southwest. It identified 4580 MWe of small size (< 200 MWe) oil and gas fired units with sufficient land nearby with a total energy displacement of 0.2 quads. In this study land was assumed available within 2500 ft of the plant site.

In these two surveys it was found that approximately 45 percent of the candidate steam plants for repowering utilize reheat cycles and these are in general larger than 200 MWe. The solar repowering capacity of the reheat plants, then, represents approximately 80 percent of the total potential capacity estimated for repowering.

In both the Mitre and PSNM studies there were identified a number of factors which are likely to drastically reduce the market potential:

- Limited remaining fossil plant life
- Availability of solar plant technology at the time utilities must repower

- Shape and availability of land around plant site
- Fossil plant cycling capability
- Effect of available insolation on required land area
- Unit performance and O&M record
- Favorable economics
- Favorable solar/fossil operation and control.

The land requirements for repowering were assumed constant scaled to a small unit size (25 MWe), and would not be compatible with the larger units which represent the bulk of the capacity. Further, no difference in available insolation was assumed but this factor may lead to land requirements in some regions twice as much as in others. The survey did not investigate the suitability of the land around the unit.

5.4.3 Repowering Options

There are a number of options or power system configurations which will support the key DOE objectives of early commercialization and demonstration of technology. The steam cycle diagram shown in Figure 5-18 shows that solar heat can enter the steam cycle through a number of pieces of individual equipments and a variety of temperature ranges. The numbers associated with each component are the approximate solar fractions available if that component is repowered. The key message from Figure 5-18, as far as line focus is concerned, is that significant portions of the fossil plant can be repowered without exceeding the operating temperatures beyond the technology's current limits.

Table 5-2 presents a matrix of possible repowering options for utility steam electric plants. The table outlines how the solar heat is incorporated into the plant and identifies the line focus technology which has the capability of providing this heat. Selection of a particular option will depend on the detail plant engineering, plant operational characteristics, economics and other institutional and political factors which govern the utility selection process.

5.4.4 Repowering Configurations

Numerous configurations are possible for solar repowering of steam power plants. The specific configurations discussed below are for complete repowering of fossil boiler for reheat and non-reheat plant, repowering evaporator and economizer and regenerator repowering.

5.4.4.1 Repowering of Non-Reheat Cycle

The steam design conditions for non-reheat plants are approximately 950°F with pressures of 1450 psi. Only the SRI and GA technology has the potential to provide these steam conditions. The repowered plant configuration is shown in Figure 5-19. A thermal storage unit is shown in parallel with the solar receiver to buffer the turbine from cycling caused by weather conditions. Storage prevents inefficient operation of the fossil boiler during these transients which can result in large consumption for fuel by the fossil boiler to keep it on standby. This can negate the savings in oil or gas due to solar energy.

Figure 5-18. Repowering Options

Table 5-2
REPOWERING OPTIONS

<u>Repowering Option</u>	<u>BDM</u> ⁽¹⁾	<u>GA</u> ⁽²⁾	<u>SRI</u> ⁽²⁾
<u>Non-Reheat Plant</u>			
Feedwater Heater	XX ⁽³⁾	X	X
Econ/Evap	XX	X	X
Econ/Evap/Superheater		XX	XX
<u>Reheat Plant</u>			
Feedwater Heater	XX	X	X
Econ/Evap	XX	X	X
Econ/Evap/Superheat/ Reheat		XX	XX

1. Limited to 700°F steam temperature.
2. Capable of 1000°F steam temperature.
3. Large number of checks denote favorable application.

SOLAR CAPACITY/FOSSIL CAPACITY	0.8 TO 1.0
SOLAR FRACTION	0.2 TO 0.5
CAPACITY CREDIT	0.0
COLLECTOR TEMPERATURE	1100°F
STEAM CYCLE CONDITIONS	~1400 TO 1600 psia / ~950°F
AVAILABILITY	~1990

ADVANTAGES

- LARGER FUEL DISPLACEMENT
- PROVIDES BUFFER FROM SOLAR OUTAGES DUE TO WEATHER OR EQUIPMENT FAILURE

DISADVANTAGES

- TECHNOLOGY NOT DEVELOPED
- SERIOUS OPERATIONAL PROBLEMS
- INCREASED PLANT O&M
- LONG RETROFIT DOWNTIME
- DOES NOT SIGNIFICANTLY EXTEND PLANT LIFE

Figure 5-19. Non-Reheat Plant Repowering

5.4.4.2 Repowering of Reheat Cycle

A typical repowered reheat cycle configuration is shown in Figure 5-20. Again only the SRI and GA solar technology can provide the steam conditions (2400 psi 1000°F/1000°F) for this plant. Major advantages and disadvantages for line focus repowering of this configuration are listed in Figure 5-20.

5.4.4.3 Economizer and Evaporator Repowering

The economizer and evaporator repowering option is similar to the first two configurations except that the high temperature superheater and reheater are not repowered. This configuration is shown in Figure 5-21 along with a summary of its advantages and disadvantages.

In terms of line focus, the significant advantage of this configuration is the low temperature solar requirement which is within the near term capability of all the line focus technologies under study.

SOLAR CAPACITY/FOSSIL CAPACITY	0.8 TO 1.0
SOLAR FRACTION	0.3 TO 0.6
CAPACITY CREDIT	0.0
COLLECTOR PEAK TEMPERATURE	1100°F
STEAM CYCLE CONDITIONS	1800 psia OR 2400 psia/1000°F
AVAILABILITY	~1990

ADVANTAGES

- STORAGE PROVIDES BUFFER FROM WEATHER OR SOLAR OUTAGES
- MAY IMPROVE PLANT RELIABILITY/AVAILABILITY
- FOSSIL FUEL SAVINGS
- INCREASED FLEXIBILITY OF OPERATION BY CONSISTENT DELIVERY OF FUEL BY DIRECT SOLAR, THERMAL STORAGE OR FOSSIL BOILER

DISADVANTAGES

- SMALL MARKET
- COMPLEX INTEGRATION OF SOLAR PLANT
- OPERATIONAL PROBLEMS
- INCREASED O&M COSTS
- LONG RETROFIT DOWNTIME
- DOES NOT SIGNIFICANTLY EXTEND PLANT LIFE
- SOLAR TECHNOLOGY NOT YET DEVELOPED

Figure 5-20. Reheat Plant Repowering

SOLAR CAPACITY/FOSSIL CAPACITY	70 TO 90%
SOLAR FRACTION	0.3 TO 0.6
CAPACITY CREDIT	0.0
COLLECTOR PEAK TEMPERATURE	650°F
STEAM CYCLE CONDITIONS	1400 TO 2400 psia/400 TO 525°F
AVAILABILITY	~1985

ADVANTAGES

- OPERATIONAL SIMPLICITY
- NO CYCLING OF FOSSIL BOILER
- STATE-OF-THE-ART SOLAR TECHNOLOGY
- MODERATE RETROFIT DOWNTIME
- NEAR TERM APPLICATION
- LOW TEMPERATURE SOLAR

DISADVANTAGES

- INCREASED AVAILABILITY LOADS
- PLANT LIFETIME NOT APPRECIABLY IMPROVED
- INCREASED O&M COSTS

Figure 5-21. Economizer Evaporator Repowering

5.4.4.4 Solar Feedwater Heating

The solar feedwater reheat configuration is shown in Figure 5-22. For a single plant the solar fraction is small; however, this type of repowering is possible for all plants including large capacity plants which have been previously rejected for solar repowering on the basis of land constraints. A large plant of 800 MWe with regenerative repowering will retrofit approximately 100 MWe, which presents a more than adequate repowering effort.

5.4.5 Line Focus Repowering Analysis

Two types of repowering configurations are analyzed in some detail in this section: the boiler reheat cycle and regenerator heater repowering. The regenerator repowering is discussed in some detail since it was considered most promising for line focus applications.

5.4.5.1 Assessment Methodology

The economic criterion used for evaluation of retrofit economics is called the cost/benefit ratio. In this criterion all the costs incurred to the utility as a result of solar retrofit are allocated as cost. The savings incurred to the utility as a result of operation of the repowered plant into the utility grid over the life of the plant are allocated as benefit. The basic elements of these parameters are summarized below:

$$\text{Cost} = \text{Capital} + \text{Operation and Maintenance} + \text{Indirects} + \text{Utility Construction Downtime}$$

$$\text{Benefit} = \text{Total Fuel Saving} + \text{Fuel Warmup Cost} + \text{Capacity Credit}$$

Benefit or saving is defined here as the dollar value of solar to a utility (independent of the cost of solar) in terms of conventional power equipment not required, net savings in the system fuels (oil, coal fuel, etc.), and associated savings of O&M due to the contribution of the repowered plant. These savings are presented by a single discounted dollar value of a stream of savings that occur yearly over the operating life of the plant.

5.4.5.2 Reheat Plant Economic Assessment

A simplified utility system model (Figure 5-23) is utilized to determine the amounts and costs of all types of system fuel displaced as a result of solar repowering. Using the appropriate fuel cost and escalation rate for each type of fuel, the model then determines the present value of displaced fuel required in the calculation of cost to benefit ratio. Fuel expenditure due to fossil boiler operation is determined by the use of a hybrid simulation model.

The model analyzes the effect of solar repowering on a utility system by computing load duration curves associated with the total power generated from fossil fuel in the utility with and without solar repowering. Since in the static analysis

SOLAR CAPACITY/FOSSIL CAPACITY	10 TO 15%
SOLAR FRACTION	10 TO 15%
CAPACITY CREDIT	5 TO 13%
COLLECTOR PEAK TEMPERATURE	500°F
STEAM CYCLE CONDITIONS	450°F
AVAILABILITY	<1985

ADVANTAGES

- OPERATING SIMPLICITY
- BRIEF RETROFIT DOWNTIME
- STATE-OF-THE-ART SOLAR TECHNOLOGY
- NEAR TERM APPLICATION
- LESSER LAND CONSTRAINTS
- MAY PROVIDE CAPACITY CREDIT

DISADVANTAGES

- MAY USE DIFFERENT SOLAR TECHNOLOGY THAN FOR OVERALL PLANT REPOWERING
- UTILITIES MAY NOT BE INTERESTED IN SMALL SOLAR FRACTIONS
- PLANT LIFETIME NOT IMPROVED

Figure 5-22. Regenerator Repowering

- MEASURES ACTUAL ENERGY DISPLACED FOR EACH TYPE OF FUEL IN THE SYSTEM
- USES LOAD DURATION CURVES TO COMPUTE DISPLACED ENERGY AND SYSTEM-WIDE FUEL SAVING
- ACCOUNTS FOR POWER PLANT MIX AND DIFFERENT FUEL TYPES, ESCALATION RATES
- EXAMINES REPOWERING OF A GIVEN PLANT WITHOUT OTHERWISE CHANGING THE SYSTEM MIX

Figure 5-23. Utility System Simulation Model

assumption the plant mix does not change with time, the areas between the two load duration curves for each plant type in the utility are proportional to fuel displacement for those plant types.

The fuel expenditure of the repowered plant is estimated by a hybrid simulation model. The boiler operating losses associated with starting, shutdown, cycling, and standby operations are accounted for by reducing the energy displaced by a practical factor. The schematic drawing of the two load duration curves shows that solar repowering results in savings of gas, oil, and coal fuels even though the repowered unit is an oil fired plant.

A baseline case was chosen to correspond closely to one of the many cases investigated in the PSNM study. A 100 MWe intermediate oil steam plant in a synthetic PSNM utility is assumed to be repowered with a solar collector size of 233,000 m². The plant's performance is based on the Aerospace insolation tapes for Albuquerque, New Mexico. An Aerospace demand forecast for 1985 developed from Electric Power Research Institute (EPRI) data is used for the demand profile and load duration curves. The basic economic and system data shown in Table 5-3 are taken from Reference 11 and the 1978 EPRI Technical Assessment Guide.

Figure 5-24 compares the cost to benefit ratio of a line focus and central receiver repowered plant as a function of collector area. Using the plant characteristics provided by the contractor, the unit does not provide adequate return to the utility to compensate for its investment. It's also likely that the C/B value will increase when site specific factors are accounted for in the solar plant cost. In addition, the line focus technology at 1000°F has not had the development momentum to establish proof of principle prior to the time the utility would most likely make repowering decisions.

5.4.5.3 Adding Peaking Capacity by Solar Repowering

A study was performed to determine the feasibility of using low temperature solar feedwater heating on conventional fossil fired power plants to reduce the amount of fossil fuel required to preheat boiler feedwater, and to gain capacity credit. Solar feedwater heating takes advantage of unused turbine generator capacity by passing boiler steam completely through the turbine rather than using bypass flow for regenerative heating. Solar regeneration can be used for peaking capacity or with the use of thermal storage and can be used as a fossil fuel saver.

Basic Concept

A simplified schematic of the fossil plant with parallel feedwater solar heating is shown in Figure 5-25. Solar energy requirements are well within the operating range of parabolic trough T-2100 collectors using T-55 working fluid. Oil to water heat exchangers are used to transfer heat to the feedwater. The concept is useful for both reheat and non-reheat plants.

Solar energy is used in this study to heat feedwater and reduce the amount of steam extracted from the turbine. Reduced extraction steam requirements will enable either a reduction in throttle steam flow or increased generation when unused

Table 5-3
REFERENCE ASSUMPTIONS

- Plant to be Repowered
 - 100 Mw Intermediate Oil Plant
 - Site: Albuquerque, NM: Aerospace Insulation Data
 - Utility: PSNM: Aerospace Demand Data
- Solar Portion
 - Collector Area: 2 to 8 m²/kW_e
 - Run-of-the-Sun Operations: 100% Availability
 - No Storage
- Economic Scenario
 - Discount Rate: 11%
 - Fixed Charge Rate: 13%
 - Collector Cost: \$5.00/ft²
 - Indirect Costs: 40%
 - O&M Cost vs Capital Investment: 2%
 - O&M Escalation Rate: 8%
 - 1985 \$
- System Data

Type of Fuel	Nuclear	Coal	Oil Stream	Combustion Turbine	Pumped Storage
Capacity (MW)	260	1222	282	20	300
Availability (%)	80	80	80	90	99
Fuel Cost (\$/MBtu)	1.25	2.0	5.0	3.5	2.0
Heat Rate (Btu/kWh)	10,050	10,200	9500	14,000	13,000
Fuel Escalation Rate (%)	10	10	12	12	10

Figure 5-24. Repowering Cost/Benefit
Line Focus vs Central Receiver

Figure 5-25. Schematic of Solar Feedwater Heating System

turbine generator capacity exists. For the same generated kilowatt output, less steam will be required at the throttle valves. A net fuel saving results since less fossil fuel is consumed in generating the same output. When unused equipment capacity exists, the throttle flow can be held constant and the extraction steam replaced by solar heating can be used to increase the net generated output. A demand charge or capacity credit can be taken if this additional generation can be guaranteed.

Thermal energy storage was included in this study to provide a guarantee on the additional generating capability. An energy storage subsystem will make it possible to defer the utilization of solar energy to a period of increased load according to the utilities dispatching logic. It will also permit storing thermal energy generating by conventional means during periods of off peak load and solar outages.

The features and advantages of this solar concept are summarized in Table 5-4.

System Design

A preliminary design of the solar feedwater heating system of a conventional 100 MWe steam cycle was prepared to determine the basis for sizing components,

Table 5-4
BENEFITS OF SOLAR FEEDWATER HEATING

Add to Utility System Plant Capacity

- Potential to add up to 12 percent additional capacity to utility system
- Takes advantages of unused turbine generator capacity
- Reduces or eliminates fossil peaking plant purchase requirements

Effectively Reduces Fossil Fuel Requirements

- Reduces amount of fossil fuel to preheat boiler feedwater
- Effective utilization of solar energy
- No fuel wasted for warmup of fossil equipment

Simple Integrated Plant Operation

- Minor impact on conventional plant operation
- Does not disturb most complex part of conventional plant
- Simple integrated control
- Self regulating system
- Minor problems with transition between solar and conventional operations
- Uses internal plant energy to change storage during solar outages

Simple Technology Requirements

- Use of state-of-the-art collectors and thermal storage yield low development risk
- Low temperature technology
- Reduced technology requirements leads to low cost equipment with a greater potential for market penetration

Excellent Potential for Market Penetration and Application

- Can be used economically in existing or new plants
- Minor impact on plant operation during construction
- Potential for near term solar applications (pre-1985)
- Potential large market

Excellent Performance and Cost Potential

- Low temperature performance yields high collector efficiency
- Thermal storage requires state-of-the-art equipment operating at effective temperature drops

selecting feedwater equipment, estimating initial performance and cost and performing economic evaluations. For illustrative purposes the solar design is an adaptation of the T-2100 parabolic collector with T-55 working fluid and T-55/taconite thermal storage.

The solar feedwater heating system consists of a linear focusing solar collector/receiver subsystem, a thermal energy heat transport subsystem and a thermal energy storage subsystem integrated with an existing conventional steam power cycle. The flow cycle diagram (Figure 5-26) illustrates the design of the system to supplant the entire duty of the feedwater heaters.

When heating feedwater directly with solar energy, the T-55 fluid is pumped to the solar collectors where energy is absorbed by the fluid. From the solar collectors the T-55 is delivered to the shell side of the solar feedwater heaters, where it is heated and delivered to the boiler. Since the temperature of the feedwater entering the HP heaters is increased and the outlet temperature remains the same due to physical limitations, the extraction steam flow must decrease. This reduction of extraction steam usage is then converted to a fuel savings or a gain in generating output.

Charging of the thermal storage tank can be accomplished by using steam during the offpeak hours, or with fluid heated in the solar receiver. When steam is used, it will be delivered to a charging heat exchanger which transfers heat from the steam to the energy storage medium. A brief description of the major solar subsystem follows:

Solar Collector/Receiver Subsystem

The primary function of the collector/receiver subsystem is to collect solar insolation, convert it to thermal energy and conduct this energy into a heat transfer medium. The main component of this subsystem is the T-2100 linear focusing parabolic trough collector. The output temperature of the T-55 working fluid is 520°F and the average collection temperature is 330°F. At this low average operating temperature, collector effectiveness improves to 71 percent.

Energy Transport Subsystem

The energy transport subsystem transports and conducts the energy absorbed at the receiver to either the boiler feedwater of the main steam power cycle or the thermal energy storage system. This subsystem will consist of a transport medium, a solar feedwater heat exchanger, solar feed pumps, piping, valves and a thermal expansion tank. The basic material for this system is carbon steel.

Thermal Energy Storage Subsystem

The T-55/taconite thermocline design has been tentatively selected for the thermal energy storage subsystem. The thermocline would operate between temperatures of 150°F and 520°F which are less demanding conditions than current technology thermocline designs. During periods of low insolation the thermal storage can be charged using steam from the boiler steam drum which transfers its heat to the T-55 via a thermal storage charging heat exchanger.

Figure 5-26. Solar Feedwater Heating Subsystem Integrated with Conventional Steam Plant

System Performance

The performance of the solar feedwater heating system was measured by the heat rate gain and capacity factor improvement when the solar unit is operating. The change in plant capacity and heat rate is shown in Figures 5-27 and 5-28 as a function of regenerating capacity displaced. An improved heat rate occurs when solar is collected and less fuel is used to maintain the plant's rated power. An increase in output would occur when the fuel rate is kept constant while solar does feedwater heating and the increased flow of steam is directed completely through the turbine. The potential fuel saving for a representative 100 MWe oil fired plant is shown in Figure 5-29.

Economic Analysis

The economics of the solar feedwater system were evaluated on the basis of the cost to benefit ratio. Fuel savings and capacity credits were calculated for systems which displaced solar energy for a range of operating hours. The parameters used in the economic evaluation are as follows:

- Remaining Plant Life: 30 years
- Solar Equipment Life: 30 years
- Levelized Fixed Charge Rate (LFCR): 16 percent
- Present Day Cost of Fuel: \$5.00 per Btu (oil) after 1985 mn
- Annual Fuel Escalation Rate: 12 percent
- System Operating and Maintenance Cost: 1 percent
- Cost of Capital (discount rate): 11 percent
- General Inflation Rate: 7 percent
- General Escalation Rate: 7 percent
- O&M Escalation Rate: 8 percent

The cost to benefit ratio for the plant as a function of number of operating hours per day and collector specific cost is shown in Figure 5-30. The C/B ratio looks extremely promising for both Nth plant collector costs and for collector costs closer to today's value. Additional costs will certainly arise when detail engineering is performed on a site specific configuration. However, regenerator repowering is economically promising and will meet other DOE and utility requirements for demonstrating technology and development of a near term market. The concept deserves further study.

5.5 INDUSTRIAL PROCESS HEAT

The objectives of this section are to determine the applicability and potential benefits of the line focus technology to the industrial process heat (IPH) solar program. The line focus technology is compared to central receiver for this application.

DOE has initiated a number of programs to develop solar process heat technology and applications studies for industry to stimulate and give impetus to industry to use solar energy for industrial processes. DOE's Agricultural and Industrial Process Heat Branch is working with DOE laboratories and industry in the development of solar heat energy applications to industrial processes in three areas:

Figure 5-27. Potential Increase in Plant Capacity as a Result of Solar Feedwater Heating

Figure 5-28. Potential Improvement in Fossil Fuel Heat Rate Due to Feedwater Heating

Figure 5-29. Potential Fuel Savings for 100 MWe Plant Using Solar Feedwater Heating

Figure 5-30. Regenerator Repowering with Line Focus Collector

- Low temperature (below 212°F)
- Intermediate temperature (212°F to 350°F)
- High temperature (above 350°F).

The low temperature industrial process heat experiments and prototype systems pertain to applications in which temperatures under the boiling point of water are required. Applications include the heating and cooling of buildings and agricultural applications. Intermediate temperature process heat applications include production of low pressure steam for industrial uses, and for various drying operations. High temperature process heat systems include production of high pressure steam, heat for chemical processes, and other industrial uses of solar energy.

DOE is also funding additional studies to develop detailed site specific conceptual designs that provide practical and effective use of solar energy for new or retrofit industrial process heat plants. The intention of this procurement is to provide DOE potential users and the public with (a) definition of IPH designs, (b) preliminary estimates of potential technical and economic benefits of solar IPH, (c) cost and schedule data, and (d) identify the potential IPH market. The technology emphasis in this program is the central receiver point focus concept.

3.5.1 Objectives and Scope of Current Study

The objectives of this study are summarized below:

- Identify the performance cost characteristics of the new line focus technologies identified in this program as applied to IPH applications.
- Determine the variation in line focus IPH systems characteristics as a function of process temperature and plant size.
- Compare LFS technology with central receiver for IPH applications.

The work scope required to accomplish these three objectives includes the following: review of IPH market process temperature and size characteristics; prepare line focus designs which produce the noted temperature and sizes; and compare these designs with competing point focus central receiver concepts.

The specific designs developed are rated at 300 MWt (at summer solstice) for operating temperatures of 375 to 600°F, 60 to 300°F and 60 to 200°F. The 375 to 600°F process temperature system size was then varied between 50 and 1000 MWt to determine the effect of field size on plant characteristics.

Only the line focus parabolic trough technology was studied for this application. However, both the fixed mirror and single axis systems are capable of generating process steam.

5.5.2 Industrial Process Heat Market

A large potential industrial process heat solar market has been identified as noted in Section 5.1. The characteristics of that market are further refined now to determine the requirements of solar plants to meet this demand.

Figure 5-4 shows the temperature distribution of energy produced in industrial process heat plants located in the American sunbelt. The bulk of the energy, particularly at temperatures below 600°F, is utilized as steam process heat.

Although the bulk of the steam is produced at temperatures from 450°F to 600°F, more than 40 percent of the energy is used at temperatures below 300°F. This seeming anomaly is explained by the fact that most large plants will have two systems of steam piping, a high pressure system and a low pressure system. Although the steam is initially procured for the high pressure system to satisfy a few applications such as compressor or generator turbine drives, it is then reduced to the low pressure level for the bulk of the process heating.

The nonsteam, primarily high temperature, applications are for furnaces, gas turbines and other engines for shaft power, heaters, and direct fired reactors. Approximately 50 percent of this energy is provided by miscellaneous fossil fuels such as oil or gas and the remainder are fuels which are byproducts of the plant process itself.

In summary, the bulk (>60 percent) of the energy requirements of American industry is required in the form of process steam at temperatures below 500°F. These temperatures are well matched with the capabilities of line focus systems. The bulk of the remaining process heat demand is for temperatures greater than 1000°F.

Figure 5-31 shows the process steam energy distribution on the basis of plant size. Approximately 50 percent of the energy is associated with plants which require 300 million lb of steam per hour. As will be noted later, the economics of solar systems favor the larger plant sizes.

5.5.3 Analytical Model

The basic solar process heat analytical model is shown in Figure 5-32. The rated plant thermal power level is shown at the end of the efficiency chain. Solar collectors (line or central receiver) are used to gather the sun's energy where it is collected by the receiver. The appropriate losses are applied at these components. The heat transport subsystem is used to centralize the energy collected where it is converted to process steam. Since energy must be consumed to centralize and convert solar energy to process steam, a pumping power penalty is applied which must be collected in addition to baseline requirements. A 20 percent thermal to electrical efficiency is used to assess this penalty.

The following assumptions were used in the study:

Figure 5-31. Cumulative Distribution of Industrial Process Heat Load

Figure 5-32. Industrial Process Heat Model

- The solar generated load profile was assumed acceptable to the IPH process without management.
- No thermal storage or fossil boost.
- Central receiver configurations, cost and performance were based on Reference 8 (Nth plant costs).
- The line focus costs and performance were based on the BDM collector field design (Nth plant costs).

5.5.4 Analytical Procedures

The analytical process to develop IPH systems specific costs is outlined below:

A. 300 Megawatt IPH System with Variable Process Temperature

- (1) The parabolic trough and point focus system efficiencies are calculated for a 300 MWt system at the three process temperatures for the summer solstice design point. The results are noted in Table 5-5.

Table 5-5
HTS DESIGN POINT DATA - 300 MWt
(Summer Solstice)

Process Temperature (°F)	Line Focus			Central Receiver		
	Efficiency	Solar Insolation (MWt)	Aperture Area (ft ² x 10 ⁻⁶)	Efficiency	Solar Insolation (MWt)	Aperture Area (ft ² x 10 ⁻⁶)
600	0.673	432	4.9	0.63	219	5.60
300	0.705	408	4.43	0.637	492	5.35
200	0.708	387	4.19	0.64	495	5.38

- (2) The required solar input and glass aperture areas for the same conditions are developed. The result of this calculation also are noted in Table 5-5.

- (3) The annual system efficiencies are then calculated as a function of process temperature (see Figure 5-33).
- (4) Field parasitic loads are then calculated and noted in Figure 5-34. The large central receiver pumping power is based on overcoming the large head loss of the tower. Tower height as a function of power level was taken from Reference 16.
- (5) The resultant systems annual energy production is noted in Table 5-6.
- (6) The plant capital and annual costs for the systems sizes identified above are noted in Table 5-7.

B. Variable Plant Size at Constant (600°F) Process Temperature

The output characteristics of solar plants will change significantly with plant rating. As the plant rating drops, the line focus specific pumping power will increase significantly due to a higher ratio of HTS piping to the receiver piping. Shorter collector rows will reduce optical efficiency due to end losses and will have the effect of increasing the support equipment, such as drives and controllers required per unit aperture area. Conversely, for the central receiver systems a smaller size will result in lower parasitic losses since tower heights are shorter and the average field efficiency is higher due to the fact that the inner rows of collectors are the most efficient.

The variable plant size calculation procedures are summarized below:

- (1) The design point efficiencies and resultant required incident solar insolation and aperture areas are noted in Table 5-8.
- (2) The annual efficiencies and parasitic powers are noted in Figure 5-35.
- (3) The resultant annual energy production is summarized in Table 5-9.
- (4) The plant capital and annual costs are summarized in Table 5-10.

5.5.5 IPH Study Results

This study is a first order survey of IPH characteristics since detailed analyses, such as process load profile, cloud cover, shape of available land, economic conditions, were greatly simplified. The selection of the optimum solar technology for IPH applications is strongly dependent on the cost of the collector. With regard to the limited objectives of this study, the following conclusions apply:

- The line focus technology identified in this program is well matched to IPH applications.

Figure 5-33. Collector System Efficiency

Figure 5-34. System Parasitic Losses

Table 3-6
ANNUAL ENERGY GENERATION - 300 MWt

Process Temperature (°F)	Energy Generation (Btu x 10 ⁻¹²)	
	<u>LFS</u>	<u>PFS</u>
600	2.57	2.768
300	2.577	2.8
200	2.6	2.85

Table 3-7
PROCESS HEAT ENERGY COSTS - 300 MWt

System Process Temperature (°F)	<u>LFS</u>			<u>Central Receiver</u>		
	600	300	200	600	300	200
Collector Receiver	26.98	24.338	23.04	44.5	44.11	44.38
Tower	1.37	1.23	1.17	1.41	0.348	0.4
BOP including land	12	12	12	14	14	14
Total Capital Cost (\$10 ⁶)	40.35	37.57	36.21	61.9	58.458	58.77
O&M Cost 3.4% of Capital Cost	1.387	1.29	1.245	2.128	2.0094	2.02
Annualized Capital Cost (\$10 ⁶)	7	6.516	6.28	10.736	10.10	10.2
Annual Cost (\$10 ⁶)	8.387	7.806	7.525	12.864	12.15	12.213
Levelized Energy Cost (\$10 ⁶ Btu)	3.26	3.03	2.894	4.63	4.33	4.28

Table 5-8
IPH SYSTEM DESIGN POINT DATA - 600°F

Plant Size (MW _t)	Line Focus			Point Focus		
	Efficiency	Solar Insolation (MW _t)	Aperture Area (ft ² × 10 ⁻⁶)	Efficiency	Solar Insolation (MW _t)	Aperture Area (ft ² × 10 ⁻⁶)
50	0.68	73.2	0.795	0.68	73.2	0.854
300	0.745	408	4.9	0.657	497	1.64
1000	0.745	1362	14.8	0.637	1779	19.32

Figure 5-35. Annual Plant Efficiency as a Function of Plant Size

Table 5-9
ANNUAL ENERGY CALCULATION - 600°F
(Btu x 10⁻¹²)

<u>Plant Power (MWt)</u>	<u>LFS</u>	<u>PFS</u>
50	0.447	0.5113
300	2.577	2.807
1000	8.738	8.63

Table 5-10
PROCESS ENERGY COSTS - 600°F
PROCESS TEMPERATURE

<u>System Plant Size (MWt)</u>	<u>LFS</u>			<u>Central Receiver</u>		
	<u>50</u>	<u>300</u>	<u>1000</u>	<u>50</u>	<u>300</u>	<u>1000</u>
Collector Receiver	4.4	26.98	81.4	7.05	46.5	159.4
HTS	0.22	1.37	4.16	0.214	1.41	4.848
BOP	6	12	24	7	14	28
Total Capital Cost (\$/10 ⁶)	10.66	40.35	109.56	10.264	61.9	192.23
O&M	0.362	1.387	3.725	0.485	2.128	6.536
Annual Capital Cost (\$/10 ⁶)	1.85	7	19	2.474	10.736	33.34
Annual Cost (0.173%)	2.2	8.387	22.727	2.959	12.864	39.88
Levelized Energy Cost (\$/10 ⁶ Btu)	4.95	3.26	2.6	5.78	4.65	4.62

- The line focus and central receiver annual efficiencies are approximately equal. For larger plants, greater parasitic losses with the point focus plant give the line focus system a slight performance edge.
- Annual energy costs are better for line focus plants for the process temperatures studies due to lower collector costs. The line focus advantage is accentuated at lower process temperatures due to lower receiver losses.
- Line focus cost advantages improve with increased plant size. This is due to improved line focus efficiency with size and a loss in efficiency with larger field sizes for the central receiver plant. These effects are reversed at smaller plant sizes.
- Current process heat studies should be reviewed to include the advanced large aperture, glass reflected T-2100 collector technology.
- Development of the T-2100 collector technology will complement both electrical and IPH applications. Pursuit of both applications with the same solar technology will accelerate the achievement of lower unit production cost objectives.

SECTION 6

GROWTH POTENTIAL

Each of the contractors has identified potential areas of improvement in component and system design, manufacturing, and performance which can be expected to further reduce annual energy costs. These improvements are discussed in this section.

6.1 IMPROVED PERFORMANCE

Table 6-1 shows the potential performance improvements possible for the line focus systems. These improvements are mainly the result of improved materials properties, materials which are under development at this time and should be available in the 1980s. The development of low emissivity surface coatings will substantially improve receiver efficiency for BDM and GA. The SRI design already assumes the use of this type of coating.

The BDM design, because of its lower temperature, has potential for power conversion cycle efficiency improvement as higher temperatures become accessible due to the improved receiver coatings. A more detailed steam cycle analysis at the lower temperatures, using nuclear type high pressure reheat cycles, may show increased performance even before the improved coatings become available. The potential for performance growth in the BDM design is to 46 percent.

GA believes collector performance can be improved by use of slightly curved mirror strips which reduce light spillage. Improvements in the receiver can be realized by reducing the infrared (IR) emission with a suitable IR reflective coating on the innermost receiver surface. At the same time, the use of a solar anti-reflective coating on the outermost surface can reduce the reflection of the incoming concentrated insolation. If the above developments are successful, overall performance improvement of 36 percent can be projected for GA from the appropriate combination of the above factors.

Since the SRI study assumes the use of advanced coatings, and since the designs of the EPGS, HTS, and ESS already represent the best commercially available equipment, performance improvements are limited.

6.2 IMPROVED DESIGN

Component cost improvements due to improved design are identified in Table 6-2. For each of the contractors potential improvement is greatest with its collector design. GA sees improved economics by fabricating the primary concentrator panel from a lightweight material so that it can be factory manufactured rather than field assembled. Such a material would need adequate stiffness, strength, and resistance to environmental exposure and should be of low cost. A material having these properties appears to be fiberglass reinforced foamed polyurethane. A corollary to

Table 6-1
SOLAR SYSTEM GROWTH POTENTIAL

<u>SOURCE</u>	<u>BDM</u>	<u>GA</u>	<u>SRI</u>	<u>SAFECR</u>
<u>IMPROVED PERFORMANCE</u>				
1. Low Emissivity Coating	1.08	1.11	1.0	1.01
2. Mirror Reflectivity (0.9 to .92)	1.02	1.02	1.02	1.02
3. Reflectivity of Secondary Conc. (from .88 to .92)	1.0	1.003	1.0	1.0
4. Curved Reflective Glass	1.0	1.12	1.0	1.0
5. Higher Glass Transmission (.91 to .93)	1.02	1.02	1.0	1.0
6. Optimized Steam Cycle	1.133	1.0	1.0	1.0
7. Higher Operating Temperature	1.10	1.0	1.0	1.0
Total Potential Improvement	1.44	1.36	1.03	1.03

Table 6-2
COST REDUCTIONS DUE TO IMPROVED DESIGN

GA

- Lightweight factory assembled concentrator panel
- Wider panels
- Improved receiver truss design
- Longer receiver and collector rows
- HTS reoptimization to minimize high cost of trace heating and trenching

SRI

- Reoptimize design of trace heating
- Redesign of tree tank thermal storage
- Replace plastic reflector backing with GRC
- Review tradeoff between number of collector rows and length of receiver the HTS

BDM

- Minimize structural weight of T-2100 collector
- Optimize steam cycle collector combination
- Increase effectiveness of thermal storage

using a lightweight panel is reduced handling and shipping costs and reduced foundation costs. In addition, it would be possible to make the panels a little wider and still retain their ease of handling. Increasing the panel width can increase the geometric concentration ratio and reduce the receiver thermal losses. Most important, however, is the fact that factory assembled concentrators provide cost reduction due to the learning process associated with automated mass production which GA could not claim with its current, site fabricated concrete collectors.

SRI estimates that significant capital cost reduction for the heliostat have been identified in two particular areas based on alternative design approaches. The first is the substitution of glass reinforced cement (GRC) for the plastic sheet molding compound in the reflector backing. This would reduce cost by approximately \$1.50/ft² of reflective backing. The second cost saving can be achieved by accounting for mutual wind shielding of adjacent rows of concentrators and inclusion of wind fences. This would reduce wind loads on the heliostat and reduce structural requirements both on the heliostat and the foundation and pedestals.

The current T-2100 structural design is conservative and has significant potential for cost reduction resulting from a weight reduction program.

6.3 IMPROVED MANUFACTURING/ASSEMBLY

Potential manufacturing and assembly cost reduction techniques are noted in Table 6-3. Each technique supports the efforts to improve the manufacturing learning curve. The extent of the possible cost reduction as a result of improved design and manufacturing techniques cannot be estimated at this time.

Table 6-3

IMPROVED MANUFACTURING AND ASSEMBLY TECHNIQUES

1. Amortized tooling and setup⁷ costs with higher throughput
2. More automation with higher throughput
3. Lower cost materials from higher throughput
4. Better trained manufacturing/assembly workers
5. Automated foundation assembly

SECTION 7

DEVELOPMENT ISSUES

7.1 INTRODUCTION

This section briefly summarizes the significant technology development issues for the line focus plants. These issues are summarized in Tables 7-1 to 7-3.

Table 7-1

BDM DEVELOPMENT ISSUES

Stability of Black Chrome Selective Coating
High Temperature Fluid Development
Stability of Thermal Storage Materials
T-2100 Collector Development

Table 7-2

SRI DEVELOPMENT ISSUES

Low Emissivity Selective Surfaces Development
Glass Reinforced Concrete Heliostat Development
Receiver Freeze-up
Receiver Construction Technique
Receiver Performance Characterization
Molten Salt Technology

7.2 SOLAR SELECTIVE ABSORPTIVE COATINGS

The performance and economics of each of the plants are very sensitive to absorptive coating properties. These coatings must have a high solar absorptivity, a low infrared emissivity, and long term stability in air at temperature. Selective coatings are being developed which show promise; however, none has been tested in air for extended periods of time. The stabilized black chrome coating of the T-2100 collector is perhaps best known, but it must demonstrate stability over an extended period. The selective surface coatings selected by SRI and GA are still laboratory devices.

Table 7-3
GA DEVELOPMENT ISSUES

Development of Selectively Absorptive Coating that Gives Good Stable Performance in Air up to 1100°F

Demonstration that Advanced Continuous Casting of FMSC Concrete Panels Will Attain Cost and Performance Goals

Verification of Operability of Hot Salt Collector Array Utilizing Overnight Line Drainage

Molten Salt Technology

Effective Mirror Edge Seals

Mirror Resistance to Hail

7.3 CONCENTRATOR DEVELOPMENT

Each of the concentrators identified by the contractors requires extensive development. The T-2100 parabolic trough design is based on the existing T-700 collector and should be the easiest to develop. Key issues are the substitution of steel for aluminum structure, modular construction approach, and glass reflective surface development.

While there are some commercial analogies to the GA concrete fabrication techniques, the entire fabrication process has not been proven. It is essential to demonstrate that the fabrication method will achieve the desired cost and performance goals. The latter depend principally on achieving the desired precision of the mirror strips (3 σ of ± 15 min). The following elements are required:

1. Establishing that secondary concrete forms made from a steel master will have the desired precision.
2. Establishing that the concrete panels obtained from the secondary concrete forms fall within the specified angular tolerance.
3. Establishing that the glued-on mirrors meet or exceed the overall angular accuracy requirements.
4. Developing a rapid technique for measuring the angular accuracy of the facets on the concrete panels so as to achieve good quality control.
5. Demonstrating that the cost goals are indeed achievable.

The SRI heliostat is the least developed concentrator. To demonstrate the heliostat the following developments are required:

1. Glass reinforced cement (GRC) technology

Measurement of GRC properties for durability and manufacturing techniques.

2. Heliostat construction

Build a heliostat module with GRC for measurement of properties, durability, and study of manufacturing techniques.

3. Reflective surface construction

Build reflective surface with GRC substrates for measurement of properties, durability, and study of manufacturing techniques.

SRI also suggests that to reduce heliostat costs even further the plastic mirror substrate be replaced by low cost GRC material. To verify this technology the following tests are required:

1. Stress and deflection analysis of GRC substrate
2. Mirror/GRC adhesives analysis
3. GRC weight and material cost estimates
4. GRC production techniques analysis
5. Substrate experiment: experiment design and cost estimate.

7.4 RECEIVER DEVELOPMENT

The SRI system performance depends on proof of low convective losses on the extensive receiver surfaces. Tests must be performed to measure wind velocities inside the cavity and demonstrate low convective losses.

The GA receiver design concept has already proven in previous tests that it is an effective device. This is an indication that the advanced design identified by GA in this study will meet its performance goals.

7.5 SALT TECHNOLOGY DEVELOPMENT

The salt technology development currently under way as part of the point focus central power system is necessary to the economic success of the SRI and GA systems. These developments are:

1. Molten salt metallurgy
2. Molten salt equipment development
3. Molten salt storage techniques.

Type 316 stainless steel has been selected by SRI and GA for the hot portions of the salt components ($>800^{\circ}\text{F}$) and carbon steel for the low temperature ($<800^{\circ}\text{F}$)

portions. Long term exposure of 316 SS and other candidate materials to molten draw salt at temperatures of 1050°F is not well documented. The data in the literature are scarce and incomplete. Corrosion allowances to be used for design purposes are considered arbitrary. Long term exposure data are needed which encompass crevice corrosion, galvanic effects, stress in the base material, and the effect of impurities in the draw salt.

The hot salt pumps and valves must be demonstrated for continuous operation. Utilities must be convinced that operation of salt loops can be done without significant problems of reliability and O&M.

In addition, the cyclical operation of each of the line focus plants imposes startup and shutdown limitations (from temperature transients) on the plant components, particularly the turbine and the steam generator. The impact of these limitations on the plant availability and its economics needs to be explored.

SECTION 8

CONCLUSIONS

The potential of line focus designs for large scale electrical power applications and some of the important issues concerning line focus systems are summarized below. The issues addressed include technical, performance and cost goals, technology requirements, and market potential.

8.1 GENERAL CONCLUSIONS

- All three contractors performed careful, thorough, and technically responsive studies. As might be expected, however, there remains a substantial uncertainty over annual energy costs.
- There are no fundamental technical limitations on the deployment of any of the proposed line focus systems up to power ratings of 300 MWe given that the development issues outlined below are achieved.
- Each of the contractor designs will require additional development and system integration effort to obtain the performance levels defined by them.
- Two of the line focus system (LFS) contractors claim lower busbar energy costs than the first generation strawman point focus system; only the parabolic trough design, however, appears to have the potential to match the advanced central receiver system (ACR) cost performance goals.
- The full potential of advanced second generation parabolic trough systems was not completely identified in the contractor study. Of particular interest would be to match the single stage parabolic trough collector system operating at lower temperatures combined with high efficiency conventional steam cycles, similar to those currently used by the nuclear industry which operate at steam conditions of 550°F and 1000 psia (see Section 5.3).

8.2 COMPARISON OF CENTRAL RECEIVER AND LINE FOCUS SYSTEMS

A rigorous comparison of the two technologies is, at this time, difficult to accomplish due to lack of definitive performance and cost data for all concepts, and due to the different technology development philosophies of the two solar communities. Even a heavily funded detailed evaluation, based on the review of manufacturing drawings, fabrication processes, installation procedures, and review of performance data, etc. would not today provide a definitive answer, since some of the components under the study have not passed proof of principle as yet. As a further example of the difficulty of this problem, even a cost comparison of basic components such as heliostats and parabolic troughs could be misleading due to different design approaches taken by the developers. The heliostat community has emphasized advanced mass produced cost effective design to provide cost goals for the future, while the line focus community stresses prototype construction and test.

As a result the line focus designs may be somewhat more conservative than their central receiver counterparts.

The comparison approach utilized in this report, then, can best serve to identify leading candidates and key technology issues. With this understanding the following points of comparison are offered:

- The GA and SRI high temperature salt systems, though less risky than ACR due to lower concentration ratios, show less promise than the ACR salt system and, to a large extent, their further development would be a duplication of effort.
- The advanced central receiver system appears superior to the three LFS configurations studied at the high plant capacity factors associated with base load utility units.
- The lower temperature parabolic trough appears to be an excellent candidate for large power system applications especially in the peaking and intermediate capacity factor regions. This is the area in which solar plants are most likely to penetrate the utility market. Further, single stage lower temperature parabolic trough technology in combination with the low temperature internal reheat steam cycle technology of the nuclear industry should increase this system's cost effectiveness throughout the capacity factor range.
- The line focus collector hardware appears to be inherently less costly than central receiver heliostats due to fewer and less intense structural loads, inherent structural stability provided by multiple supports, fewer drives, actuators, power supplies, and controllers per unit aperture area, lower installation costs due to field linearity, simpler components, lower weight, and ground level construction. Also, O&M costs for line focus systems appear to be lower than central receiver systems due to fewer pieces of equipment in the field, the use of linear arrays, and (for the parabolic trough) lower operating temperature. Finally, development costs for the parabolic trough should be the lowest of all concepts due to the use of nearer term technology, lower temperatures, and system modularity.

8.3 OUTLOOK FOR APPLICATIONS OF LINE FOCUS SYSTEMS

Estimates of the magnitude of the electric utility market open to solar penetration within the next 30 years are problematical. The contractor line focus market penetration studies all indicated that the best solar opportunities are in peak and intermediate load applications. The LFS contractors agreed that it will be difficult for solar plants to compete with nuclear and coal plants for the base load market, even when using optimistic projections for Nth plant solar energy costs. It was further concluded that hybrid solar designs are needed to gain capacity credit and to gain acceptance by the utilities.

In the area of repowering of existing utility power plants, it is improbable that near term line focus technology can be applied to conventional high temperature

(~1000°F) systems because of development problems and poor economics. Repowering the regenerator of conventional plants, however, with low temperature solar collectors not only makes economic sense for fuel displacement, but for some turbine conditions may even provide capacity credit. Field sizes (approximately 10 to 14 percent of the plant rated capacity) are large enough to demonstrate the potential of solar to the utility.

Industrial process heat (IPH) applications appear to provide a larger market for solar systems than the electrical utility applications. This market is concentrated at temperatures below 600°F and, if institutional factors could be resolved, the line focus solar technologies, especially low cost and highly efficient parabolic troughs, are ideally suited for this application.

8.4 NECESSARY LFS TECHNOLOGY DEVELOPMENTS

The performance of all three line focus configurations studied herein strongly depends on the development of stable low emissivity selective surface coatings. This appears to be the basic need of the line focus community.

In addition, each configuration has its own specific problems. The BDM design requires the successful development of the large aperture glass reflected collector. The GA design requires the development of a low cost factory assembled collector with the performance characteristics noted in the study. The SRI receiver technology has not been demonstrated at the prototype level, and receiver loss estimates must be verified.

8.5 POTENTIAL AREAS FOR FURTHER WORK

In line with the comments and points made in the preceding paragraphs, potential areas for further line focus work include the following:

- A study of the low temperature parabolic trough system in combination with current state-of-the-art low temperature steam cycles. The design should address solar/fossil hybrid capability to match the requirements of the utilities.
- A study of selected repowering designs for utility applications. Of particular interest is the repowering of conventional plant regenerators, preheaters and evaporators with low temperature parabolic troughs.
- A study of the application of the low temperature parabolic trough collector to IPH applications. The application of similar collectors and receivers to both electrical and IPH applications can reduce costs by increasing production levels.
- Construction and evaluation of a prototype of the T-2100 21 ft aperture parabolic trough collector as proposed in the BDM study.
- Further development of the lightweight concrete fiber reinforced structure identified in the SRI study for application not only to the single axis heliostat but to other collectors such as parabolic troughs and two axis heliostats.

REFERENCES

1. "Conceptual Design and Analysis of a 100 MWe Line Focus Solar Power Plant," BDM Final Review Briefing, September 1979.
2. "Line Focus Solar Central Power Systems, Phase I," General Atomic Final Review Briefing, September 1979.
3. "High Temperature Line Focus Solar Thermal Electric Central Power Systems," Final Review Briefing, SRI International, September 1979.
4. "Review of BDM Line Focus Power System," Aerospace Memorandum to DOE/SAN, February 1979.
5. "Comments on GA Line Focus Power System," Aerospace Memorandum to DOE/SAN, February 1979.
6. "Comments on the SRI Line Focus Power System," Aerospace Memorandum to DOE/SAN, March 1979.
7. "Line Focus Solar Thermal Central Receiver Research Study," FMC Corporation Final Report (Draft) (Contract EY-76-C-03-1246), February 1979.
8. Coggi, J.V., "High Temperature Line Focus Central Receiver System Cost and Performance Objectives," Aerospace Report No. ATR-78(7773-03)-1, November 1978.
9. Coggi, J.V., "Fixed Mirror Line Focus Central Power System Cost and Performance Objectives," Aerospace Report No. ATR-78(7773-03)-2, December 1978.
10. Coggi, J.V., "Parabolic Trough Line Focus Central Receiver System Cost and Performance Objectives," Aerospace Report No. ATR-78(7773-03)-3, December 1978.
11. "Conceptual Design of Advanced Central Receiver Power System, Phase I," Martin-Marietta Corporation Final Report (Contract EG-77-C-03-1724), September 1978.
12. "Comparison of Collection Technologies for Large Power Systems - Thermal and Electric," Sandia Livermore Presentation to DOE/SAN, September 1979.
13. Lord, N., I. Curto, and S. True, "Solar Thermal Repowering - Utility/Industry Market Potential in the Southwest," MITRE Report No. MTR-7919, The Mitre Corporation, McLean, Virginia, May 1978.
14. "Technical and Economic Assessment of Solar Hybrid Repowering," Public Service Company of New Mexico Study, Final Report SAN/1608-4-1, September 1978.

15. "Survey of Applications of Solar Thermal Energy Systems to Industrial Process Heat," Battelle Laboratories, January 1977.
16. Personal Communication, Sandia Livermore, January 1979.

APPENDIX A

LINE FOCUS SOLAR CENTRAL POWER SYSTEM PERFORMANCE SPECIFICATION

The following specification was used as a guide and control document by the three LFS Study Contractors in their conceptual designs of 100 MWe solar electric plants. Section 1.2, Description, is included in three versions each separately keyed to each Contractor's specific approach. The remainder of the document is applicable to all configurations.

1. GENERAL (GENERAL ATOMIC ONLY)

1.1 SCOPE

This specification defines the design requirements, subsystem characteristics, and environmental requirements for the Line Focus Solar Central Power System.

1.2 DESCRIPTION

1.2.1 Collector Subsystem

The collector subsystem (CS) is composed of an array of fixed, linear focusing concentrators and supporting foundations. Each concentrator row in the array reflects solar radiation onto a movable heat receiver in a manner which satisfies the receiver subsystem incident heat flux requirements.

1.2.1.1 Interfaces

The concentrator interfaces mechanically and optically with the heat receiver subsystem.

1.2.2 Receiver Subsystem

The receiver subsystem (RS) provides the means for transferring the incident radiant flux energy from the CS into a suitable working fluid, and consists of linear heat receiver assemblies (i.e., an assembly having a length much greater than the cross sectional dimensions) which are movable and positioned in the focal zone of the concentrator row. The RS also includes the supporting power and control elements which interact with the master control subsystem; the superstructure and drive hardware for supporting and positioning each receiver; control valves, risers and downcomers; heat tracing (where applicable); and control systems necessary to regulate the fluid flow, temperature, and pressure for safe and efficient operation, startup, shutdown and standby.

1.2.2.1 Interfaces

The heat receiver subsystem shall respond to control signals from the master control subsystem. The mechanical and fluid interface with the heat transport subsystem shall be on the heat receiver side of the shutoff valves. The heat receiver subsystem, including the heat receivers, superstructures, and drive components, shall interface mechanically and optically with the concentrators.

1.2.3 Heat Transport Subsystem

The heat transport subsystem (HTS) is the means of transporting heat from the RS to the energy storage and electrical power generation subsystems for subsequent generation of electricity. It includes the receiver bypass (isolation) valves, inert gas blanketing, heat transport fluid purge provisions for emptying the heat receivers and downcomers (where applicable), fluid piping, thermal insulation, heat tracing (where applicable), piping supports, valves, fluid pumps, motors, motor and valve controls,

fluid conditioning and makeup provisions (where applicable), steam generator and reheater (where applicable).

1.2.3.1 Interfaces

The HTS shall respond to control signals from the master control subsystem. Mechanical and fluid interfaces with the RS and energy storage systems shall be on the receiver and storage side of the shutoff valves.

1.2.5 Electrical Power Generating Subsystem

The electrical power generating subsystem (EPGS) provides the means for converting the thermal output of the working fluid from the RS and the ESS into electric power. The output from the EPGS will be regulated for integration into existing electrical power system networks. It includes the steam turbine and electric generating equipment, boiler feedwater equipment, heat rejection equipment, and power generating subsystem controls.

1.2.5.1 Interfaces

The EPGS mechanical interface with the HTS will be between the steam generator (and reheater where applicable) and the steam isolation valves. The EPGS shall interface with the utility grid.

1.2.6 Master Control Subsystem

The master control subsystem (MCS) will be used to sense, detect, monitor and control all system and subsystem parameters necessary to ensure safe and proper operation of the LFS.

1.2.6.1 Interfaces

The MCS shall interface with the individual subsystem controllers of the receiver, heat transport, energy storage, and electric power generation subsystems.

1.2.7 Plant Support Subsystem

Various plant support subsystems will be required, including power, water, compressed air, and other auxiliaries.

1. GENERAL (SRI ONLY)

1.1 SCOPE

This specification defines the design requirements, subsystem characteristics, and environmental requirements for the High Temperature Line Focus (HTLF) Solar Power System.

1.2 DESCRIPTION

1.2.1 Collector Subsystem

The collector subsystem (CS) is composed of an array of linear focusing heliostats and supporting power and control elements which interact with the master control subsystem. The heliostat array reflects solar radiation onto linear receivers in a manner which satisfies the receiver subsystem incident heat flux requirements. The basic heliostat design will have a single axis drive mechanism which can accommodate path length changes of the reflected solar energy by tracking the sun's motion so as to maintain the focal zone on the receiver. The focal length may be varied during the day. The CS interfaces with the master control subsystem at the drive mechanism motor terminals.

1.2.2 Receiver Subsystem

The receiver subsystem (RS) consists of linear receivers (i.e., a receiver having a length much greater than the cross sectional dimensions) which are located in the focal zone of the heliostats in the collector field. The RS also includes pumps, bypass valves, risers and downcomers (where applicable), heat exchangers; and control systems necessary to regulate the fluid flow, temperature, and pressure for safe and efficient operation, startup, shutdown, and standby of the receiver subsystem. The RS interfaces through the riser and downcomer to the heat transport subsystem at flanges at the top of the towers.

1.2.3 Heat Transport Subsystem

The heat transport subsystem (HTS) is the means of transporting heat from the receiver to the energy storage and electrical power generation subsystems. The HTS interfaces with the storage subsystem at the base of the storage tank and with the EPGS at the entrance point to the EPGS building.

1.2.4 Energy Storage Subsystem

This subsystem provides the means for storing the energy which is available from the receiver. Sensible heat storage will be by oil and rock, unless some other technique peculiar to the system demonstrates special advantage in terms of overall electrical generating costs.

1.2.5 Electrical Power Generating Subsystem

The electrical power generating subsystem (EPGS) shall provide the means for converting the thermal output of the working fluid from the receiver and the energy

storage subsystem into electric power. The output from the EPGS shall be regulated for integration into existing electrical power system networks.

1.2.6 Master Control Subsystem

The master control subsystem shall be used to sense, detect, monitor and control all system and subsystem parameters necessary to ensure safe and proper operation of the HTLP large Solar Power System.

1.2.7 Plant Support Subsystem

This includes plant subsystems such as power, water, compressed air, and other auxiliaries.

1. GENERAL (BDM ONLY)

1.1 SCOPE

This specification defines the design requirements, subsystem characteristics, and environmental requirements for the Line Focus Solar Central Power System.

1.2 DESCRIPTION

1.2.1 Collector Subsystem (CS)

The collector subsystem consists of an array of linear parabolic troughs (LPT) which focus sunlight onto the receiver tube subassembly. The CS consists of all attached mounting, tracking, control, and power equipment. The CS will track in one axis with a focal image which is fixed with respect to the LPT aperture geometry.

1.2.1.1 Interfaces

The collector system interfaces with the mounting platform, the receiver tube subassembly (RTS) and the master control subsystem (MCS). The interface between the CS and the RTS includes a structural interface where "mounts" position the receiver tube subassembly in the focal region of the CS. The second interface between the CS and the RTS involves the focusing of the insolation. The light passing through the aperture of the parabolic trough is focused onto the receiver tube subassembly. The collector system is also interfaced with the master control subsystem. This interface involves a tracking mechanism which provides status data to the control unit and allows an override control capability to the MCS.

1.2.2 Receiver Tube Subassembly (RTS)

The receiver tube subassembly (RTS) is a linear, cylindrical apparatus assembly located at the focal region of the LPT. The RTS consists of a metallic pipe to which is affixed a selective surface exterior coating. Heat transport fluid is continually passed through the receiver pipe. A glass annulus encapsulates the entire assembly.

1.2.2.1 Interfaces

The receiver subassembly has major interfaces with the CS, the heat transport subsystem (HTS), and the MCS. The interfaces with the CS include the structural mounting mechanism and the insolation interface as described under Section 1.2.1. The RTS is coupled with the HTS through a piping connection at the end of each collector row. The piping which carries the heated fluid away from the RTS, or the low temperature inlet fluid to the RTS, is part of the heat transport subsystem. The RTS is coupled with the MCS through temperature, pressure, and fluid flow sensors which allow the MCS to control the fluid flow rate and provide override controls for system safety.

1.2.3 Heat Transport Subsystem (HTS)

The heat transport subsystem (HTS) provides the transport of thermal energy from the CS/RTS to the thermal energy storage subsystem (ESS) and the field boiler/heat exchangers, and from the ESS to the boilers. The HTS includes all plumbing, circulation pumps, insulation, and capacitance tanks.

1.2.3.1 Interfaces

The heat transport subsystem interfaces with the RTS, the energy storage subsystem, the electrical power generating subsystem (EPGS), and the MCS. The HTS interface with the RTS is the pipe coupling described in Section 1.2.2. Another key interface occurs at the EPGS heat exchanger where the thermal fluid transfers energy to form either saturated or superheated steam depending on the specific design of the system. The HTS has several temperature and pressure sensors which provide monitoring capability and override control of fluid flow via the MCS.

1.2.4 Energy Storage Subsystem (ESS)

The energy storage subsystem (ESS) provides a means for sensible heat storage of the thermal energy provided by the CS. The ESS may be centralized or distributed and consists of the tank structure, thermal fluid, and solid thermal energy storage media.

1.2.4.1 Interfaces

The energy storage subsystem is interfaced with the HTS via the piping which provides charging/discharging capabilities from the CS/RTS through the HTS as described in Section 1.2.3. The ESS is interfaced with the MCS through temperature and fluid flow sensors which allow control of the charge and discharge of the energy storage subsystem.

1.2.5 Electrical Power Generating Subsystem (EPGS)

The electrical power generating subsystem converts the thermal output of the CS, transported via the HTS, into electrical power. The EPGS includes the boilers, steam transport, drum, superheater, steam turbine apparatus, and the heat rejection system. The output of the EPGS will be regulated for integration into existing electrical power system networks.

1.2.5.1 Interfaces

The EPGS is interfaced with the HTS via the steam boiler systems as described in Section 1.2.3. The EPGS has an interface with the MCS which monitors and controls the steam conditions and output power level.

1.2.6 Master Control Subsystem

The master control subsystem senses, detects, monitors, and controls all system and subsystem parameters necessary to ensure safe and proper operation of the Line Focus Solar Central Power System.

1.2.6.1 Interfaces

The MCS interfaces with all other major subsystems in the Line Focus Power Plant, as previously described.

1.2.7 Support Equipment and Facilities

Support equipment and facilities include any building, structure, apparatus, or power supply required for normal or emergency system operation and not specifically part of previously described subsystems.

2. DOCUMENTS

The following documents, of the issue in effect on the date of the contract award, form a part of this specification to the extent specified herein. Although the conceptual design effort required of the contractor is not expected to attain a level of detail commensurate with these documents, they are referenced herein to provide guidance in design approach, engineering judgment and cost analysis. To this extent, the system design shall be consistent with the intent of these representative codes.

2.1 CODES AND STANDARDS

OSHA Regulations

OSHA Title 29, Part 1910 - Occupational Safety and Health Standards

ASME Boiler and Pressure Vessel Code

Section I - Power Boilers

Section II - Materials Specifications

Section V - Nondestructive Examination

Section VIII - Unfired Pressure Vessels

Section IX - Welding and Brazing Qualifications

ANSI B31.1-1977 Power Piping

Uniform Building Code - 1976 Edition by International Conference of Building Officials

Institute of Electrical and Electronic Engineers (IEEE) Codes, as applicable

National Fire Protection Association (NFPA) National Fire Codes - 1975

Human Engineering Design Criteria

MIL-STD - 810C

MIL-STD - 1472

Design, Construction and Fabrication Standards

Standards of AISC (Am. Inst. of Steel Constr.)

Standards of ACI (Am. Concrete Institute)

Standards of TEMA (Tub. Exchanger Mfr. Assoc.)

Standard 650 of API (Am. Pet. Inst.) - Welded Steel Tanks for Oil Storage

Environmental Legislation

National Environmental Policy Act (NEPA)

3. REQUIREMENTS

The LFS shall meet the design requirements listed herein.

3.1 ELECTRICAL POWER OUTPUT

The LFS shall produce approximately 100 MWe net when operating solely from insolation and when subjected to the environments specified in Sections 4.1 and 4.2. This rating is the minimum net output of the plant after subtracting all plant auxiliary power requirements.

The plant shall be capable of operation at full rated power for a period of at least four hours when operating solely from insolation every clear day of the year.

The LFS shall provide 420 MWe hours of electrical energy to the utility grid when operating solely from a fully charged energy storage. Net power from storage shall be 70 MWe (minimum).

Power ratings and energy storage capacities other than those specified above should be considered and included if more attractive economic performance results.

3.2 PLANT OPERATING MODES

The plant shall be capable of executing the following operating modes:

1. CS-RS driving the EPGS (TSS is not involved).
2. CS-RS driving the EPGS and charging the TSS (normal solar power operation).
3. CS-RS driving the EPGS while the TSS also discharges to share in driving the EPGS (low solar power operation).
4. CS-RS charging the TSS and TSS discharging to drive the EPGS (intermittent cloudiness).
5. CS-RS charges TSS only (thermal storage charging).
6. TSS discharges to drive the EPGS (extended operation).
7. Overnight shutdown and hold of all plant subsystems (subsystem conditioning).

3.3 ENERGY UTILIZATION

The plant shall be designed to effectively utilize the collected incident sunlight for conversion to electrical energy. This includes steady state operation as well as normal transients such as startup, shutdown, and broken sun operation.

3.4 STORAGE SUBSYSTEM

3.4.1 General

The LFS ESS shall be designed to maximize the economic and safe recovery of useful energy from storage and to minimize energy storage losses. Specific size, shape and configuration constraints will be governed by minimizing the cost of electricity and by designing the power plant layout to facilitate efficient and safe operation and maintenance. The ESS shall be designed to provide safe and reasonable access for proper inspection, maintenance and repair of the structure, fluid lines, utilities, instrumentation and controls, etc. It shall accept and execute commands from the master control subsystem during normal, transient, and emergency operations.

3.4.2 Charging Rate

The storage subsystem charging rate must be sufficient to ensure compatibility with all the plant operating modes and to ensure effective solar utilization.

3.5 COLLECTOR/CONCENTRATOR SUBSYSTEM

3.5.1 Control

The concentrators may be equipped with control systems which employ sensors and drive mechanisms to direct the reflected rays of the sun onto the receiver, as well as to provide auxiliary functions for other methods of operational and non-operational positioning.

3.5.2 Interface

The concentrators shall respond to control signals from the master control subsystem.

3.5.3 Field Optimization

The field optimization will consider shading, blocking and other collector/concentrator position losses and trade them off with heliostat/concentrator costs, land costs, cabling costs, and piping losses to effect an economic minimum cost per deliverable kilowatt hour. Spacing between collector/concentrator modules must permit access by service vehicles, utility lines, and ground maintenance personnel.

3.5.4 Heliostat/Concentrator

Heliostat/concentrator design shall be based on performance, cost, manufacturing, operations, maintenance, and servicing constraints, pointing accuracy requirements; and structural requirements, including wind loading. Heliostat design should provide for stored or safe position for use at night, during periodic maintenance and during adverse weather conditions.

3.5.5 Special Environmental Consideration

The heliostats/concentrators shall withstand winds at the periphery of the collector field as specified in Section 4.2. If it is determined that wind loading on interior heliostats/concentrators is significantly altered by peripheral concentrators, this factor should be considered. Adequate protection shall be provided against heliostat degradation in the saltation layer (the boundary layer above the ground within which blowing particles, such as sand, are concentrated), and against exposure to humidity, temperature transients and other environmental effects specified in Section 4.0.

3.6 RECEIVER SUBSYSTEM

3.6.1 Modes of Operation

The receiver subsystem shall provide a means of transferring the incident radiant flux energy from the collector/concentrator subsystem into a suitable working fluid to facilitate the operation of the LFS in any or all of the operating modes defined in Section 3.1.2.

3.6.2 Control

Sensing elements in the receiver subsystem shall be devised to provide the master control subsystem the information necessary to accomplish efficient and safe monitoring and control of the receiver subsystem. The receiver subsystem shall respond to control signals from the master control subsystem. Means must be provided to protect the heat receivers from over temperatures and system malfunction.

3.6.3 General

For concepts utilizing a tower mounted receiver, the tower shall be designed to provide access for maintenance and inspection of the structure, receiver, working fluid, instruments and controls, power conversion equipment that may be located on the tower, utilities, etc. For concepts having a moving receiver, appropriate positioning for necessary access shall be provided. Consideration shall be given to ease of maintenance. Adequate provisions shall be made to ensure crew safety at all times for required operations, inspection, maintenance and repair. The receiver design shall be consistent with the intent of appropriate ASME boiler codes.

3.7 HEAT TRANSPORT SUBSYSTEM

3.7.1 General

The heat transport subsystem shall provide the most cost effective means of transporting heat from the receiver to the energy storage and electrical power generation subsystems.

3.7.2 Working Fluid

The working fluid for the heat transport subsystem shall be selected on the basis of performance, total system cost, fluid handling requirements, and component development requirements.

3.7.3 Control

The heat transport subsystem shall respond to control signals from the master control subsystem.

3.8 ELECTRICAL POWER GENERATING SUBSYSTEM

3.8.1 General

The EPGS shall provide the means for transforming the thermal energy of the heat transport subsystem into electric power. The output from the EPGS shall be regulated for integration into existing electrical power system networks.

3.8.2 Power Cycle

The conventional steam cycle will be used, with the particular cycle features being selected on the basis of performance, total system cost, and component development requirements.

3.8.3 Control

The EPGS shall accept and execute control commands from the master control subsystem during normal, transient and emergency operating conditions. Specific size, shape, and configuration constraints shall be governed by the needs for minimizing cost of electricity, designing the plant layout to facilitate efficient and safe operation and maintenance, minimizing the effects of thermal shock on the turbine power loop, and providing for safe response to variations in the receiver working fluid outlet conditions.

3.9 MASTER CONTROL SUBSYSTEM.

The master control subsystem (MCS) will supply all required operational and safety controls and will provide state monitoring of all subsystems. The primary requirements imposed upon the MCS are simplicity, reliability, and cost effectiveness of both design and operation. The MCS shall be designed using standard control practices and simple, well defined interfaces between the MCS and the other subsystem controls. Primary operation shall be automatic with operator override capability.

Reliability shall be assured by use of proven designs and elimination of single point failures through redundant elements whenever it is cost effective to do so. Failure of the MCS shall not prevent manual operation of the plant.

The MCS shall contain independent control within each plant subsystem with the coordination of control of the subsystem provided by the central MCS.

3.10 HEAT REJECTION

The LPS must be equipped with wet cooling type of heat rejection.

3.11 LIFETIME

The system shall be designed for a 30 year operating life.

3.12 PLANT AVAILABILITY AND RELIABILITY

The system shall be designed for 90 percent plant availability based on reliability and maintainability exclusive of insolation conditions. Consideration shall be given in the design to attainment of high reliability by providing design and operating margins and utilizing sound engineering design practices.

3.13 MAINTAINABILITY

3.13.1 Maintenance Locations

The entire plant shall be so designed that potential maintenance locations can be easily reached and components such as electronic units, motors, drives, fittings, sensors, etc., readily replaced.

3.13.2 Equipment Replacement

Elements subject to wear and damage, such as supporting wheels, gears, etc., should be easily serviced or replaced.

3.13.3 Personnel

Personnel required to maintain the plant needing special skills other than those currently employed by the utilities should be identified.

3.14 PLANT OPERATION

Manual operational requirements for daily plant operation should be identified. Special skills required for an operator should also be identified.

4. ENVIRONMENTAL CONDITIONS

4.1 BASELINE DESIGN ENVIRONMENT

4.1.1 Reference Site

Barstow, California. Site specific information shall be used as required.

4.1.2 Insolation

The annual and daily insolation variation is given in Figure A-1.

Figure A-1. Direct Solar Insolation-1976-Barstow, California

4.1.3 Dynamic Performance

The maximum rate of change of incident flux shall be assumed as that which would result from the passage of an opaque cloud across an otherwise clear sky where the sharp leading or trailing edges of the shadow move across the concentrator field at a velocity of 20 m/sec (45 mph).

4.1.4 Wind Speed

3.5 m/sec (8 mph) at a reference height of 10 m (30 ft).

4.1.5 Temperature

Wet bulb - 23°C (74°F)

Dry bulb - 28°C (82.6°F)

4.2 OPERATING ENVIRONMENTS

The system shall be capable of operating in and surviving appropriate combinations of the environments specified below:

4.2.1 Insolation

The plant shall remain operational with insolation values to 1000 W/m².

4.2.2 Temperature

The plant shall be able to operate in the ambient air temperature range from -30°C (-23°F) to +50°C (+121°F).

4.2.3 Wind

The wind speed specifications at a reference height of 10 m (30 ft) shall be:

<u>Speed, m/s</u>	<u>Frequency, percent</u>
0 - 2	29
2 - 4	21
4 - 6	19
6 - 8	14
8 - 10	8
10 - 12	5
12 - 15	3
14	Less than 1

Operational performance specifications shall be met for the most adverse probable combination of wind and temperature conditions which are consistent with minimizing the overall cost of electricity. Maximum operational wind speed shall be selected to be consistent with minimization of the overall cost of electricity

production. The wind velocity profile varies exponentially with height to the 0.15 power, where the reference height is taken as 10 m (30 ft), and shall be determined according to the model shown below for calculation of wind speed as a function of receiver elevation.

$$v_H = v_1 \left(\frac{H}{H_1} \right)^C$$

where:

v_H = mean wind velocity at height H

v_1 = reference wind velocity

H_1 = reference height (assume 10 m)

$C = 0.15$

4.3 SURVIVAL ENVIRONMENTAL CONDITIONS

The plant shall be designed to survive without damage the conditions specified below. The plant may take measures to protect vulnerable equipment at points beyond the specific operational limits. The plant, however, shall return to operational status after the environment returns to within the operational limits.

4.3.1 Temperature

The plant shall survive maximum ambient dry bulb temperatures of 60°F (140°F) and minimum temperatures of -30°C (-22°F).

4.3.2 Wind

The plant shall survive winds with a maximum speed, including gusts, of 40 m/s (90 mph), without damage.

4.3.3 Wind Rise Rate

A maximum wind rise rate of 0.01 m/s² (1.3 mph/min) shall be used in calculating wind loads during stowage. However, the plant should withstand, without catastrophic failure, a maximum wind of 22 m/s (50 mph) from any direction, in any orientation resulting from unusually rapid wind rise rates, such as severe thunderstorm gust fronts.

4.3.4 Dust Devils

Dust devils with wind speeds up to 18 m/s (40 mph) shall be survived without damage to the plant.

4.3.5 Snow

Survive 5 lb/ft² (240 Pa) of snow at deposition rate of 0.3 m (1 ft) in 24 hours.

4.3.6 Rain

Average annual - 750 mm (30 in.)

Maximum 24-hr rate - 75 mm (3 in.)

4.3.7 Ice

Survive freezing rain and ice deposits in a layer 12.5 mm (0.5 in.) thick.

4.3.8 Hail

	<u>Any Orientation</u>	<u>Stowed</u>
Diameter	20 mm (3/4 in.)	25 mm (1 in.)
Specific Gravity	0.9	0.9
Terminal Velocity	20 m/s (65 fps)	23 m/s (75 fps)

4.3.9 Sandstorm Environment

The plant shall survive after being exposed to blowing dust comparable to the conditions described by Method 510 of MIL-STD 810 BC.

4.3.10 Seismic Design Criteria

All structures shall be designed in accordance with the provisions of the Uniform Building Code, 1976 Edition, Section 2312, for Seismic Zone 3 as defined therein. In addition, all structures shall be designed to resist the concurrent application of horizontal and vertical base response spectra of the shape given by NRC RG 1.60 for five percent damping with maximum base accelerations of 0.3 g and 0.2 g, respectively.

4.4 LIGHTNING CONSIDERATIONS

4.4.1 Protection

The plant shall be provided with a lightning protection system which is optimized on a cost risk basis.

4.4.2 Direct Hit

Total destruction of a single concentrator and its controller subjected to a direct lightning strike is acceptable.

4.4.3 Adjacent Strike

Damage to a concentrator adjacent to a direct lightning strike must be minimized within appropriate cost risk limits. The central controller and local controllers of concentrators adjacent to a direct lightning strike must be protected or alternate control methods provided to minimize loss of collector subsystem.

APPENDIX B

OPTIMIZATION OF SYSTEM OPERATING TEMPERATURES

B.1 INTRODUCTION

The material in this Appendix was prepared in order to determine LFS performance and cost sensitivities to operating temperatures, and to verify the contractor selected operating points. The simplified analytical model developed accounts for key factors which vary with temperature, including collector and electrical power conversion subsystem efficiencies, thermal storage effectiveness, effects of solar insolation on receiver efficiency, and material costs and limitations.

The optimum operating temperature was developed for each LFS configuration under study. The results are in substantial agreement with the contractor selected operating points, although there are differences in the procedures and rationale used to select these operating points.

B.2 ANALYTICAL PROCEDURES

The analytical procedures used in this study are summarized in Figure B-1. The analysis is designed to calculate the system efficiency and specific cost as a function of coolant outlet temperature and includes the effects of variation in the sun position throughout the day and the year.

The analysis is based on clear day Barstow, California insolation data. Power generation characterizations are modeled for three days of the year--summer and winter solstice and spring equinox. Due to symmetry, only half the day needs to be analyzed. The analysis was not extended over a full year since optimum temperatures did not vary for the three days investigated.

The analysis begins by calculating the normal solar incident energy on the mirrors. The incident energy on the receiver is then calculated using the sun-position-variant optical efficiency. Collector losses are assumed constant with temperature. The receiver output is calculated by subtracting receiver radiation and convective losses from receiver input energy. The magnitude of this thermal loss is essentially constant throughout the day since both the receiver aperture area and temperature are kept constant. Thus, as the insolation drops, efficiency drops.

The overall system efficiency is then calculated using the EPGS and receiver conversion efficiency relations. Finally, the system specific costs (i.e., cost per unit of electrical power out) is calculated using the component costs and the overall efficiency value.

B-3 PERFORMANCE ASSUMPTIONS

Solar insolation data were obtained from The Southern California Edison Company and processed by The Aerospace Corporation (References B-1 and B-2). The data are based on Barstow, California measurements for the best solar insolation day (24 June 1976, representative of summer solstice), worst solar insolation day (21 December 1976), and spring equinox (21 March 1976). See Figure B-2.

Figure B-1. Line Focus Power Plant Analytical Procedures

Figure B-2. Direct Solar Insolation - 1976 - Barstow, California

The performance assumptions are listed in Table B-1. Though the optical data are based on contractor results, the receiver losses and power conversion efficiencies have been developed independently. Receiver losses and power conversion efficiencies are shown in Figures B-3 and B-4.

Table B-2 indicates the initial subsystem capital costs and assumptions used to calculate overall costs. Any costs which are independent of temperature are assumed equal for all systems. The storage cost is referenced to the baseline cost and varies inversely with temperature, based on the assumption that a unit weight of storage material can absorb heat in proportion to the temperature drop across the storage subsystem. Collector and heat transport costs are based on constant specific cost per aperture area, and therefore vary with overall system efficiency.

B.4 ANALYSIS RESULTS ON GENERAL ATOMIC'S LFS CONFIGURATION

The performance optimization is based on the useful output per square meter of aperture area. The analysis begins by determining the normal solar insolation on the mirrors for the three key days of the year. These half-day energy values are 3985 W-hr/m² on December 21, 4962 W-hr/m² on March 21, and 6035 W-hr/m² on June 21. From the instantaneous values are subtracted the optical losses (Table B-1), the receiver losses (Figure B-3), and finally the parasitic and power conversion losses (Figure B-4).

Figure B-5 shows subsystem and total system efficiency variations for one day, with a given receiver coolant temperature. Figure B-6 then shows the integrated efficiencies for March 21, for a range of salt coolant outlet temperature from 850°F to 1150°F. Of special note is the drop in receiver efficiency and increase in EPGS efficiency with increased temperature. As seen in the bottom curve, overall system efficiency has a broad maximum between 950°F and 1050°F. Since similar results were obtained for June 21 and December 21 (Figure B-7), an annual performance calculation was not found necessary.

The results of this system's specific capital cost analysis are shown in Figure B-8. The subsystem cost calculations were based on the assumptions noted in Table B-2. Figure B-8 shows a cost optimum at 1025°F, compared to a GA selected operating temperature of 1055°F.

The optimum temperature was found to be a strong function of the receiver radiative loss. Should that loss increase, optimization of the system cost would lead to a lower operating temperature.

B.5 ANALYSIS RESULTS ON SRI'S LFS CONFIGURATION

The analytical procedures used with the SRI concept are identical to those described in the previous section. SRI receiver losses, as a function of temperature, are shown in Figure B-9. The overall system performance is shown in Figure B-9 for the best and worst day of the year (upper curves). As is seen, system efficiency does not decrease with temperatures as high as 1150°F. This is due to the relatively good receiver efficiency assumed.

Table B-1
LINE FOCUS POWER PLANT LOSS FACTORS

BASILINE OPERATING TEMPERATURE

	BDM	GENERAL ATOMIC	SRI
COSINE FACTOR	VARIABLE (0.83 annual average)	VARIABLE (0.72 annual average)	VARIABLE (0.79 annual average)
REFLECTIVITY, BLOCKING & RECEIVER INTERCEPTION	0.92	0.727	0.85
ATMOSPHERIC (+ window) ABSORPTION	0.91	1.0	0.992
RECEIVER ABSORPTIVITY	0.93	0.86	0.96
RECEIVER RADIATION & CONVECTION	VARIABLE WITH TEMPER- ATURE 0.787 (annual average)	VARIABLE WITH TEMPER- ATURE 0.855 (annual average)	VARIABLE WITH TEMPER- ATURE 0.9 (annual average)
PIPING THERMAL LOSSES	VARIABLE WITH TEMPER- ATURE 0.98 (annual average)	VARIABLE WITH TEMPER- ATURE 0.98 (annual average)	VARIABLE WITH TEMPER- ATURE 0.98 (annual average)
PARASITIC LOSSES	0.85	0.85	0.85
EPGS CONVERSION EFFICIENCY	STEAM TEMPERATURE (°F)		EFFICIENCY
	650		0.31
	750		0.32
	850		0.355
	950		0.39
	1050		0.415

Table B-2
LINE FOCUS POWER PLANT COST COMPARISON
(IN 1978 DOLLARS)

	BDM	GENERAL ATOMIC	SRI
CAPITAL COST (\$/KW)			
LAND, YARDWORK	7	7	7
STRUCTURES, etc.	46	50	39
TURBINE PLANT	170	170	170
ELECTRICAL PLANT	67	67	67
CONCENTRATORS	VARIABLE ⁽¹⁾	VARIABLE ⁽²⁾⁽³⁾	VARIABLE ⁽⁴⁾
RECEIVER(S)	VARIABLE ⁽⁶⁾	VARIABLE ⁽⁶⁾	VARIABLE ⁽⁵⁾
HEAT TRANSPORT	VARIABLE ⁽⁶⁾	VARIABLE ⁽⁶⁾	VARIABLE ⁽⁶⁾
TOWER(S)	NOT APPLICABLE	NOT APPLICABLE	VARIABLE ⁽⁷⁾
THERMAL STORAGE	VARIABLE ⁽⁸⁾	VARIABLE ⁽⁸⁾	VARIABLE ⁽⁸⁾
DISTRIBUTABLES	39	39	39
BALANCE OF PLANT	38	38	36

(1) Based on \$5.16/ft² of aperture area

(2) Collector based on \$6.65/ft² of aperture area

(3) Receiver based on \$5.08/ft² of aperture area

(4) Heliostat based on \$5.16/ft² glass area

(5) Receiver based on \$500/ft of length

(6) Based on \$200/ft of heat transport pipe length

(7) Based on \$132/ft of receiver length

(8) Referenced to \$25/kW-hr at 500°F temperature difference

Figure B-3. Line Focus Receiver Thermal Losses

Figure B-4. Power Conversion Subsystem Efficiency as a Function of Primary Coolant Peak Temperature

Figure B-5. Fixed Mirror System Half-Day Variation in Subsystem Efficiencies

Figure B-6. Fixed Mirror System Performance

Figure B-7. Fixed Mirror System Annual Performance

Figure B-8. GA System Specific Cost

The receiver loss was based on the use of an advanced selective surface coating of extremely low emissivity. If this coating is not available at the time the plant is scheduled to be built, the performance changes dramatically, as is seen in the lowest curve on Figure B-9. The efficiency of this system with a conventional coating is substantially lower than the baseline, and, unlike previous SRI studies, optimizes at temperatures well below 850°F. The results of the SRI system specific capital cost analysis are shown in Figure B-10. The SRI selected design point of 1050°F salt outlet temperature is considered reasonable, taking into account temperature limitations on both the primary coolant system and the electrical power conversion system.

B.6 BDM'S LFS CONFIGURATION ANALYTICAL RESULTS

Below 600°F the parabolic trough analysis is based on the use of single low cost fluid collector field for both the boiler and superheater. At higher peak temperatures, a low temperature field is used for boiling of the condensate and a second higher temperature field is used for superheat and reheat. BDM uses Therminol 55 for the low temperature field and Syltherm 800 for the high temperature field. The high temperature design is further based on the availability of a coating with properties similar to black chrome at temperatures higher than 600°F.

The procedures used for the parabolic trough analysis are similar to those used on the previous systems. Because of the north-south orientation of the troughs, however, an added complication arises due to shading between troughs. For example, at equinox the sun rises at 6:00 am, but the trough does not begin to collect energy until 7:30, thus losing 1512 watt-hr/m² of energy per day.

The thermal losses for the trough as a function of temperature are shown in Figure B-3. These losses are relatively insensitive to temperature because the superheating function takes a small amount of the total energy while the low temperature sections used for boiling provide most of the heat. The overall fluid bulk temperature remains low even with peak outlet temperatures up to 1000°F.

Subsystem and system efficiencies are shown in Figure B-11. The optimum performance temperature selected by this analysis is 950°F, as compared to 600°F selected by BDM.

The cost analysis results are shown in Figure B-12. At temperatures below 600°F, only a single low cost field is used and the specific costs drop rapidly with increasing temperature. This is due to the lower thermal storage cost which results from higher temperature differential across storage. Above 600°F, the dual field design is used and the cost increases due to the higher cost fluid and the second thermal storage tank which is added with the high temperature field. (The analysis was not completed between 600 and 700°F due to more complicated detail in this area caused by the switch to the dual field design.)

As the dual field temperature is increased, the specific cost drops as a result of higher efficiency. It reaches a minimum at 825°F, rather than the 950°F performance maximum, because thermal storage costs increase with temperature due to an increased percentage of the high temperature (high cost) fluid.

Figure B-9. SRI System Performance

Figure B-10. SRI System Specific Cost

Figure B-11. BDM LFS Performance

Figure B-12. Parabolic Trough System Specific Cost Optimization

B.7 CONCLUSIONS

Based on preliminary analysis, the following is concluded relative to optimum operating temperatures in LFS configurations.

1. Performance optimization should be based not only on subsystem variation with temperature but also on the magnitude of incident insolation and the temperature difference across thermal storage.
2. LFS receiver thermal losses are essentially constant and relatively high due to low concentration ratios. At low insolation values, these losses may result in low overall system efficiency or may prevent system operation altogether.
3. The optimum operating temperatures developed by this analysis are:

	<u>Contractor Recommendation (°F)</u>	<u>This Analysis (°F)</u>
GA	10545	975
SRI	1050	1050
BDM	590	825

4. The operating temperature of 975°F calculated in this analysis for the GA system is lower than the contractor values due primarily to the higher radiation losses assumed here. Until the GA receiver coating is better defined, it is felt that a more conservative assumption is appropriate.
5. Assuming availability of low emissivity selective surface coatings, the SRI system optimizes at the highest possible temperatures, limited only by material considerations.
6. The parabolic trough system appears to optimize at a higher temperature and has a broader efficiency peak than values proposed by BDM. Peak temperature, however, will be limited by the stabilized black chrome receiver coating. This limit is now assumed by BDM to be 750°F.

REFERENCES

- B-1 Patapoff, N.W., "The West Associates Solar Resource Evaluation Project - Solar Energy Measurements During 1976," Project Manager, Southern California Edison Company, June 1977.
- B-2 Randall, C.M., "Barstow Insolation and Meteorological Data Base," The Aerospace Corporation Technical Report ATR-78(7695-02)-2, 13 March 1978.

APPENDIX C

PRELIMINARY EVALUATION OF THERMAL STORAGE CONCEPTS FOR SALT COOLED LFS CONFIGURATIONS

C.1 INTRODUCTION

The objective of this preliminary study is to determine the most cost effective means of storing thermal energy for high temperature, salt cooled LFS configurations. The system selection is based on capital and operating costs, performance, technical risk and operational factors.

C.2 STORAGE OPTIONS

Table C-1 presents a matrix of possible salt storage options for storage coupled solar thermal power plants. The table lists the storage combinations considered technically feasible at the capacity and temperature conditions imposed by the system design. Fabrication materials and tank sizing conditions are noted.

Table C-1
SALT THERMAL STORAGE OPTIONS

TSS Option	Remarks
Thermocline Single Tank All Salt	Internal Insulation (24 in. salt internal insulation) Carbon Steel Containment Length to Diameter Ratio Equal to 1.0
Thermocline Single Tank Salt/Taconite	Stainless Steel Containment External Insulation (12 in. calcium silicate) Length to Diameter Ratio Equal to 0.5
Two Tank All Salt	Stainless Steel Hot Tank External Insulation (12 in. calcium silicate) Carbon Steel Cold Tank External Insulation (6 in. calcium silicate) Length to Diameter Ratio Equal to 0.5 (both tanks)

C.3 STUDY ASSUMPTIONS

The nominal size of storage assumed to be required for the power system under study is 420 MWe-hr, i.e., nominally four hours of nighttime operation for a 100 MWe plant. In addition, an 80 MWe-hr of additional storage is assumed to be needed for the plant daily startup and shutdown functions.

In a thermal storage system, a certain amount of stored energy cannot be recovered. To account for this effect, a heat recovery efficiency factor of 96 percent is assumed for the study.

A salt medium freezes at temperatures which are relatively high (several hundred degrees Fahrenheit), introducing serious complications in the use of this material for a solar installation. For this reason, it is assumed here that salt temperature excursions are limited to the 550-1050°F range.

Further thermophysical properties of interest, at an average temperature of 800°F, are:

	<u>SALT</u>	<u>TACONITE</u>
Specific Heat (Btu/lb°F)	0.373	0.23
Density	113	237
Thermal Conductivity (Btu/hr-ft°F)	0.2	--

C.4 SYSTEM OPERATION

Figure C-1 presents the basic characteristics of the candidate thermal storage options. The all salt and salt/taconite thermocline concepts are generally similar and are represented by the same diagram (B). For reference, and comparison of subsystem design and operational characteristics, some basic performance factors and duty cycles have been identified for each concept.

The two tank design requires two tanks of equal size, each rated for the full storage energy requirement. This system also requires an additional hot pump to deliver the hot salt from the storage tank to the steam generators. The thermocline design requires one less pump (but with a higher head requirement) and some flow switching when changing from a charging to discharging mode. The assumption is made that the two tank system has a 15 percent higher total loop pressure drop.

C.5 ENERGY STORAGE COMPARISONS

A parametric analysis was performed comparing (a) the molten salt/taconite thermocline, (b) the all salt thermocline, (c) an all salt single hot, single cold tank design. The thermocline designs were sized for assumed utilizations (U) ranging from 60 to 100 percent, and their performance based on models developed by the Energy Systems Group of Rockwell International. The required volume of thermal storage was calculated using the relation:

$$\text{Volume} = \frac{Q_{MWe} \times \text{HRS} \times 3.412 \times 10^6}{\text{PCE} \times \text{HRE} \times U \times \text{TEMP} \times \rho c_p}$$

where

$Q_{MWe} \times \text{HRS}$	=	required stored energy
PCE	=	power conversion efficiency
HRE	=	heat recovery efficiency
U	=	utilization (percent of stored energy which can be drained effectively from thermocline tank)

TWO TANK STORAGE

THERMOCLINE STORAGE

Figure C-1. System Schematics

TEMP	=	temperature difference
pc_p	=	mass specific heat of storage

A summary of results is indicated in Table C-2. It is seen that there are reduced volume requirements with the higher utilizations for both thermocline systems; however, this is achieved with a severe penalty in the final exit temperature of the salt as the energy is drained. Note that the thermocline system requires an additional tank to drain the heat transport and collector subsystems as well as the storage tank, if that tank has a failure.

C.6 COST ANALYSIS

Table C-3 presents the cost data for the candidate concepts previously identified. These analyses assume draw salt costs of 15¢/lb and taconite costs of 3¢/lb including shipping.

The table includes additional cost items identified in this study as being important in the concept tradeoff. All the thermocline systems require an additional tank to drain the heat transport subsystem and collector fields and to drain the thermocline tank when that tank requires service. The taconite thermocline design contains an additional cost factor for taconite cleanup and preparation prior to commissioning. (This system should also have a cost penalty for purification of taconite particles in the fluid loop; however, the extent of this problem and its associated costs are not known at this time.) Finally, the two tank system requires an additional hot pump.

The cost for a tank is:

$$\text{Cost} = k \times V^{0.8}$$

where V is the tank volume and k depends on the tank material and mode of insulation.

C.7 TSS COST COMPARISONS

Figure C-2 compares the costs for the taconite/salt, all salt thermoclines, and all salt two tank system designs as a function of assumed thermocline extraction efficiency. The all salt thermocline does not become competitive until the utilization is on the order of 65 percent. The breakeven point for the taconite system is at a utilization of 60 percent.

The actual maximum utilization of a thermocline system is presently unknown. At high utilizations the concept has an inherent temperature degradation during discharge which can seriously lower the efficiency of the conversion efficiency.

Thus the theoretical cost savings at higher utilizations might be nullified by the additional design and fabrication expenses of an inlet/outlet manifold system which minimizes mixing and promotes stratification.

Table C-2
TSS SUBSYSTEM CHARACTERISTICS

Characteristic	Salt/Taconite Thermocline			Salt Thermocline		Salt Two Tank
	U = 60%	U = 65%	U = 100%	U = 60%	U = 100%	
Storage Volume (ft ³)	254,093	236,794	153,656	300,363	180,000	—
Hot Tank	—	—	—	—	—	195,000
Cold Tank	—	—	—	—	—	195,000
Salt Weight (lb x 10 ⁶)	11.6	10.7	6.93	33.8	20.3	—
Hot Tank	—	—	—	—	—	22
Cold Tank	—	—	—	—	—	22
Taconite Weight (lb x 10 ⁶)	36.4	33.6	21.83	—	—	—
Tank Material	SS	SS	SS	CS	CS	SS hot tank Carbon steel cold tank
Temperature Drop due to Utilization (°F)	80	100	200	70	200	0
Drain Tank Volume (ft ³)	102,400*	94,300*	61,500*	73,000**	45,000**	—

* Adequate volume to drain thermocline tank.

** Assume 25% redundancy.

Table C-3
TSS COST SUMMARY (\$ Millions)

Cost Elements	Salt/Taconite Thermocline			Salt Thermocline		Two Tank Salt
	U = 60%	U = 65%	U = 100%	U = 60%	U = 100	
Salt Cost (\$/lb)	1.74	1.61	1.04	3.2	3.3	1.44
Taconite (\$/lb)	1.1	1.01	0.63	—	—	—
Construction	2.16	2.03	1.44	1.0	0.8	4.01
Fixed Drain & TSS Drain Tank	1.04	0.97	0.69	0.3	0.27	—
Additional Pump	—	—	—	—	—	.242
Additional Pumping Power	—	—	—	—	—	.45
Taconite Preparation	0.27	0.23	0.16	—	—	—
Purification & Makeup System	TBD	TBD	TBD	TBD	TBD	TBD
Cost Summary	6.07	5.82	3.98	6.3	6.37	6.14

Figure C-2. Thermal Storage System Cost Comparison

C.8 CONCLUSIONS

Based on this preliminary analysis, the advantages and disadvantages of three TSS design options have been developed. They are summarized in Table C-4.

It is concluded that the salt/taconite thermocline design does not offer a significant cost advantage over the all salt thermocline to compensate for the development risk and operational constraints imposed by the taconite, and that this concept should be deemphasized. Though the all salt thermocline design indicates cost advantages over the two tank system at high utilizations, the ability to achieve these utilizations is still unproven. Thus it is likely that the choice between these two designs will be based on important noneconomic factors, including user preference for a given technology.

Table C-4
CONCEPT ADVANTAGES AND DISADVANTAGES

<u>TSS Concept</u>	<u>Advantages</u>	<u>Disadvantages</u>
Salt/taconite Thermocline	<ol style="list-style-type: none"> 1. Cost advantages at utilization greater than 60 percent. 2. Preliminary tests indicate stable salt/taconite combination. 3. Requires only one cold pump. 	<ol style="list-style-type: none"> 1. There is an EPGS and system performance and cost penalty associated with a temperature decay during discharge of the thermocline. 2. Requires drain tank in case of TSS leaks or HTS drain. 3. No experimental data on salt/taconite systems. 4. Development problems associated with inlet and outlet manifolds to prevent loss of stratification. This may be a heavy cost penalty. 5. Long term stability of salt/taconite unknown. 6. Requires 2.3 times the weight of an all salt system which may impose severe foundation problems and costs. 7. Taconite particles in salt will require filters and may deposit on generation equipment resulting in damage. 8. Operationally more complex.
All Salt Thermocline	<ol style="list-style-type: none"> 1. Cost advantages at utilizations greater than 65 percent. 2. Minimum container salt compatibility problems. 3. Requires only one cold pump. 4. Clean system. 5. Cheaper carbon steel container. 6. Common development with another DOE program. 	<ol style="list-style-type: none"> 1. See salt/taconite items 1, 2, 4, 8. 2. Internal insulation is a development item. 3. Performance is questionable since all experimental work has been limited to small size systems. 4. Temperature cycling on tank wall will induce cyclic stresses.
Two Tank Salt System	<ol style="list-style-type: none"> 1. Known technology. 2. Tanks may be used to drain field. 3. Eliminates transients due to cloud cover or load fluctuations. 4. Operationally simpler. 	<ol style="list-style-type: none"> 1. Requires development of high temperature pump. 2. Larger tank required. 3. There may be an initial cost penalty.

APPENDIX D

ANALYSIS OF THE GENERAL ATOMIC FIXED MIRROR SOLAR CONCENTRATOR

D.1 INTRODUCTION

The General Atomic collector is a unique surface that focuses parallel incident light into a sharp line focus regardless of the incident light direction. Theoretically, this nonparabolic surface exhibits no off-axis aberration. The mirror is composed of long, narrow, flat reflecting slats arranged on a reference cylinder. The angles of the slats are fixed so that the focal distance of the array is $2R$, where R is the radius of the cylinder.

Since the line focus always falls on the reference cylinder, the heat receiver can be supported on arms that pivot at the center of the reference cylinder. The solar collector remains stationary as the heat receiver tracks the solar image. This is the concept of the Fixed Mirror Solar Concentrator (FMSC).

The objective of this brief review of the FMSC optics is to ascertain that the collector performance proposed by General Atomic can be achieved within the scheduled availability of the plant. The results of this study verified the General Atomic analysis. The slight loss factor efficiency differences noted in this report were discussed with the contractor and the differences were resolved.

D.2 THEORY OF THE FIXED MIRROR SOLAR CONCENTRATOR

It can be shown that if a mirror is placed on a cylinder at an angle measured along the circumference from the tangent mirror and this mirror makes an angle $\theta/4$ with respect to the tangent slat, parallel rays will be reflected to a line on the cylinder. The labeling of the geometry of the FMSC is shown in Figure D-1.

The FMSC is oriented with its length along the east-west direction and tilted so that the tangent slat is perpendicular to the equatorial plane. This arrangement causes the concentrator to have its greatest efficiency during the equinoxes. A yearly plot of the energy collected tends to be flatter for this reason in comparison to the north-south orientation. Also, tracking of the sun's image requires less movement by the heat receiver and, therefore, less energy expended when the FMSC is in the east-west orientation.

The collector model which was verified has 61 slats with coordinates in inches given by:

$$X(i) = -69.000 + 2.300(i-1) \quad \text{Eq. 1}$$

$$Y(i) = 92.850 [+1 - \cos \theta(i)] \quad \text{Eq. 2}$$

$$\theta(i) = -\text{ARCSIN} [X(i)/92.850] \quad \text{Eq. 3}$$

The angle $\theta(i)$ is the location of the i th slat with respect to the tangent slat and $\rho + \theta(i)$ is the angle with respect to a vertical line. A slat makes an angle $\rho + \theta/4$ with respect to a horizontal line. For the FMSC considered ρ was 35° .

Figure D-1. Slat Mirror Geometry

The aperture of the FMSC is given by

$$A = 2R \sin \theta_{in}/2$$

Eq. 4

where

$$\theta_{in} = 96^\circ$$

and

$$R = 92.850 \text{ in.}$$

The FMSC panel length is 18 ft which gives a collector area of 207 ft². The angle between an individual slat and the sun projected on the north-south vertical plane is $\rho + \theta/4 + \phi$, where ϕ is the sun angle measure with respect to the local longitudinal line (see Figures D-2 and D-3).

D.3 LOSS FACTORS

The heat output of the collector receiver subsystem will be attenuated by various optical thermodynamic loss mechanisms. Associated with each loss mechanism is an efficiency factor η_i which is related to the heat output by

$$Q_{out} = Q_{in} \pi_i \eta_i$$

where

$$\pi_i = \eta_1 \times \eta_2 \times \dots \times \eta_n \quad \text{Eq. 5}$$

The loss factors considered in this study are cosine loss, edge loss, end loss, reflective loss, and shadow losses.

D.3.1 Cosine Loss Factor

The first loss considered in this analysis is attributed to the cosine effect. This loss derives its name from the fact that the projected collector area is proportional to the cosine of the angle between the sun and the tangent slat normal (see Figure D-4). Therefore, the cosine factor is

$$\hat{N}_T \hat{S}_i = -\sin 35^\circ \cos \mu \cos \psi + \cos 35^\circ \sin \psi \quad \text{Eq. 6}$$

The cosine loss is

$$\eta_{cos} = + (1/N) \sum_i \hat{N}_T \hat{S}_i \quad \text{Eq. 7}$$

where N is the number of S_i taken in the sum and the scalar product $N_T S_i$ is defined in equation 6.

To simplify the annual calculation of cosine loss the average value was taken as the average value of the quantity at summer solstice, winter solstice and twice the quantity of the vernal equinox. The number of terms N is therefore equal to 4.

$$\eta_{cos}(\text{March 21}) = 0.734$$

$$\eta_{cos}(\text{Dec 21}) = 0.753$$

$$\eta_{cos}(\text{June 21}) = 0.674$$

These values led to an overall average of

$$\eta_{cos} = 0.724$$

This value differs by about nine percent from the General Atomic overall collector efficiency based on the same three days as taken from their SUNPOW program.

$$\begin{aligned}\text{COSINE FACTOR} &= \hat{N}_T \cdot \hat{S} = \\ &= -\sin 34.90^\circ \cos \mu \cos \phi + \cos 34.90^\circ \sin \phi\end{aligned}$$

$\hat{N}_T$ IS A UNIT VECTOR NORMAL TO THE TANGENT SLAT
 $\hat{S}$ IS IN THE DIRECTION OF THE SUN'S RAYS

Figure D-4. Cosine Losses

D.3.2 Edge Loss

The edge loss is caused by light reflected to an edge on the FMSC and thus not reaching the heat receiver (see Figure D-5 and D-6). It can be seen that the ratio of the slat area blocked by an edge to the entire area of a slat is (Reference D-1).

$$\frac{d}{w} = \frac{\cos^2(\rho + \theta/4) \tan(\theta + \rho) - \tan(\rho + \theta/4) \cos(\phi + \rho + \theta/2)}{\cos(\theta/4) \sin(\phi + \rho + \theta/4)} \quad \text{Eq. 8}$$

The efficiency of a given slat is

$$\eta_{\text{edge}} = (W-d)/W \quad \text{Eq. 9}$$

Figure D-5. Edge Losses

Figure D-6. Edge Geometry

During the equinoxes η_{edge} is nearly equal to 1 and so the effect of edge losses can be neglected. During the solstices, these losses are greatest. At the equinox the average edge loss of 25.899 W/m² corresponds to an efficiency greater than 99 percent. This justifies the neglect of η_{edge} at that time. At summer solstice, the edge loss yields an efficiency of

$$\eta_{\text{edge}} = 0.716$$

At the winter solstice one finds

$$\eta_{\text{edge}} = 0.751$$

The overall average efficiency of edge losses is found to be $\eta_{\text{edge}} = 0.867$

D.3.3 Calculation of Shadow Loss

The shadow of the receiver falls on the reflecting panels and therefore renders the shadowed portion ineffective since it does not collect sunlight (see Figure D-7). The Aerospace assumption is that this efficiency is equal to the difference between the unshaded fraction and the shaded fraction. That is

$$\eta_{\text{SHADW}} = A_{\text{REC}}/A_{\text{COLL}} = 0.967 \quad \text{Eq. 10}$$

Figure D-7. Geometry for Calculating Shadow Loss

The data from SUNPOW gives η_{SHADO} equal to 0.966, 0.974 and 0.970 for equinox, summer and winter solstice respectively. Averaged over a year the General Atomic value is

$$\eta_{\text{SHADO}} = 0.969$$

which differs from the Aerospace number by only 0.2 percent.

D.3.4 Calculation of End Losses

For any time other than high noon a certain part of the rays collected by the FMSC will be reflected beyond the end of the receiver. The amount of energy lost is proportional to the length of unilluminated receiver X. It is easily seen that

$$X = d \cot \Omega \quad \text{Eq. 11}$$

where d is the average distance between the mirrors and the receiver, and Ω , the solar angle projected in the east-west vertical plane, is defined by equation 10.

The position of the ith mirror is given by equations 1 and 2 (x(i), y(i)). During the equinoxes the position of the receiver with respect to the tangent slat is

$$x_r = 0$$

$$Y_r = 2R \cdot 14.024 \text{ ft}$$

where 7.737 ft, the value of R from the SUNPOW program has been used for the radius of the reference cylinder. The distance d(i) between receiver and the ith mirror is given by:

$$d(i) = [(X_r - S(i))^2 + (Y_r - Y(i))^2]^{1/2} \quad \text{Eq. 12}$$

The average projection of this distance along the line from the tangent slat to the receiver for the 61 mirrors is the effective distance

$$d = \sum_{i=1}^{61} d(i) \cos \alpha(i) / 61 \quad \text{Eq. 13}$$

$$\text{where } \alpha(i) = \text{ARC Sin } \frac{R \sin \alpha(i)}{d(i)}$$

A computer program was developed to calculate d. Once d is obtained it is substituted into equation 11 to get X.

The efficiency is the ratio of the illuminated receiver length to the length of the receiver. Therefore,

$$\eta_{\text{end}} = (1 - x)/l \quad \text{Eq. 14}$$

$$= 1 - d/\cot \Omega l/l \quad \text{Eq. 15}$$

Since $\frac{\partial \eta_{\text{end}}}{\partial l} = 0$

The efficiency can be increased by increasing the length l of the receiver/collector system. This is accomplished by placing the collectors end to end extending the receiver along the entire length of the collectors.

In this tandem arrangement an effective length of 900 ft is obtained for columns of 25 36 ft collectors.

It was found that $d = 160.69$ in.

Therefore, equation 15 becomes for a 900 ft effective length receiver/collector

$$\eta_{\text{end}} = 1 - 0.01488/\cot \Omega l \quad \text{Eq. 15}$$

The average over the equinox from 7:00 am to 5:00 pm is

$$\eta_{\text{end}} = 0.976$$

This value compares well with the General Atomic derived value of 0.981.

REFERENCES

- D-1 J.L. Russell, Jr., E.P. DePlomb and R.K. Bansal, "Principles of the Fixed Minor Solar Concentrator," General Atomic Report GS-A12901, February 1977.

APPENDIX E

EVALUATION OF THE T-2100 PARABOLIC TROUGH COLLECTOR

1.0 INTRODUCTION

The primary purpose of this Appendix is to assess the validity of performance predictions for the BDM parabolic solar collector design. To accomplish this objective, this study presents an independent analysis of the parabolic collector concept and compares this analysis with the work performed by BDM. Wherever possible, an attempt was made to validate the models developed during the analyses by comparing their performance predictions with actual test data. While it is not the intent of this report to provide highly detailed and comprehensive models for a parabolic solar collector, enough information is given to identify the significant system level relationships between system variables. Parameterization of these equations would provide sufficient detail for system design studies.

2.0 ANALYSIS

2.1 PARABOLIC SOLAR COLLECTOR DESCRIPTION

The baseline collector system being analyzed is shown in Figure E-1. The concentrator trough is manufactured by Solar Kinetics, Inc. of Dallas, Texas, and is designated the T-2100. It has an aperture of 21 feet and a 90° rim angle (a 90° rim angle requires the aperture plane to contain the focal line). Each trough section is 20 feet long and supported by two steel pylons, one at each end. The tracking drive mechanism is mounted on the pylons. Up to 10 trough sections may be joined into a single tracking unit.

The operation of a parabolic trough collector is best understood by referring to Figure E-2. The figure illustrates the path of a typical plane of insolation rays as they intercept principal collector components. The illustration assumes the collector is a sun-tracking mode of operation; therefore, all incident rays are parallel to the collector's plane of symmetry; i.e., the plane formed by the intersection of the aperture and the focal line. The ray trace makes it intuitively clear that all rays reflected from the concentrator surface will pass through the focal line, irregardless of the angle of incidence (of course in the limiting case characterized by an angle of incidence of 90°, the focal line would never be intersected).

2.2 PARABOLIC SOLAR COLLECTOR PERFORMANCE MODEL

The purpose of a solar collector is the collection and conversion of solar energy to some form of "useful" energy. In this case, the "useful" energy is an increase in the internal energy of a working fluid. A collector's efficiency is a measure of how adequately this process is performed. For the purpose of this report, collector efficiency is defined as:

$$\eta_{COL} = \frac{E_f}{TA} \quad (1)$$

Figure E-1. T-2100 Concentrating Solar Collector Array

Figure E-2. Parabolic-Cylindrical Solar Collector Operation

where

E_f = Energy absorbed by working fluid (W)

I = Direct normal insolation (W/m^2)

A = Collector aperture area (m^2)

Defining and modeling (or referencing models for) all of the system energy losses that reduce the incident energy, IA , to the absorbed energy, Q , is one of the principal intents of this study.

To begin, the geometry of an ideal solar collector is established. The resulting geometric model describes the travel of the rays of insolation as they are redirected to the receiver tube. This model provides the basic framework for the further analysis of solar collector performance (Figure E-3). The analysis then continued by classifying collector energy losses into the following four major areas and developing efficiencies to quantify these losses:

Figure E-3. Collector Performance Model Schematic

1. Losses incurred before insolation penetrates the collector aperture (Shadowing Efficiency)
2. Losses incurred due to the orientation of the aperture (Apparent Aperture Efficiency)
3. Losses incurred as insolation travels between the collector aperture and the focal line (Intercept Efficiency and Optical Efficiency)
4. Losses due to heat loss (Thermal Efficiency)

2.2.1 Collector Geometry

Figures E-4 and E-5 display the geometrical parameters which describe the orientation of a parabolic solar collector tracking the sun. Figure E-4 illustrates the three angles which orient a collector with respect to a (south, east, up) reference frame, while Figure E-5 displays the geometry defining the sun's elevation and azimuth angles, and the solar incidence angle. It is this last angle, the solar incidence angle, which is of major importance to collector performance.

An extension of the results presented in Reference E-1 produces the following expression for a parabolic collector tracking the sun:

$$\sin \theta = -\sin \delta \sin \epsilon + \cos \phi \cos \delta \cos \alpha \cos \epsilon + \sin \phi \cos \delta \sin \alpha \cos \epsilon \quad (2)$$

where, as defined in Figures E-4 and E-5,

- θ = Solar incidence angle
- α = Solar azimuth angle
- ϵ = Solar elevation angle
- δ = Collector tilt angle
- ϕ = Collector field orientation angle

The solar elevation and azimuth angles are given by

$$\epsilon = \sin^{-1} (\cosh \cos \delta \cos \gamma + \sinh \sin \gamma)$$

and $\alpha = \sin^{-1} (\sinh \cos \delta / \cos \epsilon)$

where ϵ = Solar elevation angle

α = Solar azimuth angle

$$h = \frac{360}{24} \text{ HR, degrees}$$

Figure E-4. Collector Orientation Relative to Earth

$\underline{i}$, $\underline{j}$, $\underline{k}$ unit vectors point in South, East, Up directions, respectively

$\underline{f}$, $\underline{n}$, $\underline{z}$ unit vectors rotate with collector aperture

$\underline{f}$ is parallel with focal line

$\underline{n}$ is parallel with aperture normal

$\underline{z}$ is orthogonal to $\underline{f}$ and $\underline{n}$

ϕ = collector field orientation angle, zero implies N/S

δ = collector tilt angle, zero implies horizontal focal line

λ = tracking angle

Figure E-5. Collector Orientation Relative to Sun

$\underline{i}, \underline{j}, \underline{k}$ unit vectors point in South, East, Up directions, respectively

$\underline{f}, \underline{n}, \underline{z}$ unit vectors rotate with collector aperture

$\underline{f}$ is parallel with focal line

$\underline{n}$ is parallel with aperture normal

$\underline{z}$ is orthogonal to $\underline{f}$ and $\underline{n}$

$\underline{s}$ unit vector points toward sun

θ = solar incidence angle

α = solar azimuth angle

ϕ = solar elevation angle

HR = Hours measured from solar noon

$$d = \sin^{-1} \left\{ \left[\sin 23.5^\circ \right] \left[\cos \left(\frac{360}{365.25} DY \right)^\circ \right] \right\}$$

DY = Day of year measured from summer solstice

γ = North latitude

An expression for the tracking angle, can also be derived and is given by

$$\cot \lambda = \frac{-\sin \phi \cos \alpha \cos \epsilon + \cos \phi \sin \alpha \cos \epsilon}{\cos \delta \sin \epsilon + \sin \delta \cos \phi \cos \alpha \cos \epsilon + \sin \delta \sin \phi \sin \alpha \cos \epsilon} \quad (3)$$

2.2.2 Shadowing Efficiency

Collector energy losses incurred before insolation penetrates the collector aperture can more simply be called shading losses. The major contributors to insolation occlusion are collector pylons and tracking hardware, the receiver tube and its supports, and collectors in adjacent rows. For all practical purposes, shading due to the receiver tube itself is virtually negligible. The reason for this is more clearly explained by referring to Figure E-6. Because the absorptivity of the receiver tube selective surface remains relatively constant with the angles of incidence up to 60° , only about 13 percent of a T-2100 collector's incident insolation intercepted by a receiver tube fails to be absorbed. (Due to the curvature of the receiver tube, 13 percent of the intercepted insolation strikes the tube at an angle of incidence greater than 60° .) On a daily basis, this amounts to less than a 0.3 percent reduction in the maximum amount of insolation the collector aperture can intercept.

Occlusion due to the other contributors listed above can, on the other hand, account for up to a two percent average energy loss per day. This loss value assumes the baseline collector array shown in Figure E-1 oriented in the N/S direction ($\phi = 0$).

A relationship which gives the percent of daily insolation loss due to shading by adjacent collector rows can be derived by considering the geometric model shown in Figure E-7. The ratio of unshaded aperture area to total aperture area, η_s , is found to be

$$\eta_s = 1 - \left[1 - \left(\frac{S}{W} \right) \sin \lambda \right] \left[1 - \left(\frac{S}{L} \right) \cos \lambda \tan \theta \right] \quad (4)$$

where

$$\frac{S}{W} = \text{Ratio of collector spacing to aperture width}$$

Figure E-6. Effect of Incidence Angle on Solar Absorptivity

Figure E-7. Geometry for Adjacent Row Shading

$$\frac{S}{L} = \text{Ratio of collector spacing to aperture length}$$

$$\lambda = \text{Solar tracking angle}$$

$$\theta = \text{Solar incidence angle}$$

The above efficiency equation for adjacent collector row shading assumes collectors of equal dimensions and orientation. An equation of the same form can also be derived to account for shading due to collector pylons and receiver tracking and support structure, but because these are very minor losses this will not be done here.

2.2.3 Apparent Aperture Efficiency

Collector energy losses resulting from the orientation of the collector aperture have frequently been called "cosine losses" or the "cosine effect." As Figure E-8 shows, if insolation is modeled as a flux field of equidistant rays with equal energy, the numbers of rays intersecting the aperture diminish with increasing angles of incidence. More precisely, the flux density in the plane of the aperture is reduced from the direct normal value by a factor equivalent to the cosine of the angle of incidence. From a collector efficiency standpoint, this is equivalent to a reduction in the effective aperture area. The effective or "apparent" aperture area is given by

$$A_a = A \cos \theta \quad (5)$$

where

$$A_a = \text{Apparent aperture area (or normal projection of aperture area to rays of insolation)}$$

$$A = \text{Aperture area}$$

$$\theta = \text{Solar incidence angle}$$

An apparent aperture efficiency is defined as

$$\eta_a = \frac{A_a}{A} = \cos \theta. \quad (6)$$

2.2.4 Intercept Efficiency

Energy losses incurred as insolation travels between the collector aperture and the focal line can be classified into two general categories: (1) losses resulting from a failure of the redirected insolation to strike the receiver tube, and (2) losses resulting from the optical properties of the material the insolation comes into contact with. This section will deal only with the first category. The latter category will be covered in the next section.

Figure E-8. View Down the Collector Z (UP) Axis

Insolation can fail to strike the receiver tube in two ways. It can be reflected past (or fail to be reflected on) the end of the tube at the end of a collector row, or it can be reflected past the outer diameter of the tube. The amount of insolation being lost at the ends of a collector row can be quantified by referring to the collector model depicted in Figure E-8. If a longitudinal intercept efficiency ("end loss" efficiency) is defined as the ratio of receiver length receiving reflected insolation to the total receiver length, then

$$\eta_{li} = \frac{L - F + \tan \theta}{L}, \quad (7)$$

where

- η_{li} = Longitudinal intercept efficiency
- L = Receiver row length
- F = Collector focal length
- θ = Solar incidence angle

Mechanical or construction inaccuracies are the primary reason insolation is reflected past the outer diameter of a receiver tube. These inaccuracies cause the insolation to scatter about the focal line resulting in an insolation "blur" rather than a distinct point. The major contributors to this blurring or scattering are the sun's angular width (9.3 mr of arc), tracking error, mirror slope error, (i.e., the angular departure from a tangent to a theoretical parabola), reflective surface irregularity and specularly characteristics (i.e., diffuseness) and the distance travelled by the reflected insolation.

Figure E-9 presents a pictorial model of the blurring process. Incoming rays of insolation are reflected from the reflective surface as cones with vertices at the point of reflection. The intensity of these cones is not uniform but distributed in a "normal" manner - the assumption being that the distribution of the sum of several random variables is approximately a normal distribution (central limit theorem). It should be noted that the flux distributions of all the insolation cones are identical; more precisely, the angular flux density functions all have the same mean and standard deviation (or vertex angle). However, because the distance travelled by the reflected insolation is not uniform, the projection of the angular density functions at the focal point are also not uniform. This results in an asymmetric insolation "blur" (as opposed to a symmetric one) about the focal line. In effect, this blur is a two-dimensional flux density function whose mean is the "sum" of the projected means of all the individual insolation conics and whose spread is the locus of all their projected spreads.

An expression can be developed for this 2-D flux density function in a straightforward manner, although the flux distribution function (the integral of the density function expressing the levels of solar energy about the focal line) cannot be expressed in closed form. However, under the assumption that this latter function can be tabulated, a lateral intercept efficiency can be defined as

$$\eta_{wi} = \frac{\text{Intercepted Blur Energy}}{\text{Total Blur Energy}} = \frac{\int_{-R}^R \int_{-R}^R I(x,y) dx dy}{\int_{-\infty}^{\infty} \int_{-\infty}^{\infty} I(x,y) dx dy} \quad (8)$$

where

η_{wi} = Lateral intercept efficiency

$I(x,y)$ = 2-D flux density function about focal point

R = Radius of receiver tube

The function $I(x,y)$ is completely defined once a mean and standard deviation are specified. As was stated earlier, the mean results from the integration of the projections of all the individual angular density function means, which are assumed unity. The angular density function standard deviation, on the other hand, is a measurable quantity. More precisely, it is the statistical blending of the sun's width, tracking errors, slope errors, and mirror diffuseness; which can be measured, or at least bounded. The standard deviation of the 2-D flux density function is given by

Figure E-9. Dispersion of Reflected Insolation

$$\sigma_{(x,y)} = \sqrt{x^2 + y^2} \sin \sigma_{\text{arc}} \quad (9)$$

where

$$\sigma_{\text{arc}} = \sqrt{(\text{Sun } \sigma)^2 + (\text{Tracking } \sigma)^2 + (\text{Slope Error})^2 + (\text{Reflectors } \sigma)^2} \quad (10)$$

Referring to Figure E-9, the standard deviations in the x-direction and y-direction are given by

$$\sigma_x = F \sin \sigma_{\text{arc}} \quad (11a)$$

$$\sigma_y = 1/2 W \sin \sigma_{\text{arc}} \quad (11b)$$

where

W = Aperture width

F = Focal length

It should be noted that for a 90° rim angle collector such as the BDM T-2100

$$F = 1/4 W \quad (12)$$

The expression for w_i will not be developed beyond this point. Suffice it to say that it is very nearly unity in most cases, and is unity exactly when

$$\sigma_y = 1/6 (\text{Receiver Tube OD}) \quad (13)$$

The diameter resulting from this equation is often used to specify an upper limit on the size of the receiver tube (larger OD tubes will collect no more energy but will lose more heat). An optimum tube size would result from a tradeoff between heat loss savings and diminished energy interception as the tube OD becomes smaller. A probable lower bound for the tube OD is $6 \sigma_K$.

A total intercept efficiency can be written as the product of the longitudinal and lateral intercept efficiencies, i.e.,

$$\eta_i = \eta_{li} \eta_{wi} \quad (14)$$

This efficiency accounts for all collector system energy losses resulting from the failure of the system to focus all of its captured insolation (i.e., insolation passing through the aperture) onto the surface of the receiver tube.

2.2.5 Optical Efficiency

Energy losses resulting from the optical properties of the material the insolation comes into contact with are the second source of losses incurred by the insolation as it travels between the collector aperture and the focal line. In general, these properties, absorptivity, α , reflectivity, r , and transmissivity, τ , are a function of surface characteristics, surface temperature, radiation wavelength, and radiation direction. Notice that Figure E-6 specifies all of these variables for absorptivity; i.e., surface - Nichol at ambient temperature, wavelength - solar, direction - angle of incidence. It is also useful to recall that the sum of these three properties is unity (i.e., $\alpha + r + \tau = 1$).

Insolation comes into contact with three materials as it travels to a parabolic collector's receiver tube: (1) the concentrator reflective surface, (2) the glass jacket, and (3) the receiver tube selective surface coating. The properties for

materials such as these are usually tabulated for a zero angle of incidence and a temperature of 70°F. The tabulated properties also express a weighted average value over an entire spectrum of wavelengths, in this case the solar spectrum. Due to their very nature α , τ , and τ are in effect efficiencies. Therefore, the product of the relevant quantities for the three materials designated above can be used to define an overall optical efficiency. That is,

$$\eta_o = (r_c)(\tau_j)(\alpha_r) \quad (15)$$

where

- η_o = Optical efficiency of collector
- r_c = Reflectivity of concentrator surface at temperature
- τ_j = Transmissivity of glass jacket at temperature
- α_r = Absorptivity of selective surface at temperature

The efficiency as defined above takes into account all optical property dependencies except one - angle of incidence. All three properties experience slight decreases in their values for severe angles of incidence, typically on the order of the variation shown in Figure E-6. From a system level standpoint, the only major impact this could have on η_o is through α_r . That is, since a portion of the insolation striking the receiver tube is at large angles of incidence throughout an entire day (Figure E-9 clearly illustrates this, i.e., the pencils of insolation forming the perimeter of the cones strike the receiver tube at large angles of incidence), the overall absorptivity is in effect reduced slightly from its zero angle of incidence value. When one recalls however that the intensity of the insolation that strikes the receiver tube at high angles of incidence is given by tails of the flux density function, the reduction overall absorptivity would only become consequential for very small tubes, i.e., OD $\leq 6 \sigma_s$. Therefore, for all practical purposes, the collector system optical efficiency remains unaltered from the value given by Equation 15.

2.2.6 Thermal Efficiency

Applying the previously developed efficiencies to the energy captured by the collector will give the amount of energy absorbed by the receiver tube. How much of this absorbed energy is retained by the working fluid depends on the amount of receiver heat loss.

Assuming one-dimensional, steady heat flow, a simple energy balance applied to the system shown in Figure E-3 yields the following equation:

$$\frac{\sigma A_1 (T_1^4 - T_2^4)}{\frac{1}{\epsilon_1} + \frac{A_1}{A_2} \left(\frac{1}{\epsilon_2} - 1 \right)} + \frac{2\pi k_e L (T_1 - T_2)}{\ln \left(\frac{r_2}{r_1} \right)} = h_2 A_2 (T_2 - T_a) + \sigma \epsilon_2 F_{2a} A_2 (T_2^4 - T_a^4) \quad (16)$$

where

h	=	heat transfer coefficient
σ	=	Stefan-Boltzmann constant
ϵ	=	emittance
A	=	area
L	=	length
k_e	=	effective thermal conductivity
F	=	radiation shape factor

All parameters are known in Equation 16 except T_2 . An explicit expression for T_2 is not possible, but it can be solved for in an iterative fashion relatively quickly. Once T_2 is known, the equation is solved and the heat loss is also known.

A thermal efficiency can be defined as

$$\eta_T = \frac{E_a - Q_r}{E_a} \quad (17)$$

where

E_a	=	Energy absorbed by receiver
Q_r	=	Receiver heat loss

After applying this efficiency to the energy absorbed by the receiver, the amount of energy absorbed by the working fluid will finally be known.

2.3 Parabolic Solar Collector Performance Parameters

2.3.1 Performance Optimization

The purpose of this section is to illustrate an approach for optimizing collector system performance. The actual optimization has not been carried out, although examples are given on how this could be accomplished.

The previous section has defined five efficiencies, the products of which give the overall collector efficiency. That is

$$\eta_{COL} = \eta_s \eta_a \eta_i \eta_o \eta_T \quad (18a)$$

$$= \frac{\text{Energy Absorbed by Working Fluid}}{\text{Total Aperture Area} \times \text{Insolation Flux}}$$

where

$$\eta_s = \frac{\text{Unshaded Aperture Area} \times \text{Insolation Flux}}{\text{Total Aperture Area} \times \text{Insolation Flux}} \quad (18b)$$

$$= F_s(S, L, W, \lambda, \theta)$$

$$\eta_a = \frac{\text{Total Captured Energy}}{\text{Unshaded Aperture Area} \times \text{Insolation Flux}} \quad (18c)$$

$$= F_a(\theta)$$

$$\eta_i = \frac{\text{Receiver Interceptible Energy}}{\text{Total Captured Energy}} \quad (18d)$$

$$= F_i(D, L, W, \theta, \sigma_{\text{arc}})$$

$$\eta_o = \frac{\text{Energy Absorbed by Receiver}}{\text{Receiver Interceptible Energy}} \quad (18e)$$

$$= F_o(r_c, \tau_j, \alpha_r)$$

$$\eta_T = \frac{\text{Energy Absorbed by Working Fluid}}{\text{Energy Absorbed by Receiver}} \quad (18f)$$

$$= F_T(\epsilon_r, L, D, t, T_F)$$

2.3.2 Performance Model for the BDM T-2100

The purpose of this section is to express the previously developed efficiencies in terms of the BDM T-2100 design parameters. The resulting equations are then used to produce the results in the next major section of the report.

Applying the Parabolic Collect Model (Equation 18) to the BDM T-2100 requires setting the model variables to the following values:

$$\begin{aligned}
D &= 4.5'' \\
L &= 1000' \\
S &= 50' \\
t &= .215'' \\
W &= 21' \\
T_F^* &= 541^\circ\text{F and } 647^\circ\text{F} \\
\sigma_{\text{arc}} &= 9.0 \text{ mr} \\
r_c &= .95 \\
\alpha_r &= .96 \\
\epsilon_r &= .15 \\
\delta &= 0 \\
\phi &= 0 \\
\gamma &= 34.7^\circ
\end{aligned}$$

For these parameter values, the efficiencies become

$$\begin{aligned}
\eta_s &= 1 - (1 - 2.4 \sin \lambda) (1 - .05 \cos \lambda \tan \theta) \\
\eta_a &= \cos \theta \\
\eta_i &= .98 (1 - .00525 \tan \theta); \quad \eta_{wi} = .98 \text{ for } \sigma_{\text{arc}} = 9.0 \text{ mr} \\
\eta_o &= .830 \\
\eta_t &= 1 - \frac{Qr/L}{\eta_s \eta_a \eta_i \eta_o I W} = 1 - \frac{87.5 \text{ W/M}^2}{\eta_s \eta_a \eta_i \eta_o I}
\end{aligned}$$

where

$$\begin{aligned}
I &= \text{Insolation value in W/m}^2 \\
\theta, \lambda &= \text{Incidence angle and tracking angle, as previously defined}
\end{aligned}$$

*The BDM design calls for 92 collector rows with an average fluid temperature of 647°F and 512 rows with an average temperature of 541°F .

After multiplying, the system level efficiency takes the form

$$\eta_{COL} = F_{COL} (D, L, S, t, W, T_F, \sigma_{arc}, r_c, \tau_j, \alpha_r, \epsilon_r, \delta, \phi, \gamma, HR, DY)$$

where it has been noted that

$$\theta, \lambda = F_{\theta, \lambda} (\delta, \phi, \gamma, HR, DY)$$

and where

D	=	Receiver diameter
L	=	Receiver row length
S	=	Collector row spacing
t	=	Annulus thickness
W	=	Collector aperture width
T _F	=	Working fluid temperature
σ _{arc}	=	Insolation ray standard deviation
r _c	=	Concentrator reflectivity
τ _j	=	Glass jacket transmissivity
α _r	=	Receiver absorptivity
ε _r	=	Receiver emissivity
δ	=	Collector array tilt angle
φ	=	Collector row orientation angle
γ	=	Latitude of collector field
HR	=	Hour of day
DY	=	Day of year

The problem of finding the values of the above 16 variables which maximize η_{COL} is known as a parameter optimization problem. The solution is most easily handled on a computer, although analytical solutions are possible if portions of the system can be optimized independently. For example, since η_{COL} will be maximized if

each of the five subefficiencies which define it was maximized (for a consistent set of the 16 variables), an individual subefficiency can be maximized if it is independent on the other subefficiencies.

Treadwell (Reference E-2) actually does this in his solution for the optimum annulus width, t . The reason the optimum value of the t can be found without solving the entire optimization problem is made clear if one considers η_T . Since t appears only in this subefficiency, a value of t can be found which maximizes η_T given ϵ_r , L , D , and T_f . Thus, the optimum value of t is expressed as a function of these four variables. To further illustrate this concept, consider η_o . Because η_o is the only subefficiency dependent on r_c , τ_j , and α_r , it can be maximized independently. Clearly, the values of r_c , τ_j , and α_r which maximize η_o are 1. Of course, materials which have these property values cannot be found, which introduces the idea of constraints.

Virtually all of the 16 variables defining η_{COL} have some sort of constraint, be it upper or lower bounds (inequality constraints) or even, depending on the design requirements, a single value (e.g., γ was constrained to the value of Barstow, California, for the BDM collector system).

Introducing constraints can significantly alter the complexity of the problem. Fixing a variable which was formerly free makes the problem easier, while introducing inequality constraints can often make the problem more cumbersome.

The optimization problem as it is currently posed is a valid one, but not a very practical one as it has neglected cost. For design purposes, one is more interested in maximizing the ratio of efficiency to cost rather than just efficiency alone.

To accomplish this, a cost model must be developed. The model would typically have the following form:

$$COST = F_{cost}(D, L, S, t, W, T_f, \sigma_{arc}, r_c, \tau_j, \alpha_r, \epsilon_r, \delta, \phi, \gamma)$$

Dividing the previously developed efficiency function by this cost function would create the required performance index. The details required in maximizing this performance index are no different than the ones previously mentioned.

3.0 RESULTS

This section presents the output of the performance model developed in Section 2.0. All of the results were found to compare very closely with BDM's predictions for their collector.

Table E-1 is a sample computer printout of the geometric model developed in Section 2.2.1. The last three columns correspond to the aperture efficiency, η_a , shading efficiency, η_s , and the intercept efficiency, η_i . The middle two columns give the tracking angle and angle of incidence. The intercept and reflective losses are approximately constant at 82 percent. The radiative and convective losses vary with receiver temperature as outlined in Table E-2.

Table E-1

EXAMPLE COMPUTER OUTPUT OF GEOMETRIC MODEL

INPUT NUMBER OF DAYS BEFORE/AFTER SUMMER SOLSTICE (JUNE 21): 0
 BARSTON LATITUDE IS 34 DEGREES, 52 MINUTES (34.867 DEGS)
 INPUT THE LATITUDE IN DEGS: 34.867
 INPUT THE COLLECTOR TILT ANGLE, DEGS FROM HORIZONTAL OF NORTHERN END OF A N/S COLLECTOR:
 INPUT THE COLLECTOR AXIS ORIENTATION ANGLE, DEGS FROM SOUTH TO EAST: 0
 INPUT THE RATIO OF COLLECTOR SPACING TO APERTURE WIDTH: 2.9
 INPUT THE RATIO OF COLLECTOR SPACING TO APERTURE LENGTH: .021
 INPUT THE RATIO OF COLLECTOR FOCAL LENGTH TO APERTURE LENGTH: .00525

HOOR	AZIMUTH	ELEVATION	TRACKING	INCIDENCE	EFFA	EFFS	EFFHD
0.0	0.0	70.0	90.0	11.2	.981	1.000	.999
.5	32.3	77.1	83.0	10.9	.982	1.000	.999
1.0	53.5	72.8	76.0	10.1	.984	1.000	.999
1.5	66.3	67.5	69.2	8.9	.988	1.000	.999
2.0	79.9	61.6	62.5	7.1	.992	1.000	.999
2.5	91.3	55.6	55.9	4.9	.996	1.000	1.000
3.0	96.4	49.5	49.5	2.3	.999	1.000	1.000
3.5	98.8	43.3	43.3	-.6	1.000	1.000	1.000
4.0	94.8	37.2	37.3	-3.9	.998	1.000	1.000
4.5	90.6	31.0	31.3	-7.4	.992	1.000	.999
5.0	102.3	25.0	25.5	-11.1	.981	1.000	.999
5.5	106.0	19.0	19.7	-15.1	.966	.809	.999
6.0	109.7	13.1	13.9	-19.1	.945	.579	.998
6.5	113.5	7.9	8.0	-23.3	.918	.341	.998
7.0	117.6	1.8	2.0	-27.6	.886	.096	.997
7.2	119.0	.0	.0	-29.0	.875	.012	.997

HOURS FROM SOLAR NOON SUN IS ABOVE HORIZON = 7.166675489173

Table E-2
RECEIVER THERMAL LOSSES (BASELINE INCIDENT ENERGY)

Bulk Fluid Temp (°F)	200	400	600	800
Thermal Efficiency (%)	97.5	92.6	87.6	76

When the above efficiencies are combined with the Barstow insolation profiles the resultant overall collector efficiency is shown in Figure E-10. These values verify the result of the BDM analysis.

The remaining uncertainty is the discrepancy between the BDM parabolic trough performance model and the results of the BDM T-700 tests. These discrepancies are illustrated in Figure E-11. It was concluded that σ_{arc} , which significantly affects the intercept efficiency, was selected much too low. To remedy this problem the receiver diameter could be increased or the collector tracking, slope or mirror diffuseness errors could be reduced.

Figure E-10. DN Insolation, Barstow, California, 3 Key Days

MODEL EFFICIENCY COMPARISON $T = 500^{\circ}$

Figure E-11. Model Efficiency Comparison $T = 500^{\circ}$

REFERENCES

- E-1 Anthony F. Veneruso, Tracking Angles and Rates for Single Degree of Freedom Solar Collector, SAND76-0027, Sandia Laboratories, Albuquerque, New Mexico, March 1976.
- E-2 George W. Treadwell, Design Considerations for Parabolic-Cylindrical Solar Collectors, SAND76-0082, Sandia Laboratories, Albuquerque, New Mexico, July 1976.