Assessment of Generic Solar Thermal Systems for Large Power Applications

Volume II

Analysis of Thermal Energy Production Costs for Systems from 50 to 600 MWt

June 1981

Prepared for the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or 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.

The views, opinions and conclusions contained in this report are those of the contractor and do not necessarily represent those of the United States Government or the United States Department of Energy.

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
Under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy \$_____*; Microfiche \$3.00

*Pages	NTIS Selling Price
001-025	\$4.00
026-050	\$4.50
051-075	\$5.25
076-100	\$6.00
101-125	\$6.50
126-150	\$7.25
151-175	\$8.00
176-200	\$9.00
201-225	\$9.25
226-250	\$9.50
251-275	\$10.75
276-300	\$11.00

3 3679 00055 2549

ASSESSMENT OF GENERIC SOLAR
THERMAL SYSTEMS FOR LARGE POWER
APPLICATIONS

VOLUME II

ANALYSIS OF THERMAL ENERGY PRODUCTION
COSTS FOR SYSTEMS FROM 50 TO 600 MWt

S.P. Bird	M.K. Drost
W.J. Apley	J.A. Fort
J.S. Barnhart	B.A. Garrett-Price
D.R. Brown	T.A. Williams

June 1981

Prepared for
the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Richland, Washington 99352

SUMMARY

Under the sponsorship of the U.S. Department of Energy's Division of Solar Thermal Energy Systems, the Pacific Northwest Laboratory performed a comparative analysis of solar thermal concepts that are potentially suitable for development as large process heat systems (50 to 600 Mwt). The concepts considered in the study can be classified into three categories based on the type of solar tracking used by the collector: 1) two-axis tracking, in which concentrators track the sun's motion in both azimuth and altitude, 2) one-axis tracking, in which concentrators track changes in either azimuth or altitude, and 3) non-tracking, in which the concentrators are fixed. Seven generic types of collectors were considered:

Two-Axis tracking:

1. Point Focus Central Receiver (PFCR)
2. Point Focus Distributed Receiver (PFDR)
3. Fixed Mirror Distributed Focus (FDMF)

One-Axis Tracking

4. Line Focus Central Receiver (LFCR)
5. Line Focus Distributed Receiver-Tracking Receiver (LFDR-TR)
6. Line Focus Distributed Receiver-Tracking Collector (LFDR-TC)

Nontracking

7. Low Concentration Nontracking (LCNT)

Conceptual designs developed for the seven systems were based on common assumptions of available technology in the 1990 to 2000 time frame. No attempt was made to perform a detailed optimization of each conceptual design. Rather, designs best suited for a comparative evaluation of the concepts were formulated. Costs were estimated on the basis of identical assumptions, ground rules, methodologies, and unit costs of materials and labor applied uniformly to all of the concepts.

Each of the concepts was evaluated over a range of plant sizes (50, 150, 300, and 600 Mwt). Where practical, the concepts were also analyzed at several different process supply temperatures (150, 350, 500, 1000, and 1500°F). Specifically, the LCNT concept was evaluated at 150 and 350°F; the LFDR-TC concept at 150, 350, and 500°F; the LFDR-TR, LFCR, FMDF, and PFDR at all temperatures except 1500°F; and the PFCR concept at all five process temperatures. Generally, the two-axis tracking systems achieve higher concentration ratios and can be operated at higher temperatures than the one-axis tracking systems.

The computer code SOLSTEP-IPH was used to analyze the thermodynamic performance characteristics and energy costs of the seven concepts. Year-long simulations were performed using meteorological and insolation data for Barstow, California. Results for each concept include levelized energy costs and solar fractions for various combinations of storage capacity and collector field size.

The principal results and conclusions of the analysis include:

- The LFDR-TC concept (parabolic trough) provided the lowest energy costs at low process heat temperatures (150 to 350°F).
- The PFCR concept (central receiver) provided the lowest energy costs at high process heat temperatures (350 to 1500°F).
- The LCNT concept (compound parabolic concentrator) provided energy costs that were significantly higher than any other concept at both of the temperatures for which it was analyzed (150 and 350°F).
- In general, energy costs were strongly dependent on process temperature but relatively independent of plant size over the range considered (50 to 600 Mwt).
- Collector costs are the most significant single cost component for all concepts, process temperatures, and plant sizes.
- Energy transport subsystem costs can be a significant component of total plant cost, especially for concepts using distributed receivers.

FOREWORD

During the past three years the Pacific Northwest Laboratory (PNL) has performed a comparative analysis of solar thermal conversion concepts. The purpose of this study was to characterize, evaluate, and rank the principal solar thermal power concepts under consideration in the U.S. Department of Energy's (DOE) Solar Thermal Power Program, on the basis of an engineering and economic analysis of alternative power plant configurations. A five-volume report on the analysis of small electric power systems (1 to 10 MWe) was issued in 1979-80, consisting of:

- Volume I Executive Summary
- Volume II Identification and Characterization of Concepts for Analysis
- Volume III Analysis of Concepts
- Volume IV Comparative Ranking of Concepts
- Volume V SOLSTEP - A Computer Model for Solar Plant System Simulations.

As a follow-on to the small power systems analysis, two tasks were established for evaluating large power systems. Task 1 involved analyzing the costs for generating electric power from concepts in configurations larger than 10 MWe. Task 2 involved the analysis of thermal energy costs from solar thermal concepts in configurations larger than 50 MWt. This volume is the second of a two-volume report issued in 1980-81 on the analysis of large power systems:

- Volume I Analysis of Electric Power Generating Costs
- Volume II Analysis of Thermal Energy Production Costs.

All the comparative studies have been sponsored by DOE's Division of Solar Thermal Energy Systems, Office of Solar Industrial Applications.

ACKNOWLEDGMENTS

This work was supported by the U.S. Department of Energy's Division of Solar Thermal Energy Systems. The authors would like to acknowledge the special assistance of D. F. Adamski of Harris Thermal Transfer Products, Inc. We also wish to express our appreciation to Dr. W. W. Laity of the Pacific Northwest Laboratory for guidance and management support during this study.

CONTENTS

SUMMARY	iii
FOREWORD	v
ACKNOWLEDGMENTS	vii
1.0 INTRODUCTION	1.1
1.1 PURPOSE OF STUDY	1.1
1.2 SCOPE OF STUDY	1.2
1.3 GENERAL GROUND RULES AND ASSUMPTIONS	1.2
1.4 LIMITATIONS	1.4
2.0 CONCEPTS ANALYZED	2.1
2.1 TWO-AXIS TRACKING	2.3
2.1.1 Point Focus Central Receiver (PFCR)	2.3
2.1.2 Point Focus Distributed Receiver (PFDR)	2.3
2.1.3 Fixed Mirror Distributed Focus (FMDF)	2.6
2.2 ONE-AXIS TRACKING	2.6
2.2.1 Line Focus Central Receiver (LFCR)	2.6
2.2.2 Line Focus Distributed Receiver-Tracking Receiver (LFDR-TR)	2.9
2.2.3 Line Focus Distributed Receiver-Tracking Collector (LFDR-TC)	2.9
2.3 LOW CONCENTRATION NONTRACKING CONCEPT (LCNT)	2.12
3.0 FORMULATION OF CONCEPTS FOR ANALYSIS	3.1
3.1 PERFORMANCE GROUND RULES AND ASSUMPTIONS	3.1
3.2 COLLECTOR SUBSYSTEM	3.2
3.2.1 Concentrator Optics	3.5
3.2.2 Receiver Design	3.5
3.2.3 Receiver Performance	3.6

CONTENTS (contd)

3.2.4	Collector Efficiency	3.8
3.3	TRANSPORT SUBSYSTEM	3.9
3.3.1	PFDR and FMDF Transport Subsystems	3.9
3.3.2	LCNT, LFDR-TR, and LFDR-TC Transport Subsystems	3.9
3.3.3	PFCR and LFCR Transport Subsystems	3.12
3.4	STORAGE SUBSYSTEM	3.12
3.4.1	Water/Ethylene Glycol Storage Subsystem	3.13
3.4.2	Oil and Rock Storage Subsystem	3.13
3.4.3	Molten Salt Storage	3.15
3.4.4	Pebble Bed Storage	3.16
3.5	INTERFACE SUBSYSTEM	3.16
3.5.1	Water - Water/Ethylene Glycol Interface Subsystem	3.16
3.5.2	Water/Steam - Oil Interface Subsystem	3.17
3.5.3	Air - Molten Salt Interface Subsystem	3.17
3.5.4	Summary of Interface Subsystem	3.17
3.6	SUMMARY OF KEY PERFORMANCE PARAMETERS	3.19
4.0	ESTIMATION OF COSTS	4.1
4.1	ECONOMIC GROUND RULES AND ASSUMPTIONS	4.2
4.2	CAPITAL INVESTMENT COST ESTIMATING	4.6
4.2.1	Collector Subsystem Costs	4.6
4.2.2	Transport Subsystem Costs	4.11
4.2.3	Storage Subsystem Costs	4.13
4.2.4	Interface Subsystem Costs	4.18
4.2.5	Balance of Plant Costs	4.20

CONTENTS (contd)

4.2.6	Indirect and Contingency Costs	.	.	.	.	.	.	4.24
4.3	OPERATION AND MAINTENANCE COSTS	.	.	.	.	.	.	4.24
4.3.1	Direct Production Costs	.	.	.	.	.	.	4.26
4.3.2	Purchased Energy Costs	.	.	.	.	.	.	4.26
4.3.3	Maintenance Costs	.	.	.	.	.	.	4.26
4.3.4	Overhead Costs	.	.	.	.	.	.	4.29
4.4	SUMMARY OF KEY COST ESTIMATES	.	.	.	.	.	.	4.29
5.0	RESULTS	.	.	.	.	.	.	5.1
5.1	DESCRIPTIONS OF ATTRIBUTES	.	.	.	.	.	.	5.1
5.2	LEVELIZED ENERGY COST AND SOLAR FRACTION	.	.	.	.	.	.	5.3
5.3	LEVELIZED ENERGY COST AND PROCESS TEMPERATURE	.	.	.	.	.	.	5.5
5.4	LEVELIZED ENERGY COST AND PLANT SIZE	.	.	.	.	.	.	5.8
5.5	CAPITAL COST	.	.	.	.	.	.	5.8
6.0	COMMENTS, CONCLUSIONS, AND RECOMMENDATIONS	.	.	.	.	.	.	6.1
7.0	REFERENCES	.	.	.	.	.	.	7.1
	APPENDIX A - ANALYSIS CODES	.	.	.	.	.	.	A.1
	APPENDIX B - ENERGY COST RESULTS	.	.	.	.	.	.	B.1
	APPENDIX C - COST ESTIMATE SCALING RELATIONSHIPS	.	.	.	.	.	.	C.1

FIGURES

2.1	Point Focus Central Receiver Concept	.	.	.	.	.	.	2.4
2.2	Point Focus Distributed Receiver Concept	.	.	.	.	.	.	2.5
2.3	Fixed Mirror Distributed Focus Concept	.	.	.	.	.	.	2.7
2.4	Line Focus Central Receiver Concept	.	.	.	.	.	.	2.8
2.5	Line Focus Distributed Receiver - Tracking Receiver Concept	.	.	.	.	.	.	2.10
2.6	Line Focus Distributed Receiver - Tracking Collector Concept	.	.	.	.	.	.	2.11
2.7	Low Concentration Nontracking Concept	.	.	.	.	.	.	2.13
3.1	Collector Efficiency for 300-MWt Plants with 0.4 Solar Fraction	.	.	.	.	.	.	3.7
3.2	Dish Transport Subsystem Layout	.	.	.	.	.	.	3.10
3.3	Trough Transport Subsystem Layout	.	.	.	.	.	.	3.11
4.1	Central Receiver Absorber Costs	.	.	.	.	.	.	4.9
4.2	Central Receiver Tower Costs	.	.	.	.	.	.	4.10
4.3	Sample Storage Component Costs	.	.	.	.	.	.	4.15
5.1	Relationship of Levelized Energy Costs to Increasing Annual Costs	.	.	.	.	.	.	5.3
5.2	Levelized Energy Costs for 300-MWt PFCR Concepts	.	.	.	.	.	.	5.4
5.3	Levelized Energy Costs at 50 MWt	.	.	.	.	.	.	5.6
5.4	Levelized Energy Costs at 150 MWt	.	.	.	.	.	.	5.6
5.5	Levelized Energy Costs at 300 MWt	.	.	.	.	.	.	5.7
5.6	Levelized Energy Costs at 600 MWt	.	.	.	.	.	.	5.7
5.7	Levelized Energy Costs at 500°F	.	.	.	.	.	.	5.8
5.8	Sample Breakdown of Capital Costs	.	.	.	.	.	.	5.10
A.1	ETRANS Solution Procedure Outline	.	.	.	.	.	.	A.7
A.2	Sample Plot of Energy Cost Versus Solar Fraction	.	.	.	.	.	.	A.10

TABLES

2.1	Concepts Selected for Analysis	.	.	.	.	.	.	.	2.1
2.2	Subsystem Selection	.	.	.	.	.	.	.	2.2
2.3	Summary of Concept Characteristics	.	.	.	.	.	.	.	2.14
3.1	Working Fluids and Pipe Insulation Materials for the Temperature Ranges Studied	.	.	.	.	.	.	.	3.9
3.2	Description of Interface Subsystems	.	.	.	.	.	.	.	3.18
3.3	Summary of Key Performance Parameters	.	.	.	.	.	.	.	3.20
4.1	Economic Ground Rules and Assumptions	.	.	.	.	.	.	.	4.4
4.2	Collector Subsystem Costs	.	.	.	.	.	.	.	4.8
4.3	Transport Subsystem Costs	.	.	.	.	.	.	.	4.12
4.4	Storage Subsystem Costs	.	.	.	.	.	.	.	4.16
4.5	Interface Subsystem Costs	.	.	.	.	.	.	.	4.23
4.6	Balance-of-Plant Component Costs	.	.	.	.	.	.	.	4.22
4.7	Summary of Key Cost Estimates	.	.	.	.	.	.	.	4.30
C.1	Cost Estimate Scaling Relationships for Capital Investment Costs	.	.	.	.	.	.	.	C.2
C.2	Cost Estimate Scaling Relationships for Operation and Maintenance Costs	.	.	.	.	.	.	.	C.3

ASSESSMENT OF GENERIC SOLAR THERMAL SYSTEMS FOR LARGE POWER APPLICATIONS

VOLUME II

ANALYSIS OF THERMAL ENERGY PRODUCTION COSTS FOR SYSTEMS FROM 50 TO 600 MWt

1.0 INTRODUCTION

Under the sponsorship of the U.S. Department of Energy's (DOE) Division of Solar Thermal Energy Systems, Office of Solar Industrial Applications, the Pacific Northwest Laboratory (PNL) performed a comparative analysis of solar thermal conversion concepts. The purpose of this study was to characterize, evaluate, and rank the principal solar thermal power concepts under consideration in the DOE Solar Thermal Power Program, based on an engineering and economic analysis of alternative power plant configurations. Task 1 involved the analysis of costs for generating electric power from concepts in configurations larger than 10 MWe. Task 2 involved the analysis of thermal energy costs from solar thermal concepts in configurations from 50 to 600 MWt. This second volume of the PNL report documents the work performed on Task 2.

1.1 PURPOSE OF STUDY

The primary purpose of the most recent study (Task 2) was to provide DOE with an independent, objective assessment of the principal solar thermal concepts that have the potential for achieving commercial success as large thermal energy producing systems (50 to 600 MWt). This evaluation was performed as a follow-on study to assessments of 1- to 10-MWe solar thermal electric plants (Laity et al. 1979) and 50- to 200-MWe solar thermal electric plants (Apley et al. 1980) conducted previously for DOE. The results of this assessment will provide guidance for DOE in making decisions on which concepts warrant priority attention for further technology development.

1.2 SCOPE OF STUDY

Seven generic types of collectors were considered in this study. Each collector design comprises a concentrator that reflects and concentrates the radiant energy and a receiver where the energy is transferred to a working fluid. The collectors can be classified into three categories: 1) two-axis tracking, in which the concentrators track the sun's motion in both azimuth and altitude; 2) one-axis tracking, in which the concentrators track changes in either azimuth or altitude; and 3) nontracking, in which the concentrators are fixed.

The seven types of collectors were analyzed in conceptually designed plant configurations covering a range of sizes from 50 to 600 MWt and, where possible, a range of temperatures from 150°F (65°C) to 1500°F (816°C). Specifically, the conceptual designs were analyzed in plant sizes of 50, 150, 300, and 600 MWt. The process temperatures investigated were 150°F (65°C), 350°F (177°C), 500°F (260°C), 1000°F (538°C), and 1500°F (816°C). All of the collectors were evaluated at the lowest temperature. Each concept was also evaluated at each of the progressively higher temperatures up to the maximum practical operating temperature for that concept.

In this study, attention was restricted to collector concepts that are potentially suitable for development as large power systems in the mid term (1990-2000), with initial commercialization by the mid-1980s. The concepts were analyzed in configurations designed solely to generate solar-produced thermal energy for process heat applications. Cogeneration and solar/fossil hybrid systems were not included in the study.

1.3 GENERAL GROUND RULES AND ASSUMPTIONS

Several ground rules and assumptions were developed at the outset of the study to ensure that the concepts were evaluated on a uniform basis and to make the analysis tractable. Ground rules and assumptions dealing specifically with the performance analysis or economic analysis are described in Sections 3.1 and 4.1, respectively. Ground rules and assumptions relating to the study in general include:

1. The aim of the study was to evaluate generic solar thermal concepts. Descriptions of the collector components (concentrators and receivers) were based on designs currently proposed for each generic concept. Selection of specific aspects of any single design was based on the extent to which the design represented the generic concept and the amount of design information available. In all cases, designs for particular concepts were uniformly modified to reflect developments in structures, optical coatings, selective surfaces, and other features that could be expected by the 1990 to 2000 time frame.
2. The plants were assumed to be connected to a private industrial process heat user.
3. The plants were designed for a strictly solar/process heat application. Cogeneration and solar/fossil hybrid systems were not included in the study.
4. The plants were assumed to be located in an area similar to Barstow, California.
5. The performance of each plant was characterized in terms of a solar fraction (SF), defined as

$$SF = \frac{\text{Total energy generated in a year (kWh)}}{\text{Rated capacity (kW) x number of hours in a year}}$$

Thus, the solar fraction represents the ratio of the amount of energy actually produced by the plant to the amount of energy that the plant would have produced had it operated all the time at the rated capacity. For this study the solar fraction does not account for scheduled or unscheduled plant outages. That is, the total energy generated assumes that the plant can operate whenever insolation or energy from storage is available.

6. The cost of each plant was characterized in terms of a levelized energy cost (LEC), defined as

$$\text{LEC} = \frac{\text{Annualized cost of plant (\$)}}{\text{Total energy generated in a year (MMBtu)}}$$

The levelized energy cost represents the before-tax price at which energy could be sold to exactly recover the full cost of the plant over its lifetime, including a return on investment. The full cost of the plant includes construction costs, operating and maintenance costs, and the cost of purchased electrical energy required to run the plant auxiliary loads.

1.4 LIMITATIONS

The aim of the study was to provide a comparative assessment of solar thermal power systems for process heat applications. For the comparative assessment a great deal of effort was expended to ensure that the relative performance and costs of the concepts were accurately characterized. Less effort was spent to ensure the absolute accuracy of the analysis. For example, the reflectivities of the concentrator surfaces projected in the study should accurately represent the relative differences of collector concepts. However, unforeseen developments could provide better reflective surfaces that would improve the absolute performance of all concepts. Likewise, the economic assumptions used in the study strongly affect the absolute values of the levelized energy costs presented, but they do not significantly affect the relative magnitudes of the energy costs. When comparing the results presented here with results of other studies, it is necessary to be aware of the differences in performance and economic assumptions that are bound to exist.

2.0 CONCEPTS ANALYZED

The initial step in evaluating the alternative solar thermal industrial process heat systems was to identify those concepts that best represented the advanced generic types currently being proposed in the DOE solar thermal program. A similar process was used in the assessment of solar options for electric power applications. Where possible, the concept configurations used in the assessment of solar options for large electric systems were also used in the assessment of solar options for industrial process heat applications. The configurations selected for analysis can be classified on the basis of tracking method. Table 2.1 presents the seven generic collector systems and includes the nomenclature used to identify the individual concepts.

As operating temperature increases, some generic concepts are dropped from further consideration. This is caused by temperature limitations inherent in a given design. Table 2.1 shows which concepts were considered at each temperature range.

TABLE 2.1 Concepts Selected for Analysis

Concept	Product Temperature					Symbol
	150°F	350°F	500°F	1000°F	1500°F	
<u>TWO-AXIS TRACKING</u>						
Point Focus Central Receiver	Yes	Yes	Yes	Yes	Yes	PFCR
Point Focus Distributed Receiver	Yes	Yes	Yes	Yes	--	PFDR
Fixed Mirror Distributed Focus	Yes	Yes	Yes	Yes	--	F MDF
<u>ONE-AXIS TRACKING</u>						
Line Focus Central Receiver	Yes	Yes	Yes	Yes	--	LF CR
Line Focus Distributed Receiver						
- Tracking Receiver	Yes	Yes	Yes	Yes	--	LFDR-TR
- Tracking Collector	Yes	Yes	Yes	--	--	LFDR-TC
<u>NONTRACKING</u>						
Low Concentration Nontracking	Yes	Yes	--	--	--	LCNT

The goal of the study was to compare generic concepts across a wide range of power levels and operating temperatures. This required that subsystem optimization be kept to a minimum. In order to reduce the variations considered for each concept, a combination of transport subsystem, storage subsystem, and interface subsystem was specified for each operating temperature. At each power level and operating temperature the appropriate generic concepts were compared using the specified transport, storage, and interface subsystems. Although the transport subsystem type was specified at each power level, the actual design of the transport subsystem was determined by the collector type. The subsystem types specified at each temperature range are presented in Table 2.2. Throughout the remainder of this report, concepts and subsystems will be identified according to the product temperature. Note, however, that the peak temperature in the receiver, transport, and storage subsystems is actually the working fluid temperatures. A summary of concept characteristics is presented in Table 2.3, which appears after the concept discussion.

TABLE 2.2. Subsystem Selection

<u>Product</u>	<u>Product Temperature</u>	<u>Interface Subsystem</u>	<u>Working Fluid/Transport Subsystem</u>	<u>Working Fluid Temperature</u>	<u>Storage Subsystem</u>
Hot Water	150 ⁰ F	Water/Water Heat Exchanger	50% Water, 50% Ethylene Glycol	250 ⁰ F	Water
Saturated Steam	350 ⁰ F	Oil/Steam Heat Exchanger	Oil (Caloria HT 43)	450 ⁰ F	Oil/Rock
Saturated Steam	500 ⁰ F	Oil/Steam Heat Exchanger	Oil (Caloria HT 43)	575 ⁰ F	Oil/Rock
Hot Air	1000 ⁰ F	Molten Salt Air Heat Exchanger	Molten Salt (Draw Salt)	1050 ⁰ F	Molten Salt
Hot Air	1500 ⁰ F	None	Air	1500 ⁰ F	Pebble Bed

2.1 TWO-AXIS TRACKING

Two-axis tracking concepts use concentrators and receivers that can be oriented individually or collectively to focus the sun's image on a receiver. The capability to track the sun's diurnal motion in both azimuth and altitude allows for very high concentration ratios. The availability of high concentration ratios means that higher system working fluid temperatures may be obtained. Three two-axis tracking concepts were considered: the Point Focus Central Receiver, the Point Focus Distributed Receiver, and the Fixed Mirror Distributed Focus concept.

2.1.1 Point Focus Central Receiver (PFCR)

Point Focus Central Receiver concepts employ a large array of mirrors that track the sun in two axes, redirecting the incident radiation onto a receiver located on the top of a fixed tower. The general system is shown in Figure 2.1; however, it is important to note that the heliostat field shape can change dramatically when cavity receivers are considered. The same heliostat and support assembly were used for all PFCR cases. The selected heliostat design is based on the McDonnell Douglas second-generation prototype with a 49-m^2 aperture area.

The Point Focus Central Receiver was the only concept analyzed at all temperature ranges. A cavity air heating receiver was used at the 1500°F operating temperature. A cavity molten salt heating receiver was used at the 1000°F operating temperature. An external oil heating receiver was used at both the 500°F and the 350°F operating temperatures. An external water heating receiver was considered at 150°F .

2.1.2 Point Focus Distributed Receiver (PFDR)

The Point Focus Distributed Receiver concepts employ an array of parabolic dishes that track the sun in two axes, redirecting the incident radiation onto individual cavity receivers located at the focal point of each separate parabolic concentrator. A generic plant concept is shown in Figure 2.2. The same parabolic concentrator (100-m^2 aperture area) and support assembly were used for all Point Focus Distributed Receiver cases.

FIGURE 2.1. Point Focus Central Receiver Concept

FIGURE 2.2. Point Focus Distributed Receiver Concept

The Point Focus Distributed Receiver concept was considered for all operating temperatures except 1500⁰F. The Point Focus Distributed Receiver concept was not considered suitable for the high-temperature case because of the lack of a reliable method of transporting the thermal energy from the distributed receivers to a central storage and interface subsystem.

2.1.3 Fixed Mirror Distributed Focus (FMDf)

The Fixed Mirror Distributed Focus concept is a large bowl-like structure consisting of individual mirror panels attached to a criss-cross concrete frame. The entire bowl is canted 15⁰ to the south. A boom/crane assembly maintains the tube-wound, cylindrical receiver within the moving focal region of the bowl during all daylight hours. Each bowl is 200 ft in diameter. The plant includes a number of distributed bowls as shown in Figure 2.3. The energy is extracted from receivers and piped to a central storage and interface subsystem.

The Fixed Mirror Distributed Focus concept was considered for all operating temperatures except 1500⁰F. At 1500⁰F the losses from the exposed receiver were excessive.

2.2 ONE-AXIS TRACKING

One-axis tracking concepts use linear concentrators that can rotate around one axis to track the sun's diurnal motion. In general, one-axis tracking does not achieve the very high concentration ratios available with the two-axis tracking concepts. However, one-axis tracking requires a less complicated and potentially less expensive collector. Three one-axis tracking concepts were considered: the Line Focus Central Receiver concept, the Line Focus Distributed Receiver with a Tracking Receiver, and the Line Focus Distributed Receiver with a Tracking Collector.

2.2.1 Line Focus Central Receiver (LFCR)

The Line Focus Central Receiver concept (Figure 2.4) uses an array of rectangular single-axis heliostats to focus incident solar radiation onto an elevated line central receiver. The heliostats are arranged in a concentrator field on the north side of the receiver. The heliostats track the sun

FIGURE 2.3. Fixed Mirror Distributed Focus Concept

FIGURE 2.4. Line Focus Central Receiver Concept

automatically and concentrate the insolation on the receiver. The cavity linear receiver is mounted on towers, and has sufficient length to absorb the energy collected in the heliostat field. The heat transport fluid is supplied to the receiver sections by the transport subsystem piping network and is returned in a central storage and interface subsystem.

The Line Focus Central Receiver concept was considered for all operating temperatures except 1500⁰F. Excessive receiver losses and the lack of a reliable method of transporting thermal energy at 1500⁰F eliminated this concept from consideration at the higher operating temperature.

2.2.2 Line Focus Distributed Receiver-Tracking Receiver (LFDR-TR)

The Line Focus Distributed Receiver-Tracking Receiver concept uses a fixed mirror concentrator that produces a sharp line focus regardless of the sun's position (see Figure 2.5). The receiver is moved in a circular arc to track the focal line. The segmented concentrator is a concave array of long, narrow, flat mirror facets fixed to a concrete support. The movable receiver consists of a selectively coated, enclosed receiver tube with a compound parabolic secondary concentrator. Energy is transported from the collector field by a heat transport fluid to a central storage and interface subsystem.

The Line Focus Distributed Receiver - Tracking Receiver concept was considered for all operating temperatures except 1500⁰F. Excessive receiver losses and the lack of a reliable method of transporting thermal energy at 1500⁰F eliminated this concept from consideration at the highest operating temperature.

2.2.3 Line Focus Distributed Receiver-Tracking Collector (LFDR-TC)

The Line Focus Distributed Receiver-Tracking Collector concept uses a collector segment consisting of a single-curvature concentrator that focuses solar insolation on a fixed linear receiver. The collector is rotated around one axis to track the sun's diurnal motion. The concentrator is a parabolic trough; the receiver consists of a glass-enclosed, selectively coated receiver tube, as shown in Figure 2.6. The collector segments are placed in standard modules arranged to form the collector field. Energy is transported from the collector field by a heat transport fluid to a central storage and interface subsystem.

FIGURE 2.5. Line Focus Distributed Receiver - Tracking Receiver Concept

FIGURE 2.6. Line Focus Distributed Receiver - Tracking Collector Concept

The Line Focus Distributed Receiver-Tracking Collector was considered for the 150°F, 350°F and 500°F operating temperatures. The concept was not considered at higher temperatures because of excessive receiver losses.

2.3 LOW CONCENTRATION NONTRACKING CONCEPT (LCNT)

Nontracking systems, such as flat plate collectors, are capable of producing maximum operating temperatures approximately 200°F greater than ambient. Because higher temperatures are required by many process heat applications, some form of concentrating mirror must be included as part of a stationary collector. While several different nontracking configurations have been proposed, the compound parabolic concentrator (CPC) collector appears to provide the highest operating temperature with the smallest number of seasonal axial tilt changes.

The LCNT concept uses a compound parabolic concentrator to redirect incident solar radiation onto a selectively coated, tubular vacuum receiver. The CPC is a nonimaging concentrator, which allows a more precise concentration than do conventional mirrors. However, there is also a corresponding tradeoff between achievable concentration ratio and number of tilt adjustments required per year. The system used in this study is a truncated 7.2x CPC with an effective net concentration of 5.25, which requires only 12 tilt adjustments per year. As shown in Figure 2.7, the CPC segments are arranged to form the collector field. Energy is transported from the collector field by a heat transport fluid to a central storage and interface subsystem.

The Low Concentration Nontracking concept was considered for operating temperatures of 150°F and 350°F. Because of significant increases in thermal losses at higher operating temperatures and a low concentration ratio, the LCNT concept was not used for operating temperatures of 500°F and above.

FIGURE 2.7. Low Concentration Nontracking Concept

TABLE 2.3. Summary of Concept Characteristics

Concept	Product Temperature	Product	Concentrator	Receiver	Transport Subsystem	Storage Subsystem
PFCR	1500°F	Hot air, 100 psi	49-m ² Heliostat	Cavity	Hot air	Pebble bed
PFCR	1000°F	Hot air, 100 psi	49-m ² Heliostat	Cavity	Draw salt	Draw salt
PFCR	500°F	Saturated steam	49-m ² Heliostat	External	Caloria HT43	Caloria HT43/Rock
PFCR	350°F	Saturated steam	49-m ² Heliostat	External	Caloria HT43	Caloria HT43/Rock
PFCR	150°F	Hot water	49-m ² Heliostat	External	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
PFDR	1000°F	Hot air, 100 psi	11-m Paraboloidal dish	Cavity	Draw salt	Draw salt
PFDR	500°F	Saturated steam	11-m Paraboloidal dish	Cavity	Caloria HT43	Caloria HT43
PFDR	350°F	Saturated steam	11-m Paraboloidal dish	Cavity	Caloria HT43	Caloria HT43
PFDR	150°F	Hot water	11-m Paraboloidal dish	Cavity	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
FMOF	1000°F	Hot air, 100 psi	61-m Hemispherical bowl	External	Draw salt	Draw salt
FMOF	500°F	Saturated steam	61-m Hemispherical bowl	External	Caloria HT43	Caloria HT43
FMOF	350°F	Saturated steam	61-m Hemispherical bowl	External	Caloria HT43	Caloria HT43
FMOF	150°F	Hot water	61-m Hemispherical bowl	External	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
LFCR	1000°F	Hot air, 100 psi	Linear heliostat	Linear cavity	Draw salt	Draw salt
LFCR	500°F	Saturated steam	Linear heliostat	Linear cavity	Caloria HT43	Caloria HT43
LFCR	350°F	Saturated steam	Linear heliostat	Linear cavity	Caloria HT43	Caloria HT43
LFCR	150°F	Hot water	Linear heliostat	Linear cavity	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
LFDR-TR	1000°F	Hot air, 100 psi	Segmented trough	Glass enclosed tube	Draw salt	Draw salt
LFDR-TR	500°F	Saturated steam	Segmented trough	Glass enclosed tube	Caloria HT43	Caloria HT43/Rock
LFDR-TR	350°F	Saturated steam	Segmented trough	Glass enclosed tube	Caloria HT43	Caloria HT43/Rock
LFDR-TR	150°F	Hot water	Segmented trough	Glass enclosed tube	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
LFDR-TC	500°F	Saturated steam	Parabolic trough	Glass enclosed tube	Caloria HT43	Caloria HT43/Rock
LFDR-TC	350°F	Saturated steam	Parabolic trough	Glass enclosed tube	Caloria HT43	Caloria HT43/Rock
LFDR-TC	150°F	Hot water	Parabolic trough	Glass enclosed tube	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol
LCNT	350°F	Saturated steam	Compound parabolic concentrator	Evacuated tube	Caloria HT43	Caloria HT43/Rock
LCNT	150°F	Hot water	Compound parabolic concentrator	Evacuated tube	50% water/50% Ethylene Glycol	50% water/50% Ethylene Glycol

3.0 FORMULATION OF CONCEPTS FOR ANALYSIS

It was necessary to formulate conceptual designs for each of the seven generic concepts to serve as a basis for estimating system performance and cost. To facilitate the conceptual designs, each concept was subdivided into four subsystems: collector subsystem, transport subsystem, storage subsystem, and interface subsystem. The performance and cost parameters derived for each conceptual design were then used to model the concepts with the SOLSTEP-IPH solar thermal power plant simulation code (see Appendix A). This section describes the project approach, includes a description of each subsystem, and summarizes the performance parameters used in the SOLSTEP-IPH simulations.

3.1 PERFORMANCE GROUND RULES AND ASSUMPTIONS

The performance analysis included the development of a set of design assumptions applicable to all seven generic concepts. Design assumptions specific to an individual subsystem are discussed in the following sections; those common to all subsystems will be discussed here. Four general design assumptions were identified:

1. Demand Profile--The performance calculations were based on an industrial process heat user capable of using all available plant output up to the nominal plant rating. This ground rule eliminated the need for the plant to match daily or seasonal load variations.
2. Subsystems Standardization--Common subsystems and components were assumed where reasonable. The same energy storage and interface subsystems were used for all concepts at a given temperature. The transport subsystem was characterized for each concept, but even here the same working fluid, pipe, and insulating materials were used for all concepts at a given temperature range.

3. Suboptimization--The project scope did not include a detailed sub-optimization of components and subsystems. Previous studies were relied upon to establish appropriate values for operating parameters such as pressure, temperature, and collector field layout features. The transport subsystem was one major exception. Because of the availability of the PNL-developed piping code ETRANS, a detailed sub-optimization of the transport subsystem was completed for all concepts.
4. Auxiliary Power--Unlike solar thermal electric concepts, strict solar industrial process heat concepts do not provide their own auxiliary power. Auxiliary electric power is assumed to be provided by a utility grid connection and purchased at market rates.
5. Meteorology--The plant performance was estimated by hourly simulations using insolation and meteorological data from Barstow, California. These data were collected by WEST Associates during 1976 and provided to PNL by the Jet Propulsion Laboratory.

3.2 COLLECTOR SUBSYSTEM

The collector subsystem, which consists of the concentrator and receiver, is the basic building block of the solar thermal system. To accurately model the transient ambient conditions affecting overall plant performance, it is necessary to characterize collector performance in appropriate detail. The optical performance of the concentrator and thermal performance of the receiver need to be accurately determined for both the steady-state and transient case. The models and analysis used to determine the collector performance are described in more detail by Laity et al. (1980b).

3.2.1 Concentrator Optics

For every generic concept the optics must be determined for different field arrangements, ground cover ratios, tower heights, north-south and east-west mirror separation distances, and tilt angles. The particular configuration can then be costed and simulation runs conducted until optimal performance and cost numbers are obtained. Economics and optical performance are not

independent quantities; although the optical performance directly determines the system cost, the cost of individual subsystems and services will also determine the positioning, cleaning frequency, potential tracking accuracy, and, therefore, the overall optical efficiency. Because the economic and performance simulation was based on data for 1976 at Barstow, California, collector optics calculations were required at that location for all expected altitude and azimuth angles.

Concentrator optical performance for small and medium-size Point Focus Central Receiver systems was calculated with the assistance of a team at the Solar Energy Laboratory, University of Houston, under the direction of Dr. Lorin Vant-Hull. With component performance and cost data provided by PNL, concentrator optical performance for optimally configured heliostat fields and tower heights was determined. Optical efficiency values were scaled to larger plant field sizes when appropriate and when comparable studies were available. Using the MIRVAL computer code (Leary and Hankins 1979), Sandia Laboratories-Livermore provided field layout and optical performance data for large central receiver plants.

Concentrator optical performance for the Point Focus Distributed Receiver systems was determined using a PNL-developed computer code, SHADE (Apley 1979).

Concentrator optical performance for the Fixed Mirror Distributed Focus concept was obtained from the major proponents of the Crosbyton Project (Texas Tech University and E-Systems, Inc.). Two methods were used to validate the predictions made by the concept proponents:

- An independent assessment of a stationary reflector with a tracking absorber (Clausing 1976) was compared to the information obtained from Texas Tech University and E-Systems, Inc.
- PNL staff evaluated the optical performance models used by Texas Tech University and E-Systems, Inc.

Concentrator optical performance for the Line Focus Central Receiver concept was determined using a PNL-developed computer program. The PNL calculations for similar field sizes examined by FMC Corporation provided results

that were comparable to data generated by the FMC Line Focus Central Receiver Code (Laity et al. 1980a).

Concentrator optical performance for the Line Focus Distributed Receiver - Tracking Receiver concept was determined using a PNL-developed computer program. The Fixed Mirror Solar Concentrator (FMSC) design proposed by General Atomic was used for this study. The PNL code calculations were compared with theoretical determinations by General Atomic (Russell et al. 1976; Schuster et al. 1979), calculations conducted using the General Atomic analytical code SUNPOW, and experimental performance testing at the Midtemperature Solar Systems Test Facility (Workhoven and Dudley 1978).

Concentrator optical performance for the Line Focus Distributed Receiver - Tracking Collector concept was determined using a PNL-developed computer program. North-south, east-west, and polar axis orientations were analyzed. The north-south system provided the most economic energy absorption within the constraints of this study. This conclusion was supported by similar analyses by Honeywell and Black and Veatch (Powell et al. 1977, p. 67). A parabolic trough design closely resembling the Solar Kinetics Collector was chosen because that collector was proven to be an efficient design at the Sandia Collector Module Test Facility. Calculations by the PNL code were compared with theoretical determinations by JPL (Caputo 1975) and Black and Veatch (1977), as well as with the experimental results obtained at the Sandia Test Facility.

Optical performance for the Low Concentration Nontracking concept was determined using a PNL-developed computer program. A 5.25x compound parabolic concentrator (CPC) similar to designs proposed by the University of Chicago, Argonne National Laboratory, and Arthur D. Little was evaluated as the base system (Cole, Schertz, and Teagan, 1977a; Collares-Pereira et al. 1978). Results calculated by the PNL code were compared with theoretical determinations by Argonne National Laboratory and Arthur D. Little and, with modifications, were similar to experimental results obtained by Argonne National Laboratory for a 1.5x concentrator (Cole, Schertz, and Teagan 1977b, p. 11; Laity et al. 1980a).

3.2.2 Receiver Design

The variety of working fluid temperatures considered for each generic concept allows for a choice in receiver materials and in one case, overall receiver design. An external receiver was selected for use with the 150°F, 350°F, and 500°F PFCR concepts. Greater thermal losses required the use of a cavity receiver design for the 1000°F and 1500°F cases. The remainder of the concepts used a single receiver type for all temperatures. Because of the relaxed material constraints, carbon steel was selected as the receiver material for the 150°F, 350°F and 500°F cases of each concept. More expensive materials were required for the higher temperature cases. Finally, for each case, receiver tubing diameter and length were varied to provide acceptable values of receiver pressure drop and wall temperature.

3.2.3 Receiver Performance

The thermal efficiency of the receivers used for the generic systems has a major effect on the overall system performance. Thermal losses are strongly dependent on the working fluid temperature, and only secondarily affected by power level. Therefore, for a particular system configuration, the thermal loss is more a fixed quantity than a fixed percentage. This means that thermal losses have a much larger percentage impact during early morning or late afternoon operation when total incident energy is less.

As with the concentrator subsystems, every attempt was made to use actual heat loss data or to compare PNL-determined thermal losses with other calculated or experimentally derived information. In addition, similar assumptions regarding available receiver material absorptivities, emissivities, and heat transfer coefficients were made. If special selective absorbers were considered for some receiver designs, they were considered for all applicable designs. To better match actual operating conditions, the receiver losses (convection, radiation, and conduction) were included in the simulation code as functions of ambient temperature and wind speed. Also, because thermal losses are not linearly proportional to system operating temperature, calculated thermal loss values were determined by integrating losses along the receiver length, not by selecting some arbitrary average temperature or evaluation point.

3.2.4 Collector Efficiency

The performance of collector systems is often quantified in terms of a single number: the peak or design point collector efficiency, which is equal to the power delivered to the working fluid divided by the incident insolation at peak or design point conditions. This number can be misleading, because many collectors perform well at the design point but have greatly reduced off-design performance. It is also possible to determine an annual average collector performance value that includes the effects of off-design performance. This number is defined as the total energy delivered to the receiver working fluid divided by the total available insolation in a year. The annual average collector efficiency more accurately reflects the performance that could be expected in an actual energy system. PNL estimates of both peak and annual average collector efficiency for each of the concepts appear in Figure 3.1.

The peak and annual average efficiencies point out some interesting characteristics of the collectors. Two-axis tracking systems (Point Focus Central Receiver and Point Focus Distributed Receiver) exhibit the highest annual average performance because of their ability to completely track the sun's motion. The point focus distributed receiver has the best performance of all because it eliminates any cosine losses. Line focus systems have the potential for high design point efficiencies, but suffer in annual average performance because of one-axis tracking.

The information in Figure 3.1 must be used with caution. No single number or small group of numbers can be used to adequately characterize collector performance. The PNL analysis employed a detailed specification of collector performance (see Section 3.6) and a time-step performance simulation (in contrast to average performance values and efficiency trains). The peak and annual average efficiency values in Figure 3.1 are not inputs to the analysis, but results calculated in the performance simulation. They are provided only for relative, qualitative comparisons.

FIGURE 3.1. Collector Efficiency for 300-MWt Plants with 0.4 Solar Fraction

3.3 TRANSPORT SUBSYSTEM

The transport subsystem includes the equipment necessary to transport the working fluid from the central plant to the receivers and back. Transport subsystems were individually tailored for each concept and were extensively optimized with the ETRANS computer code; the exception is the transport subsystem for the 1500⁰F central receiver, which was based on existing designs (Davidson et al. 1978). ETRANS is described in further detail in Appendix A. Components common to all concepts are discussed here; those features which vary within receiver types are presented in the subsections immediately following.

Pipe and insulation were chosen on the basis of cost, operating pressure, temperature, and compatibility with the working fluid. The materials selected for each temperature range are summarized in Table 3.1. Schedule 40 pipe was used throughout, except in the lower sections of the central receiver risers and downcomers; here, the gravity head sometimes necessitated the use of Schedules 80 and 160 pipe. The only pipe and insulation of uncommon design for any concept is the hot-side piping for the 1500⁰F central receiver. This high-temperature piping consists of a temperature-bearing Inconel 617 liner, a layer of Kaowool insulation, and a pressure-bearing carbon steel pipe, and is based on a design proposed by Davidson et al. (1978).

Pipe support spacing and design were based on data from Powell et al. (1974) and Baumeister, Avallone, and Baumeister (1978). U-shaped expansion loops were spaced according to a convenient field dimension (30 to 100 m). The length of each expansion loop was based on tabular values in Powell et al. and adjusted for operating temperature, interloop spacing, and material properties. Pump-motor set specifications were limited to flow rates of 30,000 gpm and pressure increases of 400 psi for reasons of cost and availability; when higher flow or head was required, pumps were used in parallel or series, respectively. Electrical heat tracing was used only on the molten salt transport networks. Flexible hose was used to connect the tracking receivers to the rigid piping networks.

**TABLE 3.1. Working Fluids and Pipe Insulation Materials
for the Temperature Ranges Studied**

Temperature (°F)		Working Fluid	Pipe Material		Insulation Material	
Cold Side	Hot Side		Cold Side	Hot Side	Cold Side	Hot Side
100	250	water/antifreeze	carbon steel	carbon steel	fiber glass	fiber glass
250	450	Caloria	carbon steel	carbon steel	fiber glass	fiber glass
440	575	Caloria	carbon steel	carbon steel	fiber glass	calcium silicate
500	1050	draw salt	carbon steel	stainless steel	fiber glass	calcium silicate
400	1500	air	carbon steel	carbon steel, Inconel 617	fiber glass	kaowool

3.3.1 PFDR and FMDF Transport Subsystems

The layout for dish-shaped collectors shown in Figure 3.2 is based on similar geometries employed by Caputo (1975) and Williams (1978). The piping arrangement illustrated can also be used for staggered fields in which consecutive east-west rows are offset to minimize shading. The field supply and return lines are collinear and are supported above ground. In addition to the field lines, each collector has associated with it a riser and a downcomer (see inset, Figure 3.2). Gate valves on either side of the receiver can be closed for maintenance. A control valve in the riser regulates the flow to maintain a constant receiver exit temperature. The riser and downcomer follow the receiver support struts to minimize shading.

3.3.2 LCNT, LFDR-TR, and LFDR-TC Transport Subsystems

The trough collector layout shown in Figure 3.3 is based upon a network proposed by Kast, Ortiz, and Whitehouse (1979). Although the supply and return lines are once again collinear, both are shown in Figure 3.3 for clarity. In this "fold-over" arrangement, fluid flows through one series of collectors, then through a short connecting piece, and back to the return header through

FIGURE 3.2. Dish Transport Subsystem Layout

FIGURE 3.3. Trough Transport Subsystem Layout

another string of collectors. The number of collectors placed in series is limited by pressure drop constraints; the LCNT receiver pressure drop was so high that only two could be placed in series, greatly increasing the size and cost of the transport subsystem. Valving on the risers and downcomers is identical to that shown in Figure 3.2 for the dish collectors; however, these sections are typically much shorter for trough collectors. Note that a U-shaped connecting piece is required to connect the two strings of collectors together.

3.3.3 PFCR and LFCR Transport Subsystems

The transport subsystems for the central receiver concepts are somewhat simpler than those for the dishes and troughs. The PFCR network consists of a riser and downcomer and smaller-diameter piping within the receiver to distribute the flow to the various receiver panels. Gate valves are placed on either side of the panels to isolate them for maintenance. A control valve in each cold-side distribution pipe regulates the flow to the panels. Gate valves are also located at the base of the riser and downcomer. The substantial flow rates required by some of the larger receivers sometimes necessitated the use of two or more risers or downcomers in parallel. The energy required to pump the fluid up the tower against the force of gravity was assumed recovered with 75 percent efficiency by a head recovery turbine at the base of the downcomer.

The transport subsystem for the LFCR fields follows the design proposed by Di Canio et al. (1979). The majority of the field piping lies within the receivers themselves and thus requires no insulation. The receivers are divided into 200-foot-long sections. Each section can be isolated with gate valves, and a control valve on the inlet side regulates the flow.

3.4 STORAGE SUBSYSTEM

All storage subsystems considered in this study store thermal energy as sensible heat. Latent heat storage and chemical storage were not considered because of the technical difficulty associated with those storage technologies. In this study five types of thermal energy storage were considered: water/ethylene glycol, low temperature oil and rock, intermediate temperature oil and rock, draw salt, and pebble bed.

3.4.1 Water/Ethylene Glycol Storage Subsystem

The water/ethylene glycol storage subsystem is used with the water/ethylene glycol transport subsystem, in which a solution of 50% water and 50% ethylene glycol is heated in the field and returned directly to the thermal energy storage subsystem. A solution of 50% water and 50% ethylene glycol is used to prevent freezing in case of low ambient temperature. The water/ethylene glycol storage subsystem is used by all concepts producing 150°F water.

The water/ethylene glycol storage subsystem uses the water/ethylene glycol solution as the storage medium. The solution is contained in an insulated steel tank. Hot solution is added or removed from the top of the tank; cool oil is added or removed from the bottom of the tank. This maintains the segregation (or thermocline) between the hot and cold solution in the tank.

The thermal storage subsystem does not include heat exchangers for charging storage because the solution is pumped directly from the thermal storage tank to the field and returned directly to the top of the thermal storage tank. The discharge loop and discharge heat exchangers are included in the interface subsystem.

The hot solution temperature in the thermal energy storage tank is 250°F and the cold solution is 100°F, so cold solution is supplied to the field at approximately 100°F and returns at 250°F. Similarly, hot solution is sent to the interface subsystem at 250°F and returns at 100°F.

3.4.2 Oil and Rock Storage Subsystem

The oil and rock storage subsystem is used with the oil transport subsystem in which oil is heated in the field and returned directly to the thermal energy storage subsystem. The low-temperature oil and rock storage subsystem is used when a product temperature of 350°F is required. The intermediate-temperature oil and rock storage subsystem is used when a product temperature of 500°F is required.

The oil and rock storage subsystem uses an oil and rock thermocline storage medium. The oil and rock are contained in an insulated steel tank where a substantial fraction of the volume is filled with inexpensive rock. The

remaining tank volume is filled with more costly oil. Thermal energy is stored as sensible heat in the oil and rock. Hot oil is added or removed from the top of the tank; cool oil is added or removed from the bottom of the tank. This maintains the thermocline between the hot and cold oil in the tank.

The thermal storage subsystem does not include heat exchangers for charging storage because oil is pumped directly from the thermal storage tank to the field and returned directly to the top of the thermal storage tank. The discharge loop and discharge heat exchangers are included in the interface subsystem.

Heat transfer oils tend to degrade at elevated temperatures. Above 580°F the degradation rate for the Caloria HT43 oil used in this study is very high and the oil cannot be successfully used. Below 580°F degradation still occurs but at a substantially reduced rate. The low-temperature oil and rock storage subsystem operates at a temperature low enough to preclude major degradation problems. However, during operation the products of degradation must be removed and replacement oil added (Hallet and Gervais 1977, pp. 4-65).

Two additional components are required to remove the oil degradation residue. The fluid maintenance system filters the oil to remove suspended solids, distills a side stream to remove high-boiling polymeric compounds, and adds fresh makeup fluid to replace decomposed fluid (Hallet and Gervais 1977, pp. 4-85). The ullage maintenance unit, in addition to maintaining an oxygen-free gas above the heat transfer fluid, also must remove the volatile fractions of the products of degradation that evaporate into the ullage space above the heat transfer fluid (pp. 4-66).

The low-temperature oil and rock storage subsystem stores hot oil in the thermal storage tank at 450°F. The cold oil is at 327°F, so cold oil is supplied to the field at 327°F and returns at 450°F. Similarly, hot oil is sent to the interface subsystem at 450°F and returns at 327°F.

The intermediate-temperature oil and rock storage subsystem stores hot oil in the thermal storage tank at 575°F. The cold oil is at 460°F, so cold oil is supplied to the field at 460°F and returns at 575°F. Similarly, hot oil is sent to the interface subsystem at 575°F and returns at 460°F.

3.4.3 Molten Salt Storage

Several attributes of molten salts such as draw salt make them attractive sensible heat storage media. Molten salts can operate at high temperature without decomposition or high vapor pressure. In addition, a molten salt storage subsystem can be combined with a molten salt transport subsystem. This combination would eliminate the storage charging heaters and the resulting temperature drop.

Molten salt storage subsystems also have several disadvantages. First, molten salts freeze at temperatures well above ambient. Second, they are incompatible with carbon steel at high temperatures. Third, molten salts are more expensive than other sensible heat storage media.

The molten salt subsystem considered in this study uses draw salt with a maximum storage temperature of 1050°F. Due to the chemical properties of draw salt at 1050°F, the molten salt storage subsystem must use stainless steel for all high-temperature components. The draw salt is contained in an insulated tank, with the inlets and outlets arranged to form a thermocline between the hot and cold salt.

The thermal storage subsystem does not include heat exchangers for charging storage because molten salt is pumped directly from the thermal storage tank to the field and returned directly to the top of the thermal storage tank. The discharge loop and discharge heat exchangers are included in the interface subsystem.

Because the degradation rate of molten salts such as draw salt is low at storage system operating temperatures, a fluid maintenance unit is not required. The ullage maintenance unit is still required to maintain an inert gas cover over the heat transfer molten salt in the storage tank. Provisions for heat tracing of pipes and storage tanks to prevent the freezing of the molten salt during long outages are included.

Hot molten salt in the thermal storage tank is maintained at 1050°F and the cold molten salt is maintained at 500°F, so cold molten salt is supplied to the field at 500°F and returns at 1050°F. Similarly, hot molten salt at 1050°F is supplied to the interface subsystem and returns at 500°F.

3.4.4 Pebble Bed Storage

The pebble bed thermal storage subsystem is used for energy storage when a product temperature of 1500°F is considered. Since the PFCR is the only collector concept used at 1500°F, only one application of the pebble bed thermal storage subsystem was considered.

The pebble bed thermal storage subsystem consists of a pressure vessel containing a bed of pebbles. To charge storage hot air from the receiver is blown through the pebble bed, transferring heat to the pebbles. To discharge storage air from the load is blown through the pebble bed and heated. The maximum exit temperature of air during discharge is 1490°F. The pebbles are assumed to be made of denstone, a material commonly used at these temperatures. The pressure vessel is assumed to be a prestressed concrete pressure vessel. The design of the pebble bed thermal storage unit is based on designs developed for application with compressed air energy storage.

3.5 INTERFACE SUBSYSTEM

The interface subsystems are used to transfer thermal energy from the working fluid (fluid from collectors) to the process fluid (fluid provided to user). Interface subsystems are required for all but the 1500°F case, in which the air working fluid is provided directly to the user. For all cases the interface subsystem comprises a heat exchanger, circulating pump, piping, and valves. Only the equipment necessary to circulate the working fluid from the storage subsystem to the heat exchanger was characterized in this study. Equipment on the user side of the heat exchangers, which would be required with or without a solar system, was not included. Heat exchanger conceptual designs used in the interface subsystems were prepared by Harris Thermal Transfer Products, Inc. (Adamski 1981).

3.5.1 Water - Water/Ethylene Glycol Interface Subsystem

With this interface subsystem the user is supplied with a process fluid of 150°F hot water. The working fluid is a mixture of water and ethylene glycol at 250°F. Energy is transferred from the working fluid to the process

fluid in a carbon steel shell and tube heat exchanger. Single shell units, of increasing size, are used for the 50-, 150-, and 300-MWt plant sizes. At 600-MWt, two 300-MWt units are used in parallel.

3.5.2 Water/Steam - Oil Interface Subsystem

This subsystem is used at two process temperatures. In the low-temperature case, oil working fluid at 450°F is used to generate saturated steam process fluid at 350°F. In the intermediate-temperature case, oil working fluid at 575°F is used to generate saturated steam process fluid at 500°F. Both cases use a recirculating fluid configuration in which water is vaporized in the heat exchangers and separated from the moisture in a steam drum. The basic heat exchanger module consists of two shell and tube exchangers in series connected to a steam drum and a recirculation pump. Approximately 10% of the shell side fluid is removed as blowdown in the steam drum, treated, and recirculated through the exchangers to minimize fouling. The exchangers and drum are made of carbon steel. One basic heat exchanger module of two shells and one steam drum is used for the 50-MWt plants. Three, six, and twelve of these basic modules are used in parallel for the 150-, 300-, and 600-MWt plants, respectively.

3.5.3 Air - Molten Salt Interface Subsystem

This subsystem is used in plant configurations in which the process fluid is air at 1000°F. The working fluid is molten salt at 1050°F. The basic heat exchanger module consists of four stainless steel shell and tube exchangers in series. One basic heat exchanger module of four shells is used for the 50-MWt plants. Three, six, and twelve of these basic modules are used in parallel for the 150-, 300-, and 600-MWt plants, respectively.

3.5.4 Summary of Interface Subsystems

Table 3.2 summarizes the key design parameters for each of the interface subsystem heat exchangers.

TABLE 3.2. Description of Interface Subsystems

	Interface Subsystems by Process Temperature			
	<u>150°F</u>	<u>350°F</u>	<u>500°F</u>	<u>1000°F</u>
Process fluid (shell side)	water	water/steam	water/steam	air
T_{in}/T_{out} (F)	68/150	180/350	180/500	400/1000
P_{in}/P_{out} (psia)	110/100	120.3/120.0	666.3/666.1	125/100
Working fluid (tube side)	water/ ethylene glycol	oil	oil	molten salt
T_{in}/T_{out} (F)	250/100	450/329	575/462	1050/500
P_{in}/P_{out} (psia)	105/100	115/100	110/100	120/100
Total heat transfer area (1000 ft ²)				
50 MWt	15	116	139	49
150 MWt	43	347	416	148
300 MWt	86	694	832	297
600 MWt	172	1387	1663	593

3.6 SUMMARY OF KEY PERFORMANCE PARAMETERS

The SOLSTEP-IPH performance simulation used in this study modeled four major component subsystems: the collector (concentrator and receiver), energy transport, energy storage, and interface subsystems. Each of these subsystems was characterized by several performance parameters, which are briefly discussed here and summarized in Table 3.3. Values for each parameter were developed for each concept considered in this study.

Several parameters were used to characterize the collector subsystem. Every generic concept used the normal direct insolation striking the collector field. In addition, the Low Concentration Nontracking concept used a fraction of the diffuse insolation. A geometric optics efficiency for the concentrator field was used to quantify the shading, blocking, and cosine losses experienced by the field. The geometric optics were considered as a variable function of the solar altitude and azimuth angles. Other parameters used to characterize the concentrator included the surface optical efficiency (reflectivity for mirrors) and an average surface degradation factor. The energy transfer efficiency from the concentrator to the receiver was quantified by two parameters. The concentrator-receiver interception factor accounted for tracking and spillage errors and was treated as a variable function of wind speed. The second parameter was an average value for the atmospheric attenuation in the collector field. Receiver thermal performance was modeled by two parameters: absorptivity, and a receiver thermal loss term. The thermal loss parameter was treated as a variable function of ambient air temperature and wind speed.

The energy transport subsystem was characterized by several parameters, all expressed as a function of field size. The first term is the transport system thermal efficiency. The next two are the average daily energy requirements for warmup of the transport system to operating temperature and for the night-time heat trace operation.

The energy storage subsystem was modeled by two parameters. The first term specified the storage energy loss with time. Another limited the maximum storage drawdown by setting a minimum allowable storage charge.

TABLE 3.3. Summary of Key Performance Parameters

Performance Parameters	PFCR				
	150°F	350°F	500°F	1000°F	1500°F
Input Parameters					
Fraction of direct insolation	1.0	1.0	1.0	1.0	1.0
Fraction of diffuse insolation	0.0	0.0	0.0	0.0	0.0
Peak geometric optics efficiency ^(a)	0.80	0.80	0.80	0.80	0.80
Surface optical efficiency	0.92	0.92	0.92	0.92	0.92
Surface degradation factor	0.95	0.95	0.95	0.95	0.95
Concentrator-receiver intercept factor	0.99-0.98	0.99-0.98	0.99-0.98	0.99-0.98	0.99-0.98
Atmospheric attenuation factor ^(b)	0.98-0.89	0.98-0.89	0.98-0.89	0.98-0.88	0.98-0.88
Receiver absorptivity	0.85	0.85	0.85	0.95	0.95
Receiver thermal loss (kW/m ²) ^(c)	0.004	0.008	0.012	0.026	0.085
Field sizes (thousand m ²)	60-3500	60-3600	60-3600	60-3800	80-4800
Transport thermal efficiency	1.0	0.99	0.99	0.99	0.98-0.97
Transport pump power rating (MW)	0.1-9.1	0.2-10.0	0.2-22.0	0.08-5.4	0.80-175.0
Transport warmup energy req. (MW/hr)	0.1-2.3	0.3-11.0	0.5-25.0	0.5-20.0	1.1-340.0
Transport heat trace energy req. (MW/hr)	--	--	--	0.06-0.03	--
Storage sizes (hr)	0-18	0-18	0-18	0-18	0-18
Storage output pump power rating (kW)	10-118	58-734	41-520	13-167	--
Storage energy loss rate (%/hr)	0.03-0.02	0.11-0.08	0.16-0.10	0.13-0.05	0.06-0.03
Interface standby energy requirement (kW)	2-13	16-290	23-380	24-312	--
Calculated Parameters					
Annual purchased energy (10 ⁶ kWh)	0.05-58.0	0.5-65.0	0.05-145.0	0.2-34.0	1.1-960.0
Peak field efficiency	0.64	0.63	0.63	0.61	0.55
Annual average field efficiency	0.53-0.45	0.52-0.45	0.51-0.44	0.49-0.42	0.40-0.34
Annual average transport efficiency	1.0-0.98	0.99-0.98	0.99-0.95	0.99	0.99-0.55
Annual average storage efficiency	1.0-0.99	1.0-0.98	1.0-0.95	1.0-0.97	1.0-0.99
Annual average system efficiency	0.53-0.42	0.52-0.41	0.51-0.38	0.49-0.38	0.40-0.18

(a) Peak efficiency values may occur at different times for each concept.

(b) These are the maximum values of atmospheric attenuation.

(c) Losses are expressed in units of kW/m² of collector aperture area.

Table 3.3. (continued)

PFDR				FMDF			
150°F	350°F	500°F	1000°F	150°F	350°F	500°F	1000°F
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.0	1.0	1.0	1.0	0.97	0.97	0.97	0.97
0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
0.90	0.90	0.90	0.90	0.93	0.93	0.93	0.93
1.0	1.0	1.0	1.0	0.99	0.99	0.99	0.99
0.96	0.96	0.96	0.96	0.86	0.86	0.86	0.86
0.001	0.002	0.003	0.012	0.004	0.014	0.022	0.049
50-2400	50-2600	50-2700	60-3000	70-3700	80-4000	80-4400	90-5000
0.99-0.98	0.95	0.92-0.91	0.86	0.99	0.98	0.97	0.96-0.95
0.1-13.0	0.4-40.0	0.4-58.0	0.2-10.0	0.1-12.0	0.5-39.0	0.58-53.0	0.15-10.0
1.5-100.0	3.3-270.0	4.5-410.0	4.5-430.0	0.9-55.0	2.6-170.0	3.8-300.0	2.5-380.0
--	--	--	24-1150	--	--	--	5.3-220.0
0-18	0-18	0-18	0-18	0-18	0-18	0-18	0-18
10-118	58-734	41-520	13-167	10-118	58-734	41-520	13-167
0.03-0.02	0.11-0.08	0.16-0.10	0.13-0.05	0.03-0.02	0.11-0.08	0.16-0.10	0.13-0.05
2-13	16-290	23-380	24-312	2-13	16-290	23-380	24-312
0.1-86.0	0.2-280.0	0.2-382.0	8.0-430.0	0.1-75.0	0.5-250.0	0.2-340.0	3.0-140.0
0.77	0.77	0.76	0.75	0.69	0.67	0.66	0.63
0.67	0.67	0.66	0.65	0.44	0.41	0.40	0.36
0.99-0.96	0.95-0.86	0.92-0.80	0.75-0.74	0.99-0.98	0.98-0.90	0.97-0.86	0.92-0.91
1.0-0.99	1.0-0.96	1.0-0.95	1.0-0.97	1.0-0.99	1.0-0.96	1.0-0.95	1.0-0.97
0.66-0.59	0.63-0.52	0.60-0.48	0.48-0.43	0.44-0.39	0.39-0.33	0.38-0.30	0.33-0.28

TABLE 3.3. (continued)

Performance Parameters	LFCR			
	150°F	350°F	500°F	1000°F
Input Parameters				
Fraction of direct insolation	1.0	1.0	1.0	1.0
Fraction of diffuse insolation	0.0	0.0	0.0	0.0
Peak geometric optics efficiency ^(a)	0.86-0.89	0.86-0.89	0.86-0.89	0.86-0.89
Surface optical efficiency	0.92	0.92	0.92	0.92
Surface degradation factor	0.95	0.95	0.95	0.95
Concentrator-receiver intercept factor	1.0	1.0	1.0	1.0
Atmospheric attenuation factor ^(b)	0.99	0.99	0.99	0.99
Receiver absorptivity	0.96	0.96	0.96	0.96
Receiver thermal loss (kW/m ²) ^(c)	0.003	0.011	0.018	0.040
Field sizes (thousand m ²)	80-3600	80-3800	90-4000	90-4300
Transport thermal efficiency	0.99	0.99	0.99-0.98	0.98-0.97
Transport pump power rating (MW)	0.17-12.0	0.3-27.0	0.4-41.0	0.15-9.0
Transport warmup energy requirement (MW/hr)	0.70-42.0	2.0-131.0	3.5-240.0	3.0-325.0
Transport heat trace energy requirement (MW/hr)	--	--	--	0.15-37.0
Storage sizes (hrs)	0-18	0-18	0-18	0-18
Storage output pump power rating (kW)	10-118	58-734	41-520	13-167
Storage energy loss (%/hr)	0.03-0.02	0.11-0.08	0.16-0.10	0.13-0.05
Interface standby energy requirement (kW)	2-13	16-290	23-380	24-312
Calculated Parameters				
Annual purchased energy (10 ⁶ kWhr)	0.3-73.0	0.5-165.0	0.3-250.0	0.2-71.0
Peak field efficiency	0.72	0.71	0.70	0.67
Annual average field efficiency	0.39-0.43	0.38-0.42	0.36-0.40	0.34-0.37
Annual average transport efficiency	0.99-0.97	0.98-0.94	0.98-0.90	0.98-0.95
Annual average storage efficiency	1.0-0.99	1.0-0.96	1.0-0.90	1.0-0.97
Annual average system efficiency	0.38-0.40	0.36-0.37	0.35-0.34	0.33

(a) Peak efficiency values may occur at different times for each concept.

(b) These are the maximum values of atmospheric attenuation.

(c) Losses are expressed in units of kW/m² of collector aperture area.

TABLE 3.3. (continued)

LFDR-TR				LFDR-TC			LCNT	
150°F	350°F	500°F	1000°F	150°F	350°F	500°F	150°F	350°F
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.25	0.25
0.82	0.82	0.82	0.82	1.0	1.0	1.0	1.0	1.0
0.81	0.81	0.81	0.81	0.85	0.85	0.85	0.79	0.79
0.92	0.92	0.92	0.92	0.94	0.94	0.94	0.98	0.98
0.98	0.98	0.98	0.98	0.98	0.98	0.98	1.0	1.0
1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0.90	0.90	0.90	0.90	0.92	0.92	0.92	0.93	0.93
0.007	0.023	0.039	0.104	0.013	0.046	0.077	0.019	0.083
80-4000	90-4500	100-5000	140-6800	60-3600	70-4500	80-5000	70-3400	90-4400
0.99	0.99	0.99-0.98	0.98-0.97	0.99	0.99	0.99-0.98	0.97	0.90
0.12-13.0	0.41-43.0	0.60-31.0	0.17-11.0	0.1-16.0	0.37-54.0	0.50-41.0	0.14-15.0	0.96-57.0
0.42-28.0	1.4-99.0	2.7-230.0	3.2-390.0	0.4-35.0	1.3-137.0	2.5-310.0	4.0-220.0	9.3-660.0
--	--	--	2.3-79.0	--	--	--	--	--
0-18	0-18	0-18	0-18	0-18	0-18	0-18	0-18	0-18
10-118	58-734	41-520	13-167	10-118	58-734	41-520	10-118	58-734
0.03-0.02	0.11-0.08	0.16-0.10	0.13-0.05	0.03-0.02	0.11-0.08	0.16-0.10	0.03-0.02	0.11-0.08
2-13	16-290	23-380	24-312	2-13	16-290	23-380	2-13	16-290
0.2-81.0	0.5-270.0	1.5-200.0	1.3-80.0	0.3-100.0	0.2-340.0	1.3-240.0	0.2-95.0	1.5-360.0
0.54	0.52	0.49	0.41	0.69	0.64	0.59	0.69	0.63
0.39	0.35	0.32	0.23	0.52	0.44	0.38	0.45	0.38
1.0-0.97	1.0-0.90	0.96-0.91	0.96-0.94	1.0-0.96	1.0-0.88	0.97-0.90	0.97-0.94	0.89-0.79
1.0-0.99	1.0-0.97	1.0-0.95	1.0-0.96	1.0-0.99	1.0-0.95	0.97-0.93	1.0-0.99	1.0-0.97
0.39-0.36	0.35-0.30	0.30-0.28	0.22-0.21	0.52-0.40	0.43-0.29	0.36-0.29	0.43-0.41	0.33-0.29

Two auxiliary loads were considered, the field circulation pump and the storage output pump. In each case the installed capacity for the auxiliary load was varied with plant size, field size, and storage size, as appropriate. Actual pumping energy requirements accounted for part-load operation whenever applicable.

The preceding discussion has briefly explained the parameters used to characterize the performance of the generic concepts. It is not practical to include all of the input data used in the analysis in this report; however, Table 3.3 summarizes some of the major variables. A range of values indicates a variation with plant size, field size, or storage size. For parameters that were treated as variable functions, a nominal value is given.

4.0 ESTIMATION OF COSTS

The overall objective of the cost estimation task is to provide an economic comparison of the alternative solar thermal industrial process heat concepts for a variety of plant configurations and operating conditions. The evaluation of concepts in this study has been performed on a consistent and equitable basis. Consistency in the evaluation process has been maintained by utilizing a standardized set of ground rules, assumptions, unit costs, and methodologies in the assessment of each concept. Ensuring equitability in the evaluation process is more difficult, since methodologies and unit costs that favor one concept may put other concepts at a relative disadvantage. In determining an equitable basis for the evaluation, cost estimates were based on mass-produced components, representative of the long-term potential of a given concept. This approach is necessary to determine which concepts will ultimately have the best economic performance. All the concepts analyzed are in somewhat different states of development. Taking the long-term view neglects these differences.

The objective of the economic analysis is to compare the solar concepts to each other. The cost estimates in this report have not been generated to compare the viability of solar industrial process heat to conventional energy sources. Estimates of levelized energy cost (LEC) are life-cycle costs and not directly comparable to current energy costs. Estimates of LEC are strongly affected by economic and financial assumptions, so that a comparison of LECs between a conventional energy source and solar energy must be performed with exactly the same parameters and methodologies to be meaningful. In general, the cost estimates and results of the economic analysis in this report should not be indiscriminately used in making predictions of the overall economic attractiveness of solar industrial process heat. Other factors in addition to LEC determine the worth of the system to the user. Examples of these factors include the operating characteristics of the system, environmental impacts, and the availability of conventional fuels. The analysis of these characteristics was beyond the scope of this study.

Because each concept is analyzed at a variety of collector field sizes, storage sizes, temperatures and capacities, a very large number of cost estimates is required. To generate these estimates expediently, costs were estimated for each plant cost account at a number of specific design points. The estimated costs at the plant design points were then used to develop a cost estimate scaling relation (CESR) for each cost account. The CESRs serve to scale the design point cost estimates as a function of parameters such as collector field size and plant power level. The use of CESRs allowed a large number of plant configurations to be analyzed using the SOLSTEP-IPH code, as described in Appendices A and C.

A great deal of component cost information is required to estimate costs for solar concepts. Components range in complexity from off-the-shelf items such as carbon steel pipe, to nonstandard components such as the foundation and tower required for the PFCR concept. A number of sources were used to assess component costs, including contact with vendors, in-house cost data bases, results from previous PNL solar studies, and results from studies performed by other organizations. Where results from other studies were utilized, careful interpretation of the studies' ground rules and assumptions was required to maintain consistency with other cost data used in this study. All component costs and LECs reported in this study are expressed in mid-year 1980 dollars.

The cost estimates reported here are considered to be reasonable estimates for the technologies, given the ground rules and assumptions that are used. A generally conservative approach has been used in estimating component costs. Because the normal tendency in estimating costs of new technologies from conceptual designs is to underestimate rather than overestimate, the conservative approach is felt to be best for a reasonable overall estimate of the cost.

4.1 ECONOMIC GROUND RULES AND ASSUMPTIONS

Standardized ground rules and assumptions are very important in generating normalized cost estimates for alternative solar concepts. Minor changes in these inputs can cause large changes in estimates of both individual component costs and the overall levelized energy cost for the plant.

Among the most important assumptions and ground rules that affect component cost estimates are those that relate to the assumed industry maturity levels and production rates for items currently not being mass produced, such as collectors. In general, costs for items produced by a mature, established industry are lower than those for identical items produced by a developing industry. Similarly, an item's cost tends to decrease as production rate increases. These trends result from factors such as improvements in manufacturing techniques and economies of scale in materials, labor, and capital investments.

All component cost estimates for this study were developed on the assumption that a commercial solar industry had existed for several years. This assumption avoids burdening concepts with one-time development costs; the resulting costs are representative of a stabilized, competitive market. Collector costs were assessed based on the assumption that several million square meters of collector area were being produced each year in a single manufacturing facility. For the PFCR concept, this is equivalent to a production rate in the neighborhood of 50,000 to 75,000 heliostats per year.

General financial and economic assumptions regarding the solar IPH system user do not affect estimates of component costs but are strong determinants of levelized energy cost (LEC). Examples of these assumptions are escalation rates, financing assumptions, the cost of capital, and the fixed charge rate. Because these parameters have a major effect on LEC, it is important to have a standardized set of assumptions used in comparison of concepts. The values used for these parameters were based on the recommendations of the DOE Cost Goals Committee at the time of the analysis. The parameter values are felt to represent a conservative case for the adoption of solar industrial process heat systems in the 1995 time frame.

A summary of the principal economic ground rules and assumptions used in this study is shown in Table 4.1.

TABLE 4.1. Economic Ground Rules and Assumptions

<u>Category</u>	<u>Ground Rules and Assumptions</u>
Solar Industry	<p>Capital investment costs for solar collectors are estimated assuming sophisticated fabrication, assembly, construction, and installation techniques.</p> <p>R&D costs, development subsidies, and all other costs associated with commercialization of the solar industry are not included.</p> <p>Technological and economic risk as they may affect investments by the solar industry are not considered.</p> <p>Potential decommissioning costs and salvage values of the solar industrial process heat plant are not considered.</p>
Collector Manufacturing	<p>Collector costs are estimated assuming large-volume commercial production of collectors.</p> <p>Collector manufacturing facilities are assumed to consist of highly automated processes, thereby minimizing production labor. Manufacturing process technology is assumed to be current state-of-the-art.</p> <p>Collector cost estimates include manufacturing facility indirect costs, overhead, and allowances for a required return investment. Allowances for sales taxes, working capital, and manufacturing facility personnel training are also included.</p>
Solar IPH Plant Operation and Maintenance	<p>Unscheduled maintenance requirements are assumed to be minimal.</p> <p>Concentrator cleaning is performed monthly.</p> <p>Operators are required for plant operations, and are present whenever the plant is operating.</p> <p>Plant control schemes are highly automated, requiring plant operators to perform primarily a monitoring function.</p> <p>All required maintenance is performed using an in-house maintenance crew.</p> <p>Electric energy for plant operation is purchased at a cost of \$0.043/kWh (1980 price level, 1980 dollars)</p>

TABLE 4.1. (continued)

<u>Category</u>	<u>Ground Rules and Assumptions</u>
IPH Owner Financial Parameters	Required rate of return on equity = 0.19
	Capital recovery factor = 0.196
	Equity fraction = 100%
	Effective tax rate = 0.48
	Investment tax credit = 0.10
	Plant service life = 20 years
	Plant tax life = 16 years
	Property taxes and insurance = 0.02
	Fixed charge rate = .282
Economic Inputs	Levelized energy costs are calculated using methodologies described in Doane et al. (1976)
	Plant construction and startup periods are assumed to be 4 years.
	Capital cost escalation rate, 1980-1995 = 0.08
	Capital cost escalation rate, 1995-2015 = 0.06
	O&M cost escalation rate, 1980-1995 = 0.10
	O&M cost escalation rate, 1995-2015 = 0.08
	Electric energy cost escalation rate, 1980-1995 = 0.11
	Electric energy cost escalation rate, 1995-2015 = 0.08
	First year of plant operation: 1995
	Base year price levels: 1980

4.2 CAPITAL INVESTMENT COST ESTIMATING

Capital investment costs include all costs incurred during plant construction and represent the major expenditures for solar industrial process heat plants. Capital investment costs are reported in six categories: collector, energy transport, energy conversion, energy storage, balance of plant, and indirect and contingency. Each category contains aggregated costs of a number of components, which are discussed in subsequent sections.

The methodology used to estimate capital costs depends on the commercial availability of the component. Costs for off-the-shelf items were estimated based on current unit cost information. Cost estimates for less conventional items required analysis of the impact of increased production and technological improvements. Where possible, component costs were estimated independently of other studies, but in some cases component costs were derived from estimates available in other studies. Using estimates from previous studies required the utmost care in interpreting the studies' methodology and results to ensure consistency with PNL estimates.

4.2.1 Collector Subsystem Costs

The collector subsystem, which includes both the concentrator and receiver, is the major cost contributor for all concepts. The collector subsystem often accounts for over 50% of the levelized energy cost. Each concept is characterized by a single concentrator design, while the receiver design varies with operating temperature. As the plant capacity changes, the size of the receiver and the amount of concentrator surface vary, but their design remains constant.

Previous studies at PNL (Laity et al. 1979 and Apley et al. 1980) included detailed analyses of generic collector subsystem designs and costs. Independent cost estimates were made based on a comparative analysis of manufacturing and field installation tasks for each collector concept. Consistent assumptions, ground rules, unit labor and material costs, and cost estimating methodologies were used. This approach resulted in cost estimates for collector subsystems that are consistent, which allows an equitable comparison between concepts.

The results of the previous PNL studies were used as the basis for the cost estimates developed for this project. The results were updated through a review of current information. Proponents of each concept were contacted, and the collector subsystem designs and costs were modified where appropriate. Collector costs taken from Apley et al. (1980) and Laity et al (1979) were modified based on the following factors:

- re-evaluation of designs based on recently acquired data from proponents and technical literature
- re-evaluation of manufacturing and installation costs based on recently acquired data from proponents and technical literature
- allowance for extreme material price changes relative to general inflation
- allowance for general inflation from mid-1978 to mid-1980 price levels.

Five different operating temperatures were considered for the receivers. Only the PFCR concept was considered practical for the full range of conditions. Other concepts were considered at either two, three, or four operating temperatures for a total of 26 combinations of concept and operating temperature. Detailed designs and cost estimates were developed at each concept's baseline condition, which corresponded to the highest operating temperature for each concept.

The concentrator for each concept does not change for different receiver operating conditions. Receiver cost estimates for lower operating temperatures were based on the following potential design changes.

- Receiver tube size was varied to maintain adequate heat transfer between the tube and the working fluid.
- Tube material was allowed to change so that less expensive materials could be used.

The PFCR concept required a different approach for estimating the receiver cost because of the fundamentally different designs required over its range of operating temperatures. Three baseline designs were costed, which covered the

1500°F, 1000°F, and 500°F design points. Costs for the 350°F and 150°F systems were estimated from the 500°F baseline case and considered the potential design changes just described.

Costs for PFCR receiver absorbers and towers are presented in Figures 4.1 and 4.2. Absorber costs increase with temperature above 500°F because the higher temperatures require more expensive materials. The 1500°F absorber suffers an additional cost penalty because of the larger heat transfer area required for air absorbers compared to the other receiver designs, which use liquids for a heat transfer fluid. The size and weight of 150°F, 350°F, 500°F, and 1000°F absorbers are similar enough to allow the use of a single cost function for the tower in these systems. The 1500°F (air) absorber is larger and heavier, and hence requires a more expensive tower. A summary of collector costs estimated for this solar thermal process heat analysis is shown in Table 4.2.

TABLE 4.2. Collector Subsystem Costs

Concept	Concentrator Costs (1980 \$/m ² of concentrator area)	Receiver Costs (1980 \$/m ² of concentrator area)		
		150,350,500°F	1000°F	1500°F
PFCR	94	15-46	17-50	31-59
PFDR	123	15	29	
FMDF	82	24	29	
LFDR	71	59	67	
LFDR-TR	78	26	31	
LFDR-TC	69	11		
LCNT	86	46

FIGURE 4.1. Central Receiver Absorber Costs

FIGURE 4.2. Central Receiver Tower Costs

4.2.2 Transport Subsystem Costs

Energy transport subsystems employ either water/ethylene glycol, heat transfer oil, molten salt, or air as the thermal energy transfer fluid. The transport medium always matches both the collector and storage fluid for any concept; therefore, no heat exchangers are required. The transport subsystem includes all piping connecting the collector and storage subsystems. The specific cost components of the transport subsystems are pipe, insulation, valves, fittings, pumps, expansion loops, and pipe supports plus labor expenses involved with installation.

A unit cost data base was assembled for a large range of sizes and materials for each transport component. Prices, labor wages, and labor productivity rates were obtained from quite a few sources, including previous solar thermal reports, cost estimating manuals, construction cost estimating guides, and contact with vendors. The development of a standardized cost data base was an important step in ensuring comparative transport costs among concepts.

ETRANS, a piping network optimization code, was developed by PNL (Barnhart 1980) to assist in the design and costing of solar thermal transport subsystems. The code optimizes pipe diameter and insulation thickness for sections of the transport field based on the cost data base described above, pumping energy costs, heat loss energy costs, and heat tracing energy costs, where required. Costs for a given transport system are then tabulated based on the section-by-section, optimally selected design. A more thorough description of the optimization procedure is given in Appendix A or in the PNL report by Barnhart.

ETRANS was used to design and cost the transport subsystem for each of the seven concepts at all operating conditions except for the PFCR concept at 1500⁰F. Design and cost calculations for this 1500⁰F air transport subsystem were completed separately.

Transport subsystems were designed for operating temperatures of 150, 450, 575, 1050, and 1500⁰F for use with the 150, 350, 500, 1000, and 1500⁰F systems, respectively. For each temperature, designs and costs were developed for 50-, 700-, and 2800-MWt capacities. These three data points were used to

formulate the cost estimating scaling relationships (CESRs) for each transport subsystem. The wide range of thermal capacities was required to cover the wide range of plant sizes from 50-MWt plants with no storage to 600-MWt plants with 18 hours of storage. Table 4.3 summarizes the transport subsystem costs developed for this analysis.

TABLE 4.3. Transport Subsystem Costs

<u>Concept</u>	Transport Costs by Product Temperature (1980 \$/m ² of concentrator area)				
	<u>150°F</u>	<u>350°F</u>	<u>500°F</u>	<u>1000°F</u>	<u>1500°F</u>
PFCR					
50 MWt	1.4	2.4	2.4	1.9	13
700	0.9	1.7	2.1	2.0	17
2800	1.4	3.0	3.3	2.7	12
PFDR					
50	53	59	65	88	
700	51	60	65	89	
2800	54	65	72	99	
FMDf					
50	9	11	12	15	
700	8	12	14	17	
2800	10	17	19	24	
LFCR					
50	5	7	8	8	
700	5	10	10	12	
2800	7	13	14	19	
LFDR-TR					
50	5	8	8	8	
700	6	10	13	11	
2800	8	14	17	19	
LFDR-TC					
50	6	8	9		
700	7	12	15		
2800	10	19	20		
LCNT					
50	120	128			
700	122	135			
2800	125	144			

In general, transport subsystem costs for central receiver concepts tended to be lower than those for distributed receiver systems. Transport costs for the two Line Focus Distributed Receiver concepts were reasonable because these collectors can be ganged together in long rows, allowing the receiver tubes to replace much of the transport piping. Because of high pressure drop, the LCNT collectors cannot be extensively ganged, and the estimated transport cost for this system was correspondingly high.

The transport subsystem costs for the PFCR concept exhibit two interesting trends. For temperatures up to 500°F the cost on a $\$/m^2$ basis increased from 50 to 700 MWt and decreased from 700 to 2800 MWt. The economy of scale between the lower two power levels is caused by the nonproportionality of tower height to field size; that is, the tower for a field that is twice as large is not twice as high. This economy of scale is negated at the highest power level because the transport requirements are so large that several parallel runs of pipe are required. The 1500°F PFCR transport costs exhibit a different type of behavior, caused by the large flow areas required to transport air. Design velocities of 100 ft/sec were assumed at 50 and 700 MWt. At 2800 MWt this design velocity led to an impractical number of parallel piping runs. The design velocity was increased to 200 ft/sec, which allowed a less expensive transport subsystem (on a $\$/m^2$ basis) but greatly increased the required pumping power.

4.2.3 Storage Subsystem Costs

Energy storage subsystem costs were estimated with the assumption that the storage technologies have been demonstrated and are commercially available. Because the majority of storage system equipment is conventional, commercially available hardware, this assumption is thought to be valid. Costs of this equipment will not likely be significantly affected by commercial development of energy storage technologies.

Capital costs were estimated for five storage designs: 1) water and ethylene glycol (250°F), 2) heat transfer oil and rock (450°F), 3) heat transfer oil and rock (575°F), 4) draw salt (1050°F), and 5) air and rock (1500°F). These five designs were used for systems producing process fluids at 150, 350,

500, 1000, and 1500⁰F, respectively. Storage subsystem cost estimates were developed by aggregating conventional component costs obtained from vendor quotes, cost estimating guides, and technical reports. Basically, each storage subsystem consists of an insulated containment vessel and the storage medium. Auxiliary components included tank insulation and containment dikes. The cost of associated piping, valves and pumps are included in the interface subsystem cost account. Component costs were estimated at four thermal power levels (50, 150, 300 and 600 MWt) and at four storage capacities (3, 6, 9 and 18 hours) for a total of 16 design point cost estimates for each storage technology. All equipment costs were estimated on an installed basis using 1980 price levels.

The capital costs of the storage systems are directly proportional to the storage capacity (kWh) and are inversely proportional to both the heat capacity of the storage medium and the temperature difference across the thermocline. The storage system costs are also a function of the maximum storage temperature and pressure because these design considerations dictate the material requirements for system components. With all designs, the cost of the storage medium was found to dominate all other costs; therefore, in order to significantly reduce storage system costs, it will be necessary to identify cheaper storage media or reduce the cost of producing the media. The following subsections discuss the capital costing of each storage design in more detail. A comparison of the relative magnitudes of component costs for each storage concept at a single design point (300 MWt, nine hours storage) is presented in Figure 4.3. Table 4.4 presents a summary of the total storage subsystem costs.

Water and Ethylene Glycol Thermal Storage Costs

Costs for storage systems using water and ethylene glycol as the storage medium include the costs of carbon steel tanks, external calcium silicate insulation, earthen containment dikes, demineralized water, and ethylene glycol.

The cost of the storage medium was determined by multiplying the unit cost of ethylene glycol and demineralized water by their respective volume requirements. A cost of \$0.35/lb (Chem. Mkt. Rep. 1980) was assumed for ethylene

FIGURE 4.3. Sample Storage Component Costs (300-MWt, 9 hours storage)

Table 4.4. Storage Subsystem Costs

<u>Storage Subsystems</u>	<u>Storage Subsystem Costs (1980 \$/kWh)</u>			
	<u>3 hour</u>	<u>6 hour</u>	<u>9 hour</u>	<u>18 hour</u>
<u>150°F Systems</u> <u>(250°F Water/Ethylene Glycol)</u>				
50 MWt	6.72	6.27	6.11	5.92
150	6.11	5.92	5.88	5.78
300	5.92	5.83	5.78	5.78
600	5.83	5.78	5.78	5.78
<u>350°F Systems</u> <u>(450°F Oil/Rock)</u>				
50 MWt	6.58	5.99	5.71	5.28
150	5.71	5.28	5.09	4.95
300	5.28	4.95	4.95	4.95
600	4.95	4.95	4.95	4.95
<u>500°F Systems</u> <u>(575°F Oil/Rock)</u>				
50 MWt	6.96	6.38	6.13	5.63
150	6.13	5.63	5.42	5.28
300	5.63	5.28	5.28	5.28
600	5.28	5.28	5.28	5.28
<u>1000°F Systems</u> <u>(1050°F Draw Salt)</u>				
50 MWt	5.02	4.33	4.14	3.69
150	4.14	3.69	3.64	3.38
300	3.69	3.51	3.28	3.20
600	3.51	3.30	3.20	3.07
<u>1500°F Systems</u> <u>(1500°F Air/Rock)</u>				
50 MWt	7.65	7.63	7.60	7.60
150	7.60	7.60	7.59	7.59
300	7.60	7.59	7.59	7.60
600	7.59	7.60	7.60	7.61

glycol. It was estimated that distilled water could be produced onsite for about \$1.50/gal. Transportation and ullage costs were included in the overall cost of the storage medium. Tank costs were estimated using Guthrie (1974) cost estimating methodology. That is, the base tank cost, derived from Guthrie relationships, was multiplied by a material and labor factor that accounts for the cost of installation labor and additional materials used to interface the tank with other process equipment. This adjusted base cost was then updated to 1980 price levels using Marshall and Stevens Equipment Cost Indices (Chemical Engineering 1981). Tank insulation costs from a previous study (Laity et al. 1979) were updated to 1980 price levels. Dike costs were assumed to be 2% of the total media cost (Martin Marietta 1978).

Comparing the relative magnitudes of the component costs, the cost of the ethylene glycol dominates the costs of the other components. The cost of the water is insignificant.

Oil/Rock Thermal Storage Costs

Included in the oil storage subsystem cost accounts are the costs of carbon steel tanks, tank insulation, earthen containment dikes and the oil and rock heat transfer medium. Costs were estimated for systems which would deliver heat at 350°F and 500°F.

Media costs were assumed to be \$1.57/gallon based on the cost of Caloria HT-43 quoted by an Exxon sales representative. This price is what a large-volume buyer would likely be charged. The cost of the rock was assumed to be \$10/ton. Tank, insulation, and containment dike costs were estimated using the same assumptions used for the water/ethylene glycol system.

Again, the cost of the storage medium dominates other system component costs. The temperature difference across the thermocline is greater for the 350°F system than for the 500°F system. The result is that the volume requirements at the lower temperature are slightly smaller than at the higher temperature, leading to somewhat lower storage costs at the lower temperature.

Molten Salt Thermal Storage Costs

Molten salt storage costs include the cost of stainless steel tanks, internal insulation, earthen containment dikes, and the draw salt.

The cost of the draw salt was estimated with the assumption that the bulk materials would be purchased and then melted and mixed on site. This assumption was made for two reasons: 1) it is likely to be less expensive to manufacture the salt on site than to purchase it from a vendor, and 2) the cost of the heat transfer salt required at the higher storage capacities exceeds the annual unit cost of onsite draw salt production. The cost of the raw materials were obtained from the Chemical Marketing Reporter (Sept. 1980). Transportation and processing cost estimates, obtained from Martin Marietta (1978), were updated to 1980 price levels. The resulting unit cost for onsite salt production (\$0.25/lb) was less than the cost of vendor supplied salt (\$0.335/lb).

The cost of the internal tank insulation was based on the Martin Marietta design for liquid sodium storage (Martin Marietta 1978). The insulation is an alumina brick. Costs of other components, tanks and containment dikes, were estimated as discussed previously for the other storage designs.

The cost of the draw salt dominates the other costs. The unit cost of tankage is greater for the molten salt system than for the oil or water systems because stainless steel tanks are required at this temperature; however, the total tankage cost is lower, which is due to both a greater temperature difference across the thermocline and a greater heat capacity for the salt.

Air/Rock Thermal Storage

The costs of air/rock thermal storage include the cost of prestressed concrete containment vessels and the cost of a fine clay pebble storage medium. A cost of \$415/ton was assumed for the denstone storage medium (Acres American 1981). The cost of the prestressed concrete pressure vessels was obtained from EPRI (1978) and was updated to 1980 price levels.

The cost of denstone exceeds the cost of the containment; however, the concrete tank costs are also significant.

4.2.4 Interface Subsystem Costs

The interface subsystem cost account includes the cost of heat exchangers (or evaporators) and associated equipment, pumps, valves, pipe and pipe insulation. Although all these components are considered conventional hardware, many of the components will require special fabrication because of off-standard

size or material requirements. Specially fabricated items tend to be more costly than those purchased off the shelf.

Interface subsystem costs were estimated by aggregating the installed capital costs of each of the components of the system. Component costs were obtained from vendors, cost estimating guides, and technical reports. The capital costs of each interface system design were estimated at 50, 150, 300, and 600 MWt.

Heat exchanger and evaporator cost estimates were obtained from Harris Thermal Transfer Products, Inc. (Adamski 1981) Their cost estimates were based on the following assumptions:

- Units are designed and fabricated to TEMA and ASME standards by a manufacturer already in the custom, large-scale shell and tube heat exchanger business.
- The price is based on 1980 dollars with a nominal profit level.
- Shipment costs are not included.

A materials and labor cost adjustment factor was used to account for installation labor and for the cost of miscellaneous materials needed to interface the heat exchangers or evaporators with other plant equipment (Guthrie 1974).

The unit cost of pumps, valves, pipes, and pipe insulation were obtained from vendors and were multiplied by the quantity required to determine the total capital cost. As with the heat exchangers, a material and labor factor was used to account for installation labor and miscellaneous materials. Costs of the interface subsystems generating steam include the cost of a disengagement drum to separate the blowdown liquid from the process steam.

For all interface system designs, the cost of the heat transfer equipment (heat exchangers or evaporators) dominates the costs of the other components. Among the factors that influence the cost of heat exchangers are the maximum working fluid temperature and the inlet and outlet temperatures of both the working fluid and the process fluid. For example, stainless steel is required for the molten salt system, whereas the lower-temperature systems can use

carbon steel. The cost of the heat exchangers is proportional to the heat transfer area, which, in turn, is a function of the available temperature differential between the working and process fluids. The cost of the heat exchangers decreases as this temperature difference increases.

A summary of the interface subsystems costs is presented in Table 4.5. In general, interface subsystem costs increase with power level because more heat must be transferred, which requires a greater heat transfer surface area. The difference in cost between the water and the oil systems is due primarily to the oil's lower heat transfer coefficient. The salt-to-air heat exchanger is the most costly due both to a low heat transfer coefficient for the salt and to the requirement of stainless steel components at this higher temperature.

4.2.5 Balance-of-Plant Costs

Balance-of-plant costs represent those major capital expenditures necessary to complete process heat plant construction but which are not part of the collector, transport, storage, or interface subsystems. Balance-of-plant cost components are structures, land (including site preparation), instrumentation and control, spare parts, and service facilities. The characteristics of each of these components are very similar among the different concepts. Balance-of-plant cost differences between concepts result from differing quantity requirements rather than employment of different technologies.

TABLE 4.5. Interface Subsystem Costs (1980 \$)

Product Temperature (°F)	Interface Subsystem Costs (1980 \$)			
	50 MWt	150 MWt	300 MWt	600 MWt
150	215,000	528,000	997,000	1,940,000
350	1,170,000	3,680,000	7,440,000	15,000,000
500	1,520,000	4,680,000	9,410,000	18,900,000
1000	1,670,000	5,100,000	10,200,000	20,500,000
1500	-	-	-	-

Although balance-of-plant costs can be a substantial fraction of the levelized energy cost of a process heat plant, their similarity among the plant concepts tends to make them a relatively poor cost differentiator between the concepts.

Several factors affect balance-of-plant costs for solar thermal process heat plants, and differentiate process heat balance-of-plant costs from those for solar thermal electric facilities: 1) Process heat plants will be owned and operated by the user in contiguous facilities. 2) Process heat plants will require land in close proximity to the process heat user; thus land purchase cost should be based on typical industrial acreage costs. And 3) requirements for auxiliary power sources (for electric heat tracing, etc.) will be met by the user's facilities. Balance-of-plant component costs for solar thermal process heat plants are discussed in further detail in the following paragraphs. The costs are summarized in Table 4.6.

Structures costs were calculated based on the estimated floor area requirements for each building at each power level and the unit cost per square foot. The assumption of contiguous process heat plants and process heat user facilities limits the additional floor area required of a process heat plant compared to a stand-alone plant. Unit costs were developed for administration, control, maintenance, and storage buildings.

Land (including site preparation) is the most costly balance-of-plant component. In addition to the purchase cost of the land itself, the land cost includes the cost of surveying, grading, road graveling, and soil stabilizer application. Land costs were assumed to be \$20,000/acre. This unit cost is based on a survey of industrial acreage (Cohen et al. 1980) and represents a major capital expenditure for a process heat plant. The site preparation sub-components represent a small cost compared to the land but are important when compared to other components of the balance-of-plant account.

Instrumentation and control (I&C) costs are broken into master control, concentrator-related, and nonconcentrator-related subcomponents. Analysis of previous master control estimates showed little dependence of cost on variables such as power plant rating, collector field size, or variance among concepts. Thus, the master control system is represented by a fixed cost for all concepts

Table 4.6. Balance of Plant Component Costs

Structures

<u>Plant Power Rating (Mwt)</u>	<u>Total Cost (1980 \$)</u>
50	564,000
150	847,000
300	1,095,000
600	1,414,000

Land and Site Improvements

Purchase	-	\$20,000/acre
Development	-	3,210/acre

Instrumentation and Control

Master Control	-	\$1,300,000 (\$870,000 for LCNT)
Nonconcentrator related control	-	3% of receiver, storage, transport, and interface capital cost
Concentrator related control	-	varies with concept, see below

<u>Concept</u>	<u>Percentage of Concentrator Capital Costs</u>
PFCR	1.00
PFDR	0.34
FMDf	0.33
LFDR	0.10
LFDR-TC	0.20
LFDR-TR	0.20
LCNT	0.05

Spare Parts

<u>Plant Power Rating (Mwt)</u>	<u>Percentage of Distributed Capital Costs</u>	<u>Percentage of Centralized Capital Costs</u>
50	0.160	0.220
150	0.090	0.160
300	0.060	0.130
600	0.040	0.105

Service Facilities

<u>Plant Power Rating (Mwt)</u>	<u>Percentage of Collector Capital Costs</u>	<u>Percentage of Noncollector Capital Costs</u>
50	0.186	1.266
150	0.144	1.184
300	0.116	1.126
600	0.092	1.082

but the LNCT, which was estimated to have a lower master control cost because of its nontracking collectors and a general decreased need for monitoring. Much of the concentrator-related control system is already included in the concentrator cost. Concentrator-related I&C costs account for the equipment that interfaces with the master control system and the concentrator field controllers. Costs are calculated as a varying percentage of concentrator capital costs, based on the tracking requirements and the concentrator area controllable by a single command for each concept. Nonconcentrator I&C costs are calculated as 3% of receiver, storage, transport, and interface capital costs for all concepts.

The cost of power plant spare parts is estimated as a percentage of concentrator, receiver, storage, transport, interface, structures, and instrumentation and control costs. Subsystems are categorized as either distributed or centralized, depending on the concept. Distributed subsystems are those that consist of many identical, interchangeable components, such as concentrators or distributed receivers. Centralized components are more one-of-a-kind items such as PFCR receivers or the interface subsystem. Concentrators are always considered distributed. Storage, interface, structures, and instrumentation and control are always considered centralized. Receiver and transport are considered centralized for the PFCR concept and distributed for all other concepts. Spare requirements are assumed to be less (as a percentage of direct capital cost) for distributed subsystems for two reasons: 1) distributed subsystems contain multiple identical units where parts are interchangeable, and 2) the breakdown of one unit in a distributed subsystem is not as likely to be critical to plant operation as a breakdown to a centralized component would be.

Service facilities include water treatment, air and water distribution, electric distribution, communications, fire protection, and lift trucks and transportation. The assumption of contiguous process heat plant and process heat user facilities limits the additional service facilities required of a process heat plant compared to a stand-alone plant. Service facilities are calculated as percentages of collector (concentrator and receiver) and noncollector (storage, transport, interface, and structures) capital costs.

Communications, fire protection, and lift truck transportation are required for the entire plant. The other three facilities (water treatment, air and water distribution, and electric power distribution) are required only in the non-collector systems. (Electric power distribution for collectors has already been accounted for in the collector cost account).

4.2.6 Indirect and Contingency Costs

Indirect costs include the cost of engineering and supervision, construction expenses not directly attributable to any one plant component, and the contractor's fee. A contingency factor is included to compensate for unpredictable events, such as bad weather, labor strikes, price changes, design changes, or other unforeseen expenses.

Indirect and contingency costs were estimated for the overall plant, rather than disaggregating them in the cost accounts of each subsystem. Indirect costs were estimated as 16 percent of overall direct capital cost, with a contingency factor of 8 percent of capital cost. Estimating percentages were the same for all concepts at all power levels and temperatures, and were developed from a review of construction cost estimating guides, previous solar studies, and studies of other advanced energy concepts.

4.3 OPERATION AND MAINTENANCE COSTS

Operation and maintenance (O&M) costs include the costs of direct production, scheduled and unscheduled maintenance, plant overhead, and purchased power. The approach used to estimate O&M costs involved a systematic analysis of each plant subsystem to determine likely operating and maintenance requirements. Where information was available, manpower estimates were made for specific tasks, and costs were derived from these estimates. In the other cases, costs were estimated as a percentage of the installed capital cost of the system. Estimates were then aggregated to obtain the total annual O&M expenditure for each plant. This total was multiplied by a factor to account for plant overhead expenses. Details of cost estimating assumptions and techniques for direct production, purchased power, maintenance, and plant overhead are discussed in subsections 4.3.1 through 4.3.4.

In general, the two-axis tracking concepts (PFCR, PFDR, FMDF) have the lowest annual O&M costs. This is primarily because fewer concentrator/receiver units are needed at a given plant thermal power rating than are needed with one-axis tracking or nontracking systems. The FMDF concept experiences the lowest O&M costs at 150⁰F and 350⁰F at all power levels because the number of concentrator/receiver units is significantly less than the number required by the PFCR and the PFDR. At 500⁰F and 1000⁰F the costs of the transport system maintenance and the cost of replacing the heat transfer and storage fluid begin to play a dominant role for the two-axis tracking systems. At these temperatures the PFCR has the lowest O&M costs at all power levels. The lower transport maintenance and storage media replacement costs of the PFCR, as compared to the FMDF, more than make up for its higher concentrator/receiver maintenance costs at these higher temperatures.

All concepts have their highest O&M costs at 500⁰F. Both the heat capacity of the heat transfer and storage fluid and the degradation rate of the fluid account for higher costs at this temperature. The lower heat capacity of Caloria HT-43, compared to water or draw salt, requires larger volumes of fluid to transfer or store the same amount of heat. The larger volumes lead to more transport and storage subsystem equipment and, in turn, to higher maintenance costs. The difference in O&M costs between systems operating at 350⁰F and at 500⁰F can be attributed largely to the higher oil degradation rate at the higher temperature.

The one-axis tracking and the nontracking concepts incur the highest O&M costs of all the concepts. This is a result of extensive collector and transport subsystems as well as greater heat transfer media replacement requirements due to larger fluid volumes. Of these systems, the LCNT is the most expensive to operate and maintain. The LCNT requires more collectors, transport piping, and heat transfer media at a given plant thermal power rating than the other concepts.

Some studies estimate overall plant O&M costs as a percentage of the initial capital investment. This type of estimate does not account for differences in maintenance requirements among subsystems and provides little

information on the major contributors to the annual O&M costs. To provide a basis for comparison, O&M costs estimated by the systems approach were also expressed in terms of the initial capital investment. Annual O&M costs range from 0.5 to 1.5 percent of the initial capital cost.

4.3.1 Direct Production Costs

Direct production costs account for the cost of plant operators. To estimate direct production costs, a scenario was developed to provide information on how a solar plant is likely to operate and how operation requirements may differ among concepts and power levels. Based on this scenario, the number of operators required was estimated for each concept at each power level. The annual production cost was then determined by multiplying the estimated number of operators by the annual wage per operator.

The plant operating scenario assumes that the operators must be present whenever any of the plant subsystems are in use. An estimate was made of the number of operators needed to provide continuous monitoring during daily plant operations, allowing for vacations, holidays, or operating anomalies that may require additional manpower. The average length of daily operation was assumed to be the sum of the hours of collector field operation (average day length) and the hours of storage operation (nominal storage capacity in hours).

4.3.2 Purchased Energy Costs

Purchased energy costs included the costs of all auxiliary energy needed to run the plant. Among these energy requirements are energy to run pumps, motors, collector tracking devices, and heat tracing for the transport subsystem. The unit cost of purchased energy was assumed to be \$0.043/kWh.

4.3.3 Maintenance Costs

Maintenance costs include the cost of a maintenance crew and the cost of materials used to perform maintenance tasks. Both scheduled and unscheduled maintenance tasks are assumed to be performed by an on-plant maintenance crew; however, it is assumed that the plants are designed to minimize unscheduled maintenance.

The costs of scheduled and unscheduled maintenance were estimated for:
1) the collector subsystem, 2) the receiver subsystem, 3) the storage

subsystem, 4) the transport subsystem, 5) the interface subsystem, and 6) plant instrumentation. Maintenance costs are estimated either as a percentage of installed equipment costs or as an aggregate of the estimated costs of performing maintenance tasks specific to a subsystem. To estimate costs by the latter method, major maintenance tasks were identified. Then the size of the crew needed for each task was estimated based on assumptions of the rate and frequency at which the task would be performed. Multiplying this estimate by the annual wage rate gives the annual cost of the task. These task costs were aggregated to obtain the annual plant maintenance cost.

The major scheduled maintenance tasks identified for the collector subsystem include cleaning, lubricating, and manual adjusting or realigning of collectors. Cleaning is assumed to occur monthly (Martin Marietta 1978). Lubrication is assumed to be performed quarterly, and manual adjusting or realigning is assumed to occur monthly for the LCNT and quarterly for all other concepts. No specialized training is likely to be required to perform routine collector maintenance tasks.

The principal maintenance requirements for the receiver subsystem include inspection and repair of heat exchanger tubes, insulation, structures, and aperture shields. Maintenance would likely be performed by specialized personnel such as pipefitters or steamfitters. Maintenance costs for receiver subsystems are calculated as a percentage of the capital cost. Information from Boeing (1978) was used to derive the estimating percentages.

Routine maintenance for storage subsystems includes both equipment maintenance and storage fluid replacement. The cost of manpower needed to maintain the storage equipment and to replace the storage fluid was estimated as a percentage of the initial storage capital cost, based on information from the Electric Power Research Institute (1976).

The storage medium decomposes at elevated temperatures. The annual cost of replacing the storage medium is calculated from annual weight loss percentage, the initial storage volume, and the unit cost of the storage medium. For oil/rock systems the decomposition rate is assumed to be 1 wt% per week at the

higher storage temperature and about 0.008 wt% per week at the lower temperature (Aerospace Corp. 1978). Draw salt was assumed to degrade at a rate of 2.5% per year (Martin Marietta 1978). About 1% of the ethylene glycol was assumed to be replaced each year.

Expected costs for fluid replacement are made somewhat uncertain by the lack of actual decomposition data for large-scale, operating thermal storage systems. Subsystem design techniques such as venting and fluid reprocessing show promise for reducing fluid decomposition rates, but, at this time, fluid reprocessing may itself contribute to loss of heat transfer oil (Beshore 1979). Other factors affecting the overall uncertainty are the potential market value of waste products from the heat transfer oil degradation and considerable operating costs that the reprocessing may add to the thermal storage subsystem. Analysis of these factors was beyond the scope of this study.

Maintenance requirements for the transport subsystem include the equipment maintenance costs and the cost of replacing the degraded heat transfer fluid. Equipment maintenance tasks were identified as inspection of valves, replacing or repacking valves, and pump maintenance. Valve testing and pump maintenance were assumed to occur quarterly. Information on valve failure rates was used to estimate the cost of replacing or repacking valves. Maintenance tasks for the transport subsystem will require specialized personnel, such as pipefitters or steamfitters.

The principal maintenance tasks for the interface subsystem will be inspection and repair of heat exchanger tubes; testing, replacing, or repacking valves; and pump maintenance. The maintenance cost for this subsystem was estimated as a percentage of the initial capital cost. These tasks would likely be performed by either pipefitters or steamfitters.

The cost of maintaining instruments was estimated as a percentage of the installed capital cost of the plant instrumentation. This maintenance would likely be performed by personnel with specialized training, such as instrument technicians or electricians.

Unscheduled maintenance costs are estimated as a percentage of installed equipment costs, with the estimating percentages developed using information from cost estimating guides and from other solar studies.

The cost of maintenance materials is also estimated as a percentage of the installed equipment cost. Again, estimating percentages were estimated based on information from cost guides and from other solar studies.

4.3.4 Overhead Costs

Payroll overheads for operations and maintenance staff were estimated as a percentage of direct production and maintenance costs. Estimating percentages were based on information from other industries.

4.4 SUMMARY OF KEY COSTS ESTIMATES

The ranges of component costs used in assessing the levelized energy cost of each concept are summarized in Table 4.7. The ranges of component costs were taken from cost estimates generated in the SOLSTEP-IPH computer runs and from the point cost estimates used in developing code inputs. Cost ranges are reported for the specific field sizes and solar fractions used in the analysis of each concept and therefore do not necessarily reflect absolute maximums and minimums of cost.

The costs in Table 4.7 are reported as unit costs for capital cost items and as annual expenses for purchased energy cost and operations and maintenance costs, which are recurring costs. Capital costs as reported do not include escalation and interest during construction, which are addressed in the methodology to determine levelized energy costs. Recurring costs are reported as first-year costs, and as such do not include the effects of escalation over the plants lifetime, which is likewise addressed in the levelized cost methodology.

Table 4.7. Summary of Key Cost Estimates

Component	PFCR				
	150°F	350°F	500°F	1000°F	1500°F
Concentrator (\$/m ²) ^(a)	94	94	94	94	94
Receiver (\$/m ²) ^(a)	15-46	15-46	15-46	17-50	31-59
Transport (\$/m ²) ^(a)	2	3-4	3-5	3-4	20-21
Storage (\$/kWh) ^(b)	5.8-6.7	5.0-6.6	5.3-6.7	3.1-5.0	7.6
Interface (\$/kW)	3-4	23-25	30-31	33-34	0
Other Plant (\$/kW)	38-175	40-179	41-183	42-180	22-206
Indirect/Contingency (\$/kW)	43-217	51-228	53-237	57-237	27-335
Purchased Energy Cost (1000 \$/year) ^(c)	1-2470	21-2780	2-6220	8-1480	34-41300
O&M Cost (1000 \$/year) ^(c)	113-3890	122-3650	130-8850	133-4440	143-4945

Component	LFCR			
	150°F	350°F	500°F	1000°F
Concentrator (\$/m ²) ^(a)	71	71	71	71
Receiver (\$/m ²) ^(a)	59	59	59	67
Transport (\$/m ²) ^(a)	4-6	6-11	7-12	7-15
Storage (\$/kWh) ^(b)	5.8-6.7	5.0-6.7	5.3-6.7	3.1-5.0
Interface (\$/kW)	3-4	23-25	30-31	33-34
Other Plant (\$/kW)	27-159	30-141	30-146	31-157
Indirect/Contingency (\$/kW)	57-329	66-339	68-303	73-337
Purchased Energy Cost (1000 \$/year) ^(c)	11-4590	22-10800	7-10800	1-3040
O&M Cost (1000 \$/year) ^(c)	150-7000	159-7050	171-13700	168-7322

(a) m² of concentrator aperture area

(b) kWh of storage capacity

(c) costs for first year of operation

Table 4.7. (continued)

PFDR				FMDf			
150°F	350°F	500°F	1000°F	150°F	350°F	500°F	1000°F
123	123	123	123	82	82	82	82
15	15	15	29	24	24	24	29
52	56-61	62-67	86-97	8-9	10-15	11-16	13-21
5.8-6.7	5.0-6.7	5.3-6.7	3.1-5.0	5.8-6.7	5.0-6.7	5.3-6.7	3.1-5.0
3-4	23-25	30-31	33-34	3-4	23-25	30-31	33-34
33-186	34-162	36-169	41-188	25-153	28-136	29-143	29-158
54-324	64-279	70-301	88-374	46-289	56-252	60-272	64-320
2-5350	10-12100	10-16400	337-18500	3-4990	21-10900	8-14500	113-6160
99-6080	110-4600	120-10700	132-6500	87-4140	99-3210	110-9140	126-4780

LFDR-TR				LFDR-TC			LCNT	
150°F	350°F	500°F	1000°F	150°F	350°F	500°F	150°F	350°F
78	78	78	78	69	69	69	86	86
26	26	26	31	11	11	11	46	46
5-7	7-13	7-13	7-15	5-8	7-16	8-17	118	132-148
5.8-6.7	5.0-6.7	5.3-6.7	3.1-5.0	5.8-6.7	5.0-6.7	5.3-6.7	5.8-6.7	5.0-6.7
3-4	23-25	30-31	33-34	3-4	23-25	30-31	3-4	23-25
33-158	31-183	34-156	46-177	31-137	30-162	33-153	24-187	47-198
49-292	62-358	71-297	103-354	32-181	45-236	51-222	61-492	133-563
3-5080	17-17600	64-8470	56-3430	7-4430	3-14500	55-7860	5-5700	67-15400
187-23100	213-27300	237-27300	308-22800	144-15000	171-18200	199-22300	226-23600	266-22700

5.0 RESULTS

This section presents some of the principal results from the analysis of large solar thermal concepts for process heat applications. Seven generic concepts were evaluated:

1. Point Focus Central Receiver	PFCR
2. Point Focus Distributed Receiver	PFDR
3. Fixed Mirror Distributed Focus	FMDF
4. Line Focus Central Receiver	LFDR
5. Line Focus Distributed Receiver-Tracking Receiver	LFDR-TR
6. Line Focus Distributed Receiver-Tracking Collector	LFDR-TC
7. Low Concentration Nontracking	LCNT

The concepts were analyzed, when feasible, in configurations that could produce process temperatures of 150°F (65°C), 350°F (177°C), 1000°F (538°C), and 1500°F (816°C). All of the concepts were analyzed at four plant sizes; 50, 150, 300 and 600 MWt.

5.1 DESCRIPTION OF ATTRIBUTES

The evaluation of solar thermal concepts produced several results including overall system efficiency and installed capital cost and component efficiencies and costs. However, the primary final attributes characterized in the analysis are the solar fraction and levelized energy cost of each of the plant configurations. These attributes were calculated for each concept using the SOLSTEP-IPH simulation computer program (Appendix A.3).

Solar fraction (SF) is a nondimensional parameter that describes the amount of energy produced by a solar thermal plant. It is defined as

$$SF = \frac{\text{Total energy produced in a year (kWh)}}{\text{Rated capacity (kW) x number of hours in a year}}$$

Thus the solar fraction represents the ratio of the amount of energy produced by the plant to the amount of energy that the plant would have produced had it operated all the time at the rated capacity. For this study the solar fraction

does not account for scheduled or unscheduled plant outages. That is, the total energy produced assumes that the plant can operate whenever insolation is available.

For each nominal plant size (50, 150, 300, or 600 MWt) the generic concepts were analyzed in several configurations to provide results over a range of solar fractions. For a given plant size higher solar fractions can be attained by including an energy storage subsystem and increasing the size of the collector field. Plants without energy storage subsystems generally optimize with collector field sizes that produce a solar fraction in the range of 0.2 to 0.3. With energy storage and increased field sizes it is possible to attain solar fractions up to about 0.8.

Levelized energy cost (LEC) provides a useful index for comparing alternatives with different operating characteristics but the same end use. It is defined as

$$\text{LEC} = \frac{\text{Annualized cost of plant (\$)}}{\text{Total energy produced in a year (MMBtu)}}$$

The LEC represents a constant cost of energy in nominal dollars that equals the present value of all costs over the lifetime of the system. That is, if the system were to produce exactly at its expected output, and if the output were sold at a price equal to the LEC, the resultant revenues would exactly recover the full costs of the system over its lifetime, including a return on investment.

To calculate the LEC, the fixed and variable costs of a solar plant concept are estimated over the expected lifetime of the system. Fixed costs refer to the initial capital investment; variable costs are those that recur annually or intermittently, such as O&M and replacement costs. These costs are aggregated to obtain the present value in 1980 dollars. The present value is annualized over the operating life of the plant to produce a stream of equivalent annual payments. The LEC, in \$/MMBtu, is simply this annualized cost divided by the expected yearly output of the specific system.

Figure 5.1 illustrates the relationship between levelized energy cost and the distribution of increasing annual charges. The horizontal line represents the levelized busbar energy cost in \$/MMBtu. The curved line represents a hypothetical series of increasing charges. The LEC is representative of these increasing costs if the two streams of payments have the same present value.

The levelizing procedure used in this study is based on the discounted cash flow methodology proposed by Doane et al. (1976). The costs determined by this methodology are expressed in before-tax dollars.

5.2 LEVELIZED ENERGY COST AND SOLAR FRACTION

Figure 5.2 presents levelized energy cost results for the 300-MWt PFCR concepts at five temperatures. Results are presented over a range of solar

FIGURE 5.1. Relationship of Levelized Energy Costs to Increasing Annual Costs

FIGURE 5.2. Levelized Energy Costs for 300-MWt PFCR Concepts

fractions. Each curve, referred to as a design envelope, is generated by analyzing plant configurations with a fixed size (in this case 300 MWt) but various combinations of field size and storage capacity. Plants yielding higher solar fractions (those toward the right end of the curves) employed larger collector field and storage subsystems. The analysis procedure used to derive these curves is explained in more detail in Appendix A.3.

Three points are indicated on the design envelopes in Figure 5.2: the energy costs at the optimal no-storage solar fraction, a solar fraction of 0.4, and a solar fraction of 0.7. Curves similar to these were generated for each of the concepts at each process temperature and power level. Energy cost results for the solar fractions (optimal no-storage, 0.4, and 0.7) are presented for each of the concepts in Appendix B.

In Figure 5.2 the curves for the 150⁰F, 350⁰F, 500⁰F, and 1000⁰F plants are relatively flat over the range of solar fraction. The 1500⁰F design

envelope rises sharply with increasing solar fraction because of the high cost of high-temperature air storage. The flat behavior of the lower temperature curves is typical, however, of the results for all other concepts at all sizes and temperatures. The levelized energy cost at a solar fraction of 0.4 is generally within 1 to 2 \$/MMBtu of the cost over the range of solar fraction from the optimal no-storage point to 0.7. Therefore in the remainder of this section results will be presented at a solar fraction of 0.4. These results are representative of the energy costs over the range of solar fractions for any of the concepts (except the 1500°F PFCR case, as previously noted). More complete results are contained in Appendix B.

5.3 LEVELIZED ENERGY COST AND PROCESS TEMPERATURE

Figures 5.3, 5.4, 5.5 and 5.6 show energy cost results for each of the concepts at each process temperature and plant size analyzed. The trends are very similar in each of the figures, so they will be discussed together.

The LFDR-TC concept yielded the lowest levelized energy costs for process temperatures of 150°F and for some plant sizes at 350°F. The PFCR concept yielded the lowest levelized energy costs for process temperatures of 350, 500, and 1000°F. The LCNT concept yielded extremely high energy costs at all plant sizes at both of the process temperatures for which it was analyzed. Although not shown on the figures the energy cost for the LCNT concept at 350°F was either 43 \$/MMBtu (at 50 and 150 Mwt) or 44 \$/MMBtu (at 300 and 600 Mwt).

Levelized energy costs for all concepts increased as process temperatures increased. The change in costs between 500 and 1000°F is especially interesting. The molten salt transport subsystems used at 1000°F require stainless steel pipe while the oil transport subsystems used at 500°F use carbon steel. The concepts with larger transport subsystems showed proportionately larger costs. The PFCR has a minimal transport subsystem and was affected little. The two distributed systems, PFDR and LFDR-TR, have extensive transport subsystems and were severely affected. The effects on the FMDF and LFCR, concepts with modest transport subsystems, were between the two extremes.

FIGURE 5.3. Levelized Energy Costs at 50 MWt

FIGURE 5.4. Levelized Energy Costs at 150 MWt

FIGURE 5.5. Levelized Energy Costs at 300 MWt

FIGURE 5.6. Levelized Energy Costs at 600 MWt

5.4 LEVELIZED ENERGY COST AND PLANT SIZE

Figure 5.7 shows levelized energy cost results for six of the concepts at a process temperature of 500°F. Results at other process temperatures are very similar. Energy costs varied very little over the range of plant sizes from 150 to 600 MWt. It should be noted, however, that this trend cannot be expected to continue past 600 MWt. In fact, the costs for plants with a solar fraction of 0.7 (and therefore larger collector fields) already start to increase at 600 MWt.

The distributed systems (PFDR, LFDR-TC, and LFDR-TR) scale down quite well to 50 MWt. This is expected because of their modularity. The PFCR concept is beginning to show an increase in levelized energy cost going from 300 to 600 MWt. This is caused by the extremely rapid increase in tower costs for the larger plants.

5.5 CAPITAL COST

The initial capital investment for each plant was overwhelmingly the largest portion of the plant's total lifetime cost, usually representing 85 to

FIGURE 5.7. Levelized Energy Costs at 500°F

95% of the total cost. Figure 5.8 shows a breakdown of capital costs for six of the solar thermal concepts. The costs are for 300-MWt plants producing 500°F process steam with a solar fraction of 0.4. The LCNT concept is not included on this figure because it was not analyzed at 500°F. However, for comparison purposes the capital cost of the 300-MWt LCNT concept with a 0.4 solar fraction at 350°F was \$1400/kW. This is approximately twice as high as the capital costs for the other six concepts.

Figure 5.8 points out several interesting aspects of the solar thermal concepts. In all cases collector costs (concentrator and receiver) were the dominant contributor to capital cost. Transport subsystem costs were significant for the PFDR concept (and were also significant for the LCNT concept, although this is not shown). Storage and interface subsystem costs were relatively unimportant for all concepts. Balance-of-plant and indirect and contingency costs were significant but were fairly constant and did not differentiate between concepts. Finally, it is interesting to note that the capital costs for the six concepts shown are relatively even; there is far less variation in the capital costs shown in Figure 5.8 than in the levelized energy costs in Figure 5.5. This indicates that the relative efficiency of the concepts (see Figure 3.1) has a significant impact on the levelized energy costs.

FIGURE 5.8. Sample Breakdown of Capital Costs

6.0 COMMENTS, CONCLUSIONS, AND RECOMMENDATIONS

This section presents some general comments concerning the analysis and conclusions and recommendations that can be drawn from the results.

6.1 COMMENTS

In this study seven generic solar thermal concepts were evaluated based on their potential as large (50- to 600-MWt) solar thermal process heat systems. The results of this study do not necessarily reflect the relative potential of these concepts in other applications, such as small process heat systems or large or small solar thermal electric systems. Previous studies have assessed small (Laity et al. 1979) and large (Apley et al. 1980) solar thermal electric systems.

The objective of this study was to rank solar thermal concepts with the potential for commercialization in the 1990s. However, some of the concepts analyzed represent inherently nearer-term technologies than others. For example, parabolic trough collectors are currently more fully developed than central receiver or parabolic dish designs. The study did not include costs associated with bringing all concepts to a similar level of development.

The levelized energy cost values estimated in this study are based on solar insolation data from Barstow, California. This location has significantly higher levels of insolation than most other sites in the United States. One previous study (Latta et al. 1979) evaluated four of the concepts considered in this analysis (PFCR, PFDR, LFDR-TC, and LCNT) at Barstow and seven other locations around the United States. The results of that study showed that while the cost of energy from any of the systems increases significantly in areas with less insolation, the relative performance of the concepts is essentially unchanged. Therefore, we conclude that the results of this study are largely valid at other locations in a relative sense (that is, comparing one concept to another), but that actual levelized energy costs at other sites are potentially much higher than those reported in this analysis.

The economic methodology used in this analysis provides levelized energy costs expressed in before-tax dollars. The results of this study can be converted to equivalent after-tax dollars by multiplying the results by one minus the effective tax rate (in this case, $1 - 0.48$, or 0.52). For comparison, the energy costs for the least-cost systems presented in Section 5 varied from \$10/MMBtu to \$23/MMBtu over the product temperature range of 150°F to 1500°F . The equivalent range in after-tax dollars would be \$5/MMBtu to \$12/MMBtu.

The economic conditions assumed in this study have a significant impact on the absolute value of the calculated levelized energy costs. However, all of the plants considered in the study are very capital intensive, and any changes in the economic assumptions would be expected to affect all of the concepts uniformly. Therefore, although the results of this study have an uncertainty in an absolute sense, they do accurately reflect a reasonable estimate of the relative potential of the concepts in a large solar industrial process heat application.

6.2 CONCLUSIONS

The results of this study point out the following conclusions:

- The LFDR-TC concept provided the lowest levelized energy cost at low process heat temperatures (150 to 350°F).
- The PFCR concept provided the lowest levelized energy cost at high process heat temperatures (350 to 1500°F).
- The LCNT concept provided levelized energy costs that were significantly higher than any other concept at both of the temperatures at which it was analyzed (150 and 350°F).
- In general, energy costs for solar process heat systems were strongly dependent on process temperatures, but were relatively independent of solar fraction and plant size (over the range from 50 to 600 MWt).
- Collector costs are the highest capital cost item for all concepts at all temperatures and power levels, and are the major single contributor to the levelized energy cost.

- Costs for thermal energy transport subsystems show a wide variation among concepts, and can become a major component of the capital investment cost. In general, thermal energy transport costs are cheapest for centralized concepts and most expensive for distributed concepts with collectors arranged in a parallel flow path.
- The costs of the thermal energy transport subsystems were particularly significant for the distributed systems at a process temperature of 1000⁰F. This was due to the stainless steel pipe required for the transport subsystems at this temperature.
- The impact of the transport subsystems on operating cost for distributed concepts is significant, particularly the cost of power to operate heat tracing and pumps.
- The storage and interface subsystems are not major cost components for any concept.
- Because of the high cost of ethylene glycol, the selection of a 50% water/50% ethylene glycol mixture for the 150⁰F systems may not have been the optimal choice.
- The problems associated with operating large molten salt transport subsystems (such as filling, draining, and long term shut down) were not considered in detail in this study, but they are expected to be major considerations in an actual system.

6.3 RECOMMENDATIONS

Based on the results and conclusions of this study, we offer the following recommendations:

- The LFDR-TC concept should receive highest priority for commercial development for low-temperature (150 to 350⁰F) solar process heat applications.

- The PFCR concept should receive highest priority for commercial development for medium- and high-temperature (350 to 1500⁰F) solar process heat applications.
- The LCNT concept should not be developed for large (50 to 600 MWt) solar process heat applications.

7.0 REFERENCES

- Acres American, Inc. March 1981. Conceptual Design and Engineering Studies of Adiabatic CAES with Thermal Energy Storage. Final Report, Columbia, Maryland.
- Adamski, D. F. February 1981. Heat Exchanger Tradeoff Analysis Solar Thermal Power Systems. Prepared for Battelle, Pacific Northwest Laboratories by Harris Thermal Transfer Products, Inc., Talatin, Oregon.
- Aerospace Corporation. 1978. Interim Report on Small Power Systems Study. ATR-77 (7693-05)-1, Energy Systems Group, Energy and Transportation Division, Los Angeles, California.
- Apley, W. J. 1979. "SHADE - A Computer Model for Evaluating the Optical Performance of Two-Axis Tracking Parabolic Concentrators." 79-WA/SOL-13, American Society of Mechanical Engineers, New York, New York.
- Apley, W. J., et al. 1980. Assessment of Generic Solar Thermal Systems for Large Power Applications, Vol. I: Analysis of Electric Power Generating Costs for Systems Larger than 10 MWe. PNL-3533 Vol. I, Pacific Northwest Laboratory, Richland, Washington.
- Barnhart, J. S. 1980. ETRANS: An Energy Transport System Optimization Code for Distributed Networks of Solar Collectors. PNL-3327, Pacific Northwest Laboratory, Richland, Washington.
- Baumeister, T., E. A. Avallone, and T. Baumeister III. 1978. Marks' Standard Handbook for Mechanical Engineers. 8th ed., Chapter 8, pp. 149-155. McGraw-Hill, New York, New York.
- Beshore, D. G., et al. 1979. Storage Fluid Maintenance Study Using Caloria HT-43 Hydrocarbon Oil. DOE/ET/20422-1, Martin Marietta Aerospace, Denver, Colorado.
- Bird, S. P. 1980. Assessment of Solar Options for Small Power Systems Applications, Vol. V: SOLSTEP-A Computer Model for Solar Plant System Simulations. PNL-4000 Vol. V, Pacific Northwest Laboratory, Richland, Washington.
- Black & Veatch. 1977. 150 kWe Solar-Powered Deep-Well Irrigation Facility, Phase I: Preliminary Design Report. Black & Veatch, Kansas City, Missouri.
- Blake, F., et al. 1977. Central Receiver Solar Thermal Power System, Phase 1 Preliminary Design Report. SAN/1110-77, Martin Marietta Aerospace, Denver, Colorado.
- Caputo, R. S. 1975. An Initial Study of Solar Power Plants Using a Distributed Network of Point Focusing Collectors. EM342-308, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.

- Caputo, R. S. 1977. An Initial Comparative Assessment of Orbital and Terrestrial Central Power Systems. 900-780, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Carto, P. 1977. Systems Descriptions and Engineering Costs for Solar-Related Technologies, Volume V: Solar Thermal Electric Systems. MTR-7485, The MITRE Corporation, METREK Division, McLean, Virginia.
- Clausing, A. M. 1976. Potential of a Solar Collector with a Stationary Reflector and a Tracking Absorber for Electrical Power Production. SAND76-8039, Sandia Laboratories, Albuquerque, New Mexico.
- Cole, R., W. W. Schertz, and W. P. Teagan. 1977a. "Conceptual Design of a 5x CPC for Solar Total Energy Systems." In Proceedings of Concentrating Solar Collector Conference. CONF-770953-5, National Technical Information Service, Springfield, Virginia.
- Cole, R., et al. 1977b. "Performance and Testing of a Stationary Concentrating Collector." In Proceedings of Concentrating Solar Collector Conference. CONF-770953-5. National Technical Information Service, Springfield, Virginia.
- Collares-Pereira, M., J. J. O'Gallagher, A. Rabl, and R. Winston. 1978. "A Compound Parabolic Concentrator for a High Temperature Solar Collector Requiring Only Twelve Tilt Adjustments per Year." Paper presented at the International Solar Energy Congress Meeting, New Delhi, India.
- Davidson, W. S., et al. 1978. Closed Brayton Cycle Advanced Central Receiver Solar-Electric Power System. SAN-1726-(Vol. I), Boeing Engineering and Construction Company, Seattle, Washington.
- Davidson, W. S., et al. 1978. Closed Brayton Cycle Advanced Central Receiver Solar-Electric Power System, Vol. II: Evaluation, Selection, Conceptual Design and Assessment of a Closed Brayton Cycle Advanced Central Receiver Solar-Electric Power Plant with Coupled Sensible Heat Storage. SAN-1726-1 (Vol. II), Boeing Engineering and Construction Company, Seattle, Washington.
- DiCanio, D. G., W. J. Treytl, F. A. Jur, and C. D. Watson. 1979. Line Focus Solar Thermal Central Receiver Research Study. DOE/ET/10426-1, FMC Corporation, Santa Clara, California.
- Doane, J. W., et al. 1976. The Cost of Energy from Utility-Owned Solar Electric Systems. JPL-5040-29, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Electric Power Research Institute. November 1979. Conceptual Design of Thermal Energy Storage Systems for Near-Term Electric Utility Applications. Prepared for the Electric Power Research Institute by General Electric Company, Schenectady, New York.

- El Gabalawi, N, et al. 1978. A Modularized Computer Program for Solar Thermal Power Plants. 5102-80, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Fujita, T., et al. 1977. Projection of Distributed-Collector Solar-Thermal Electric Power Plant Economics to Years 1990-2000. DOE/JPL-1060-77/1, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Guthrie, K. M. 1974. Process Plant Estimating, Evaluation, and Control. Graftsman Book Company of America, Solana Beach, California.
- Hallet, R. W., and R. L. Gervais. 1977. Central Receiver Solar Thermal Power System, Phase I: CDRL Item 2, Pilot Plant Preliminary Design Report, Volume 2 - System Description and System Analysis. SAN/1108-8, McDonnell Douglas Astronautics Company, Huntington Beach, California.
- Kast, M., P. Ortiz, and H. Whitehouse. "Solar Production of Industrial Process Steam for Stauffer Chemical Company." In Proceedings of Solar Industrial Process Heat Conference, pp. 327-334. SERI/TP333-429, Solar Energy Research Institute, Golden, Colorado.
- Laity, W. W., et al. 1979. Assessment of Solar Options for Small Power System Applications, Volume I: Executive Summary. PNL-4000 Vol. I, Pacific Northwest Laboratory, Richland, Washington.
- Laity, W. W., et al. 1979. Assessment of Solar Options for Small Power System Applications, Volume II: Analysis of Concepts. PNL-4000 Vol. III, Pacific Northwest Laboratory, Richland, Washington.
- Laity, W. W., et al. 1979. Assessment of Solar Options for Small Power System Applications, Volume III: Identification and Characterization of Concepts for Analysis. PNL-4000 Vol. II, Pacific Northwest Laboratory, Richland, Washington.
- Latta, A. F., et al. 1979. The Effects of Regional Insolation Differences Upon Advanced Solar Thermal Electric Power Plant Performance and Energy Cost. DOE/JPL-1060-17, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Leary, P. L., and J. D. Hankins. 1979. A User's Guide to MIRVAL--A Computer Code for Comparing Designs of Heliostat-Receiver Optics for Central Receiver Solar Power Plants. SAND77-8280, Sandia Laboratories, Albuquerque, New Mexico.
- McGraw-Hill, Inc. 1981. Chemical Engineering. New York, New York.
- Powell, J. C., et al. 1974. Dynamic Conversion of Solar Generated Heat to Electricity. NASA CR-134724, Honeywell, Inc., Minneapolis, Minnesota, and Black & Veatch, Kansas City, Missouri.

Powell, J. C., et al. 1977. Solar Pilot Plant, Phase I: Preliminary Design Report, Vol. 2, System Description and System Analysis. SAN/1109-8, Honeywell, Inc., Minneapolis, Minnesota.

Russell, J. L., et al. 1976. Preliminary Systems Analysis of a Solar Power Central Station. GA-A13974, General Atomic Company, San Diego, California.

Schnell Publishing Company, Inc. January 1980. Chemical Marketing Reporter New York, New York.

Schuster, J. R., et al. 1979. Line Focus Solar Central Power Systems, Phase I Midterm Topical Report for the Period September 30, 1978 through March 31, 1979. GA-A15408, General Atomic Company, San Diego, California.

Tracey, T. R., et al. 1978. Conceptual Design of Advanced Central Receiver Power System. Final Report, Martin Marietta Corporation, Denver, Colorado.

Williams, O. M. 1978. "Thermochemical Energy Transport Costs for a Distributed Solar Power Plant." Solar Energy. 20:333-342.

Workhoven, R. M., and V. E. Dudley. 1978. Performance Testing of the General Atomic Fixed Mirror Solar Concentrator. SAND78-0624, Sandia Laboratories, Albuquerque, New Mexico.

APPENDIX A

ANALYSIS CODES

APPENDIX A

ANALYSIS CODES

This appendix briefly describes the three major computer codes used in the analysis of solar thermal process heat systems. The SHADE program was used to characterize the optical performance of the concentrator subsystems and calculate geometric optical data. The ETRANS program was used to optimize and cost the thermal energy transport subsystems required for each generic concept. After characterizing each of the concepts, a performance simulation and cost analysis was conducted with the SIPH computer code.

A.1 SHADE

As previously reported, a computer model, SHADE (Selection of Heliostat Arrangement for Distributed Engines), was developed at the Pacific Northwest Laboratory to aid in determining the optical performance of two-axis tracking parabolic concentrators (Apley 1979). The shading of individual mirror assemblies in a field of parabolic dishes determines the optimal field arrangement and the most efficient method of plant operation. SHADE provides a simple and inexpensive analytical tool for examining certain design aspects of solar thermal power systems using a network of point-focusing parabolic concentrators.

All but one of the major loss mechanisms depend on parameters associated with a single parabolic dish: the quality of manufacture, the materials selected, the receiver aperture size, the concentration ratio set by rim and acceptance angle, and the desired receiver operating temperature. Because shading is the one loss mechanism that does depend on how a network of parabolic dishes is arranged, a code like SHADE can be used to establish the optimal field layout.

SHADE uses a relatively simple set of calculational techniques to transform the parabolic dish center coordinates into a solar axis system, such that the field of mirrors is oriented as it would appear to an observer located along a line to the sun. It is then possible to check if mirrors located

between the target dish and the sun overlap preset points on the target dish. The number of preset points chosen on the target dish determines the accuracy of the overall shading value and the resolution of the individual mirror's shading profile.

The sun's position can be described in terms of two angles. The azimuth is the angle east or west of the south direction; the altitude is the angle between the sun and the horizon. Therefore transforming the axes can be conducted in two steps. The first step is to turn the mirrors to face the sun in the azimuthal direction. With the mirrors oriented in the correct azimuthal plane, it only remains to tilt them back to the proper altitude angle.

While the calculational techniques described in the preceding section are very short and simple, their necessary frequent repetitions require certain features to reduce the total number of calculations. For example, if a 500-mirror field were being evaluated at 15-minute intervals for an entire year, and the necessary mirror profile resolution required 100 preset points on each mirror, over 5×10^{13} separate calculations would have to be conducted. Several features have been incorporated into SHADE to reduce this number:

1. Before calculating the individual shading point-by-point, those mirrors that could possibly shade the target mirror are determined.
2. If it is determined that a point on an individual mirror has been shaded, no further calculations are conducted for that point.
3. The number of days used to determine field performance has a significant effect on the number of calculations required, but calculating for greater than a certain number of days results in no appreciable gain in the accuracy of the final results. Therefore, if only general field layout patterns are desired, the number of required calculations can be significantly reduced by not evaluating system performance for all 365 days of the year.

The three features incorporated in SHADE are listed in order of their impact on reducing the number of calculations. The first two do not affect the accuracy of the determinations; however, using the third feature does introduce a small error. The magnitude of this error is small enough to allow initial

field layout siting. By performing a series of analyses using solar data for relatively few days during the year, important information can be gained to determine the general mirror placement. When this information is incorporated into a more advanced field layout plan, an analysis can then be conducted for the entire year to provide more precise performance information.

SHADE makes it possible to determine the individual shading profiles as a function of time. Information on which mirror shades another is also available, and flags can be set to cause one mirror to be shut down, enabling another mirror to operate at a greater power level. However, the information SHADE can best supply to the plant operator or control circuit is a prioritized list of the parabolic dishes that should be operated. This list will:

- allow low performers to be shut down for scheduled maintenance
- provide the most effective overall operation if, for some reason, the plant is required to operate at partial load
- establish when the individual dishes are capable of generating greater than standby power and therefore should be started or secured
- delineate the optimal operating condition when one mirror is out of comparison
- provide the operator with continually updated information detailing the extent of power available from the field under a variety of scenarios.

SHADE is a valuable tool for predicting the optimal field layouts and operating modes for solar thermal power systems employing distributed parabolic concentrators. The code provides information from which the system performance and cost interaction can be determined to achieve the optimal overall plant configuration. Regardless of the planned use for a parabolic concentrator network, a code like SHADE will be required to ensure that the most efficient and economically viable system is placed and maintained in operation.

A.2 ETRANS

The Energy Transport System optimization code was developed for this project because of the diversity and complexity of the many transport networks involved. ETRANS uses frequently cited layouts for dish and trough collector fields (Figure 3.3 and 3.4, Section 3.3). In addition, the user may specify field layouts via input for other collector types, e.g., central receivers. Optimization is done on a section-by-section basis; the optimal section design is that combination of pipe diameter and insulation thickness that yields the minimum annualized system-resultant cost. Among the quantities included in the costing algorithm are 1) labor and materials costs associated with initial plant construction, 2) operating expenses due to daytime and nighttime heat loss, and 3) operating expenses due to pumping power requirements.

This section contains brief descriptions of the system performance calculations and the solution procedure employed in ETRANS. The field layouts and piping system specifications are discussed in Section 3.3. ETRANS is described in a great deal more detail by Barnhart (1980).

A.2.1 System Performance Calculations

The performance of the energy transport system is characterized by the pump power required and the heat losses incurred. The pump power and daytime heat loss are calculated on a section-by-section basis via a steady-state analysis using average values for fluid flow, ambient temperature, and collector performance. The nighttime heat loss model also uses an average ambient temperature and assumes that the working fluid lies stagnant in the pipe network. Local fluid properties (section inlet values) are used in all cases except for collector risers, downcomers, and connecting pieces for which nominal fluid properties are used.

Pump Work

The energy required to pump the working fluid through a section for a period of t hours per day is calculated as

$$PW = \left[f \left(\frac{L}{D} \right)_{eq} \rho \frac{V^2}{2} \right] \left[\frac{\dot{m}}{\rho_s} \frac{t}{n_p n_m} \right] \quad (A.1)$$

Important assumptions utilized in Equation (A.1) include

- fully turbulent flow through smooth pipes
- resistance to flow of valves and fittings expressed in terms of $(L/D)_{eq}$ with values based on Crane (1974)
- the aforementioned assumption of steady flow at average conditions.

This equation is used with each candidate pipe size for a given section to determine the corresponding pumping costs.

Implicit in this section-by-section optimization routine is the assumption that the optimal diameter for a section may be specified without regard to its location in the field. However, because each field consists of several parallel flow paths, all of which are constrained to undergo the same net pressure drop, this assumption is incorrect. Those sections located in shorter loops can often be made smaller than the apparent optimum with no resulting increase in pump work due to the need to throttle most of the flows. During the first pass through the field, however, the amount of "extra" pressure drop available in each loop is unknown, and each section is sized according to the method described above. To take advantage of the need to equalize loop pressure drops, ETRANS makes a second (optional) pass through the field, downsizing sections where possible to reduce capital costs. A bonus is the simultaneous reduction in heat loss due to the smaller pipe sizes.

Heat Loss

For both day and night heat loss calculations, the pipe is assumed to be at fluid temperature and the outside of the insulation at ambient temperature. The daytime heat loss calculation thus reduces to the straightforward analysis of a fluid flowing at steady state through a single-walled cylinder.

For night heat loss calculations, the fluid is assumed to be stagnant. Depending upon the fluid's initial state and the rate of heat loss, the fluid

may remain in its initial state or drop to a lower one (e.g., from superheated to subcooled). The analysis is complicated by other factors as well: 1) the temperature of a two-phase mixture remains constant as it loses heat, while that of subcooled and superheated fluids does not; 2) the thermal capacitance of the pipe must be accounted for; and 3) the thermal conductivity of the insulation may change greatly with temperature.

For heat-traced systems the analysis is more complicated still. When the calculations show that the fluid will freeze before the night ends, heat trace power is turned on at the level required to maintain the fluid at the freezing point. The cost of the heat trace energy is then added to the other operating expenses and thus becomes another element in the life-cycle cost. In this way ETRANS determines directly whether it is more cost-effective to run the heat tracing or to install thicker insulation.

A.2.2 Solution Procedure

The major steps involved in the ETRANS solution procedure are illustrated in Figure A.1. As noted previously, the field is optimized on a section-by-section basis using local fluid properties and flow rate. The executive routine MAIN is responsible for stepping through the field, whose size and shape are specified via input. Each section is optimized via the four-step procedure shown in Figure A.1. First, MAIN supplies the upstream pressure and enthalpy to a support subroutine, PROP. The other fluid properties of interest are simply interpolated from tables supplied from input and returned to MAIN.

Second, MAIN passes this information, along with the section length, flow rate, symmetry factor, and the number and type of fittings to be included, to the program workhorse, OPTIM. Component costs and material properties are passed to OPTIM via input. OPTIM consists primarily of two nested DO loops. In the outer loop, the pipe diameter is varied and the pumping costs calculated for each size. In the inner loop, the insulation thickness is varied and the cost due to heat loss calculated for each thickness. Capital costs are summed; total operating expenses are determined; and the annualized system-resultant cost is found for every possible combination. The performance and costs of the

FIGURE A.1. ETRANS Solution Procedure Outline

optimal combination are saved and sent to subroutine ONWARD. This bookkeeping routine uses the section symmetry factor to add the results to the cumulative field totals for later output. Control is then returned to MAIN, where the cycle begins anew.

When both the supply and return sides have thus been completely traversed, subroutine SUMRY is called to print the results. The user may then elect to go through the pipe downsizing routine, referred to in the discussion on pump work, by calling subroutine THROTL. This subroutine performs much like MAIN in that it directs the same four-step sequence to optimize individual sections. The important difference is that pumping costs are irrelevant so long as the pressure drop stays below a specific limit. THROTL determines, for each section within a loop, all the pipe sizes that yield a pressure drop within the limit. Then, for the loop as a whole, it finds the combination of size reductions that leads to the greatest savings. The appropriate reductions are then made, and the corresponding changes in the field totals are logged by subroutine ONWARD. When the process is completed, SUMRY is called once again to print the revised results.

A.3 SOLSTEP-IPH

The simulation code, SOLSTEP-IPH (SOLSTEP-Industrial Process Heat), was developed at the Pacific Northwest Laboratory to facilitate the evaluation of proposed designs for solar thermal industrial process heat plants. It allows the user to analyze the thermodynamic and economic performance of a conceptual design for several field size - storage capacity configurations. This feature makes it possible to study the levelized energy cost of a proposed concept over a range of plant solar fractions.

SOLSTEP-IPH was adapted from the electric plant simulation code SOLSTEP, which was developed as part of the small power systems study (Bird 1980). SOLSTEP is based on the framework of computer programs used in earlier solar thermal studies. Specifically, these were a set of programs developed by the Aerospace Corporation in 1975 that were subsequently consolidated and modified at the California Institute of Technology's Jet Propulsion Laboratory (Caputo 1977; Fujita et al. 1977; El Gabalawi et al. 1978).

The code simulates the operation of a solar thermal plant design on a macroscopic, subsystem basis. Concentrator, receiver, energy transport, energy storage, and interface subsystems are considered in simple, yet complete models. The code accounts for collector optical performance variations with respect to the time of day and time of year. Other aspects of concentrator and receiver performance can be treated as functions of component power level, ambient air temperature, and wind speed. The transport subsystem model accounts for partial load operation and for warmup and heat trace energy requirements.

In this study the plant designs were analyzed using the 1976 Barstow, California solar insolation and meteorological data compiled by the Aerospace Corporation. The code does, however, have the capability to use a large number of insolation data formats for numerous sites throughout the United States. The simulations are conducted on a time-step basis, performing steady-state computations at a number of discrete time steps to attain an approximate estimate of the plant's transient performance over the total analysis period.

Following the thermodynamic simulation, an economic evaluation of each plant design is performed. The costing methodology calculates capital costs for the component subsystems and equipment replacements and determines annual operation and maintenance charges. An economic analysis using a discounted cash flow methodology (Doane et al. 1976) then combines the lifetime plant costs and yearly plant energy production to determine a levelized energy cost.

An important requirement of the study was to determine plant performance over a range of solar fractions. To achieve this, the code actually analyzes a matrix of collector field sizes and storage capacities for each nominal plant design. The various combinations of field and storage yield an array of plant solar fractions and levelized energy costs. Typical results for an analysis of this type are presented in Figure A.2. The series of adjacent curves represents the results for each specified field size. Points on each curve correspond to the array of storage capacities (in terms of hours of storage) considered. Each point on the graph depicts an energy production figure, specified in terms of a plant solar fraction, and a levelized energy

cost for a particular plant configuration. Note that, at smaller field sizes, only the smaller storage capacities are represented. This is because the analysis considers one field size at a time and calculates the performance at increasing storage capacities. When it is clear that the addition of further storage capacity yields no increase in plant output, and therefore is not cost-effective, the calculation for the field size is completed and the next field size is considered, again starting at the lowest storage capacity.

The significant portion of the plant in Figure A.2 is the broad curve across the bottom of the matrix. This envelope represents the locus of field and storage combinations that yields the minimum levelized energy costs over the range of solar fractions. These are the plant designs in which field size and storage capacity are matched to achieve least-cost performance. This curve has a number of uses: it shows how levelized energy cost varies with solar fraction for a concept; it may be used to select the least-cost field and storage combination at a specific solar fraction; or it may be used to select the overall least-cost plant design and the corresponding solar fraction and levelized energy cost.

FIGURE A.2. Sample Plot of Energy Cost Versus Solar Fraction

REFERENCES - APPENDIX A

- Apley, W. J. 1979. "SHADE - A Computer Model for Evaluating the Optical Performance of Two-Axis Tracking Parabolic Concentrators." 79-WA/SOL-13, American Society of Mechanical Engineers, New York, New York.
- Barnhart, J. S. 1980. ETRANS: An Energy Transport System Optimization Code for Distributed Networks of Solar Collectors. PNL-3327, Pacific Northwest Laboratory, Richland, Washington.
- Bird, S. P. 1980. Assessment of Solar Options for Small Power Systems Applications, Vol. V: SOLSTEP-A Computer Model for Solar Plant System Simulations. PNL-4000 Vol. V, Pacific Northwest Laboratory, Richland, Washington.
- Caputo, R. S. 1977. An Initial Comparative Assessment of Orbital and Terrestrial Central Power Systems. 900-780, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Crane. 1974. Flow of Fluids Through Valves, Fittings, and Pipe. Crane Company, Chicago, Illinois.
- Doane, J. W., et al. 1976. The Cost of Energy from Utility-Owned Solar Electric Systems. JPL-5040-29, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- El Gabalawi, N, et al. 1978. A Modularized Computer Program for Solar Thermal Power Plants. 5102-80, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.
- Fujita, T., et al. 1977. Projection of Distributed-Collector Solar-Thermal Electric Power Plant Economics to Years 1990-2000. DOE/JPL-1060-77/1, Jet Propulsion Laboratory, California Institute of Technology, Pasadena, California.

APPENDIX B

ENERGY COST RESULTS

APPENDIX B

ENERGY COST RESULTS

This appendix presents levelized energy costs for each of the generic concepts for each process temperature and plant size for which they were analyzed. Energy costs are expressed in 1980 \$/MMBtu. Results are presented for a plant configuration with no storage (which typically yields a solar fraction of 0.2 to 0.3) and for plant configurations with storage (which yielded solar fractions of 0.4 and 0.7). The amount of storage found to be optimal for a given solar fraction varies between concepts. However, optimized plants with a solar fraction of 0.4 generally optimized with 3 to 6 hours of energy storage. Plants with a solar fraction of 0.7 generally optimized with 12 to 15 hours of energy storage.

Levelized Energy Cost (\$/MMBtu, 1980 \$)

Concept	Temperature (°F)	Plant Size (MWt)	No Storage	0.4 Solar Fraction	0.7 Solar Fraction
PFCR	150°	50	16	16	16
		150	14	14	16
		300	13	14	15
		600	14	14	16
	350°	50	18	17	17
		150	15	16	16
		300	15	15	16
		600	15	16	16
	500°F	50	18	18	18
		150	16	17	17
		300	16	16	17
		600	16	17	18
	1000°F	50	19	19	18
		150	17	17	16
		300	17	17	17
		600	16	17	17
	1500°F	50	25	27	30
		150	24	27	31
		300	23	28	33
		600	23	30	36
PFDR	150°F	50	17	18	18
		150	16	17	18
		300	16	16	18
		600	16	16	18
	350°F	50	19	20	20
		150	19	19	20
		300	19	19	20
		600	19	19	20
	500°F	50	21	22	23
		150	21	22	23
		300	21	22	23
		600	21	22	24
	1000°F	50	28	29	28
		150	27	28	28
		300	27	28	28
		600	27	28	28

Levelized Energy Cost (\$/MMBtu, 1980 \$)

<u>Concept</u>	<u>Temperature (°F)</u>	<u>Plant Size (Mwt)</u>	<u>No Storage</u>	<u>0.4 Solar Fraction</u>	<u>0.7 Solar Fraction</u>
FMDF	150°F	50	16	16	17
		150	14	15	16
		300	14	15	16
		600	14	15	16
	350°F	50	19	19	19
		150	18	18	19
		300	18	18	19
		600	17	18	19
	500°F	50	21	21	22
		150	19	20	21
		300	19	20	22
		600	19	20	22
	1000°F	50	25	23	23
		150	23	22	23
		300	23	22	23
		600	23	23	23
LFCR	150°F	50	21	20	21
		150	19	19	19
		300	18	18	19
		600	17	18	19
	350°F	50	24	23	22
		150	21	21	21
		300	21	21	21
		600	21	20	21
	500°F	50	25	25	25
		150	23	23	24
		300	23	23	24
		600	22	23	24
	1000°F	50	28	27	26
		150	26	25	25
		300	25	25	24
		600	25	24	24

Levelized Energy Cost (\$/MMBtu, 1980 \$)

Concept	Temperature (°F)	Plant Size (MWt)	No Storage	0.4 Solar Fraction	0.7 Solar Fraction
LFDR-TR	150°F	50	17	18	19
		150	16	17	18
		300	16	17	18
		600	16	17	18
	350°F	50	21	21	23
		150	20	21	22
		300	20	22	24
		600	20	21	23
	500°F	50	24	24	26
		150	23	24	25
		300	23	24	26
		600	23	24	26
	1000°F	50	33	32	33
		150	32	32	33
		300	31	32	34
		600	32	32	34
LFDR-TC	150°F	50	12	13	14
		150	11	12	14
		300	10	12	14
		600	10	12	14
	350°F	50	15	16	18
		150	15	16	18
		300	14	16	19
		600	14	16	19
	500°F	50	19	19	23
		150	17	19	23
		300	17	19	23
		600	17	19	24
LCNT	150°F	50	31	31	32
		150	29	31	32
		300	29	30	31
		600	29	30	31
	350°F	50	41	43	45
		150	41	43	45
		300	41	44	46
		600	42	44	47

APPENDIX C

COST ESTIMATE SCALING RELATIONSHIPS

APPENDIX C

COST ESTIMATE SCALING RELATIONSHIPS

Cost estimate scaling relationships (CESRs) were developed for each capital investment and operation and maintenance cost account. The CESRs are mathematical relationships that relate subsystem costs to system physical parameters, such as concentrator field size or plant power rating. The advantage of CESRs is that they allow simulation of many plant configurations without developing detailed cost estimates for each one. These relationships facilitate detailed analyses of plant cost variations with design changes.

Developing CESRs involved determining which physical parameters can best be related to component costs, estimating costs for components at several values of the physical parameters, and then using regression analysis to determine the form and coefficients of the CESR. Cost estimate scaling relationships used in this study generally have the form

$$\text{Cost} = A + B(X)^S + C(Y)^T$$

Here X and Y are the physical parameters used to scale component costs. Fixed costs, which are costs not related to the physical scaling parameters, are represented by A. Variable cost coefficients, represented by B, C, S, and T, represent scaling factors. These scaling factors are unique to each plant concept and are subject to the constraints under which the systems were modeled. Functional forms of the CESRs for each capital investment and operation and maintenance cost account are given in Tables C.1 and C.2, respectively.

TABLE C.1. Cost Estimate Scaling Relationships for Capital Investment Costs

Subsystem	Relationship	Term Definition
Concentrator	$\text{Cost} = A(X)$	$X = \text{Concentrator field size, m}^2$
Receiver	$\text{Cost} = A+B(X)^S+C(X)^T$	$X = \text{Concentrator field size, m}^2$
Thermal Transport	$\text{Cost} = A(X)^S$	$X = \text{Number of concentrators}$
Interface	$\text{Cost} = A+B(X)$	$X = \text{Plant power rating, MW}$
Thermal Storage	$\text{Cost} = A+B(X)$	$X = \text{Storage capacity, kWh}$
Structures	$\text{Cost} = A(X)^S$	$X = \text{Plant power rating, MW}$
Land	$\text{Cost} = A(B+C(X))Y/Z$	$X = \text{Plant power rating, MW}$ $Y = \text{Concentrator field size, m}^2$ $Z = \text{Ground cover ratio}$
Instrumentation and Control	$\text{Cost} = A+B(X)+C(Y)$	$X = \text{Concentrator cost}$ $Y = \text{Cost of receiver, thermal transport, thermal storage, and interface}$
Spare Parts	$\text{Cost} = A(X)+B(Y)+C(Z)$	$X = \text{Concentrator cost}$ $Y = \text{Cost of receiver and thermal transport}$ $Z = \text{Cost of interface, thermal storage, structures, and instrumentation and control}$
Service Facilities	$\text{Cost} = A(X)+B(Y)$	$X = \text{Cost of concentrator and receiver}$ $Y = \text{Cost of thermal transport, interface, thermal storage, and structures}$

Table C.2. Cost Estimate Scaling Relationships for Operation and Maintenance Costs

SUBSYSTEM	EQUATION	PARAMETER DESCRIPTION
Direct Production	$COST=(A(X)+B(Y)+C)Z$	X=Power Level, MWt Y=Storage Capacity, hours Z=Annual Wage, \$/yr
Collector	$COST=A(X)(Y)$	X=Field Size, m ² Y=Annual Wage, \$/yr
Receiver	$COST=A(X)$	X=Receiver Cost, \$
Storage Equipment	$COST=A(X)$	X=Storage Cost, \$
Storage Medium	$COST=A(X)^B C(Y)(Z)$	A=Decomposition Rate, %/yr X=Storage Capacity, hours Y=Storage Capacity, kWh Z=Unit Cost of Medium, \$/lb
Transport Equipment	$COST=A(X)B)(Y)C)D$	X=Solar Factor Y=Number of Collectors
Transport Medium	$COST=A+B(X)^C$	X=Number of Collectors
Interface	$COST=A(X)$	X=Interface Cost, \$
Instruments	$COST=A(X)$	X=Instruments Cost, \$
Maintenance Materials	$COST=A(U+V)+B(X+Y+Z)$	U=Collector Cost, \$ V=Receiver Cost, \$ X=Storage Cost, \$ Y=Transport Cost, \$ Z=Interface Cost, \$
Unscheduled Maintenance	$COST=A(U+V)+B(X+Y+Z)$	U=Collector Cost, \$ V=Receiver Cost, \$ X=Storage Cost, \$ Y=Transport Cost, \$ Z=Interface Cost, \$

DISTRIBUTION

<u>No. of Copies</u>		<u>No. of Copies</u>	
	<u>OFFSITE</u>	27	DOE Technical Information Center
	A. A. Churm DOE Patent Division 9800 S. Cass Avenue Argonne, IL 60439		W. Beverly Boeing Engineering and Construction Co. P.O. Box 3707 Seattle, WA 98124
6	J. E. Rannels Division of Solar Thermal Energy Systems U.S. Department of Energy 600 E Street, NW Washington, DC 20585		T. Fujita Jet Propulsion Laboratory California Institute of Technology 4800 Oak Grove Drive Pasadena, CA 91103
	L. Melamed Division of Solar Thermal Energy Systems U.S. Department of Energy 600 E Street, NW Washington, DC 20585		V. Truscello Jet Propulsion Laboratory California Institute of Technology 4800 Oak Grove Drive Pasadena, CA 91103
	G. W. Braun Division of Solar Thermal Energy Systems U.S. Department of Energy 600 E Street, NW Washington, DC 20585		J. J. O'Gallagher The Enrico Fermi Institute The University of Chicago Chicago, IL 60637
	M. Gutstein Division of Solar Thermal Energy Systems U.S. Department of Energy 600 E Street, NW Washington, DC 20585		R. R. Walters E-Systems, Energy Technology Center Dallas, TX 75222
	W. Hockheiser Division of Solar Thermal Energy Systems U.S. Department of Energy 600 E Street, NW Washington, DC 20585		D. G. Curphey FMC Corporation Engineered Systems Division 328 Brokaw Road Santa Clara, CA 95052

No. of
Copies

F. C. Dahms
General Atomic Company
P.O. Box 81608
San Diego, CA 92138

V. Dugan
Sandia Laboratories
P.O. Box 5800
Albuquerque, NM 87185

J. Iannucci
Sandia Laboratories - 8326
Box 969
Livermore, CA 94550

R. C. Wayne
Sandia Laboratories - 8450
Box 969
Livermore, CA 94550

A. Frank
Solar Energy Intelligence Report
Box 1067
Blair Station
Silver Springs, MD 20910

A. Herlevich
Solar Energy Research Institute
1536 Cole Boulevard
Golden, CO 80401

D. Hooker
Solar Energy Research Institute
1536 Cole Boulevard
Golden, CO 80401

J. P. Thornton
Solar Energy Research Institute
1536 Cole Boulevard
Golden, CO 80401

J. D. Reichert
Crosbyton Solar Power Project
Texas Tech University
P.O. Box 4709
Lubbock, TX 79409

No. of
Copies

ONSITE

DOE Richland Operations Office

H. E. Ransom

71 Pacific Northwest Laboratory

W. J. Apley
J. S. Barnhart
S. P. Bird (47)
D. R. Brown
M. K. Drost (5)
J. A. Fort
B. A. Garrett-Price
W. W. Laity
S. W. Matsumoto
T. A. Williams (5)
Technical Information (5)
Publishing Coordination PY (2)