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Characterization of Solar Thermal Concepts for Electricity Generation

Volume 2 - Appendices

T. A. Williams
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March 1987

Prepared for the U.S. Department of Energy
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Pacific Northwest Laboratory
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CHARACTERIZATION OF SOLAR THERMAL CONCEPTS FOR ELECTRICITY GENERATION

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Richland, Washington 99352

PREFACE

The research and development (R&D) described in this document was conducted within the U.S. Department of Energy's (DOE) Solar Thermal Technology Program. The goal of the Solar Thermal Technology Program is to advance the engineering and scientific understanding of solar thermal technology, and to establish the technology base from which private industry can develop solar thermal power production options for introduction into the competitive energy market.

Solar thermal technology concentrates solar radiation by means of tracking mirrors or lenses onto a receiver where the solar energy is absorbed as heat and converted into electricity or incorporated into products as process heat. The two primary solar thermal technologies, central receivers and distributed receivers, employ various point and line-focus optics to concentrate sunlight. Current central receiver systems use fields of heliostats (two-axis tracking mirrors) to focus the sun's radiant energy onto a single tower-mounted receiver. Parabolic dishes up to 17 meters in diameter track the sun in two axes and use mirrors or Fresnel lenses to focus radiant energy onto a receiver. Troughs and bowls are line-focus tracking reflectors that concentrate sunlight onto receiver tubes along their focal lines. Concentrating collector modules can be used alone or in a multi-module system. The concentrated radiant energy absorbed by the solar thermal receiver is transported to the conversion process by a circulating working fluid. Receiver temperatures range from 100^{o}C in low-temperature troughs to over 1500^{o}C in dish and central receiver systems.

The Solar Thermal Technology Program is directing efforts to advance and improve each system concept through the research and development of solar thermal materials, components, and subsystems, and the testing and performance evaluation of subsystems and systems. These efforts are carried out through the technical direction of DOE and its network of national laboratories who work with private industry. Together they have established a comprehensive, goal directed program to improve performance and provide technically proven options for eventual incorporation into the Nation's energy supply.

To be successful in contributing to an adequate national energy supply at reasonable cost, solar thermal energy must eventually be economically competitive with a variety of other energy sources. Components and system-level performance targets have been developed as quantitative program goals.

The performance targets are used in planning research and development activities, measuring progress, assessing alternative technology options, and making optimal component developments. These targets will be pursued vigorously to insure a successful program.

This study is aimed at providing a relative comparison of the thermodynamic and economic performance in electric applications of several concepts that have been studied and developed in the DOE solar thermal program. Since the completion of earlier systems comparison studies in the late 1970's, there have been a number of years of progress in solar thermal technology. This progress has included development of new solar components, improvements in component and system design detail, construction of working systems, and collection of operating data on the systems. This study provides an updating of the expected performance and cost of the major components and the overall system energy cost for the concepts evaluated. The projections in this study are for the late 1990's time frame, based on the capabilities of the technologies which could be expected to be achieved with further technology development.

This is the second volume of a two-volume report. Volume 1 contains the analysis, characterization and evaluation of six concepts for solar thermal electric generation. This volume contains appendices which provide additional information on the approach used in the analysis and further detail of the study results.

SUMMARY

A number of solar thermal concepts for generating electricity have been proposed. The goal of this study was to provide a relative comparison of the thermodynamic and economic performance of several concepts which have been studied and developed in the DOE solar thermal program for power generation applications. Four central receiver systems, a parabolic dish system, and a parabolic trough system were evaluated in this study. The dish system and all of the central receiver concepts analyzed show the potential to be economically competitive electricity producing technologies.

Volume 1 of this report documented the analyses and evaluation of the concepts. This volume contains appendices which provided additional information on the approach used in the analysis, and further detail of the study results. Appendix A describes tradeoffs involved in the orientation of trough collector fields. The methodology used in the calculation of levelized energy costs is described in Appendix B. Additional detail on the annual energy output for each of the technologies is provided in Appendix C. Appendix D provides a discussion on the method and assumptions used in developing optical performance models for central receiver systems, and gives a detailed description of the results obtained. Plant cost data is shown in Appendix E, and a method for first-order sensitivity analyses using the data is described. The calculational approach used to estimate the manufacturing cost of distributed solar components is described in Appendix F.

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TROUGH EVALUATION USING AN EAST-WEST LAYOUT

APPENDIX A

TROUGH EVALUATION USING AN EAST-WEST LAYOUT

An east-west axis (north-south tracking) trough system will yield a lower annual energy output than a north-south axis (east-west tracking) trough system. Since the capital and operating cost are identical, the north-south system will have a lower levelized energy cost. Thus the north-south system was selected as the baseline trough case and is discussed in the main body of the report. The east-west trough orientation is discussed here as a sensitivity analysis.

A.1 CONCEPT DESCRIPTION

This system is identical to that described in Section 3.6, except that the collectors layout is east-west and the tracking is north-south. Briefly, the system uses a single-curvature parabolic concentrator that focuses solar insolation on a fixed linear receiver. The collector is rotated around the east-west axis to track the sun's diurnal motion. The transport system is used to move 218°C (425°F) oil from storage to the collector field where it is heated in the receivers to 310°C (590°F). The transport system then returns the heated oil to the thermocline storage. Steam for the Rankine cycle conversion system is generated in a heat exchanger/steam generator assembly that uses the hot oil as a heat source.

A.2 PERFORMANCE APPROACH

The performance analysis of the east-west axis trough system was done in the same manner as the analysis of the north-west axis trough system. The only differences between the two concepts occurs in the optical performance.

A.2.1 East-West Axis Trough System Concentrator Performance Approach

The total optical loss for a trough system is the combination of several effects:

- o concentrator reflectivity
- o receiver absorbtivity
- o receiver cover glass transmittance

- o concentrator/receiver intercept
- o receiver shadowing loss
- o incidence angle modifier
- o cosine loss
- o row-to-row shadowing

The first six of these parameters are calculated in a manner identical to those for the north-south axis trough system described in Section 4.2.1.3. The last two will be discussed below.

The cosine loss for an east-west axis trough can be readily calculated for any sun position. Whenever the sun's rays are not parallel to the aperture normal there will be a cosine loss; this in effect, reduces the size of the aperture. The effective aperture area of an east-west axis trough is equal to the product of the aperture area and the cosine of the incident angle (the angle between the aperture normal and the sun's rays). The cosine of the incident angle is calculated according to Equation A.1.[a]

$$\cos(i) = \sqrt{1 - \cos^2(alt)\sin^2(az)} \qquad (A.1)$$

where i = incident angle
alt = solar altitude angle
az = solar azimuth angle

While significant for north-south axis trough systems, row-to-row shadowing is extremely small for east-west axis trough systems with a 50 percent packing factor[b]; hence, it is ignored in this sensitivity analysis.

(a) Boes, E. C. 1981. "Fundamentals of Solar Radiation." In Solar Energy Handbook, ed. J. F. Kreider and F. Kreith. Chapter 2. McGraw-Hill, New York.

(b) Sharp, J. K., and C. J. Chiang. 1983. "Siting Tradeoffs for Parabolic Trough Fields." In Proceedings of the Distributed Solar Collector Summary Conference -- Technology and Applications, ed. R. L. Alvis, pp. 32-42. Sandia National Laboratories, Albuquerque, New Mexico.

A.2.2 East-West Axis Trough System Balance-of-System Performance Approach

The analytical approach for the other components was identical to that described in the following sections of the main body of the report:

- o receiver, Section 4.2.2.3;
- o transport, Section 4.2.3.3;
- o storage, Section 4.2.4.2;
- o conversion, Section 4.2.5.2; and
- o parasitic losses, Section 4.2.6.

A.3 ANNUAL PERFORMANCE RESULTS FOR THE EAST-WEST AXIS TROUGH SYSTEM

The annual average concentrator, receiver, and field efficiencies are listed in Table A.1 for both the east-west axis and north-south axis trough systems. The efficiency is constant with power level and capacity factor, due to the modular nature of the concept.

TABLE A.1. Trough Annual Average Field Efficiency Results

	East-West Axis	North-South Axis
Concentrator Eff.	60.2	63.9
Receiver Eff.	59.3	60.1
Field Eff.	35.7	38.4

The concentrator annual efficiency of the east-west layout is about 6 percent lower than that of the north-south layout (this difference is discussed in more detail in Section A.4). The result of the lower concentrator efficiency is a corresponding decrease in the annual energy impinging on the receiver. While the receivers of both configurations have the same thermal losses when operating, the receiver efficiency for the east-west layout is lower. This is because the absolute losses are a greater percentage of the incoming energy.

The design point performance of the transport, storage, and conversion systems are identical for both the east-west axis and north-south axis trough systems. Small differences in the annual average performance of these subsystems do occur due to the differences in the concentrator and receiver performance.

Annual average transport figures-of-merit for selected east-west axis systems are shown in Table A.2; the transport figure-of-merit is a combination of the transport thermal efficiency and the pump work as explained in Section 4.1. The values reported in Table A.2 are almost identical to those of the north-south axis systems presented in Table 6.47 in the main body of the report.

TABLE A.2. East-West Axis Trough Transport Annual Average Figures-of-Merit

Plant Size, MW_e	Figure-of-Merit No Storage	Figure-of-Merit 0.4 Capacity Factor
0.5	92.6	92.6
2.0	94.0	93.6
10.0	91.6	91.6
30.0	90.1	90.0
100.0	87.7	87.5

Tables A.3 and A.4 present the annual average storage figure-of-merit and conversion efficiencies, respectively. The storage figure-of-merit is calculated in a manner similar to the transport figure-of-merit and is explained in Section 4.1. The values presented for the east-west axis systems are almost indistinguishable from those of the north-south axis systems shown in Tables 6.49 and 6.51 in the main body of the report.

TABLE A.3. East-West Axis Trough Annual Average Storage Figure-of-Merit

Plant Size, MW_e	Figure-of-Merit 0.4 Capacity Factor
0.5	99.0
2.0	99.0
10.0	99.1
30.0	99.1
100.0	99.1

TABLE A.4. East-West Axis Trough Annual Average Energy Conversion Efficiency

Plant Size, MW_e	Conversion Efficiency No Storage	Conversion Efficiency 0.4 Capacity Factor
0.5	20.3	20.6
2.0	23.0	23.4
10.0	25.2	26.0
30.0	25.4	26.2
100.0	25.7	26.7

Figures A.1 through A.4 show waterfall efficiency charts for optimal east-west axis trough systems with no-storage and 0.4 capacity factor at 2.0 and 100.0 MW_e. These can be compared with the waterfall efficiency charts for north-south axis trough systems shown in Figures A.5 through A.8. The charts are almost identical except for the concentrator and receiver efficiencies.

A general view of the annual average system efficiency of 0.4 capacity factor plants as a function of plant size is presented in Figure A.9. The north-south axis trough efficiency is also shown for purposes of comparison. (See Figure 8.2 for a comparison of the annual average system efficiency as a

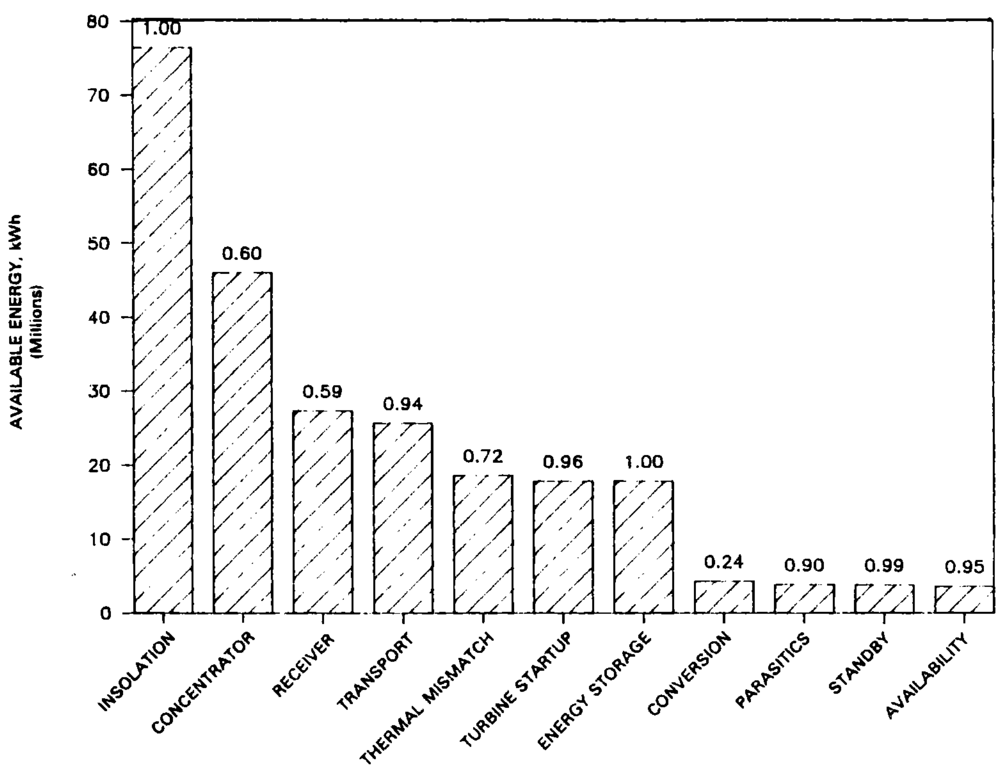

Figure A.1. Annual Energy Losses for an East-West Trough System with a No-Storage Capacity Factor in a 2 MW_e Plant (27,000 m^2 field)

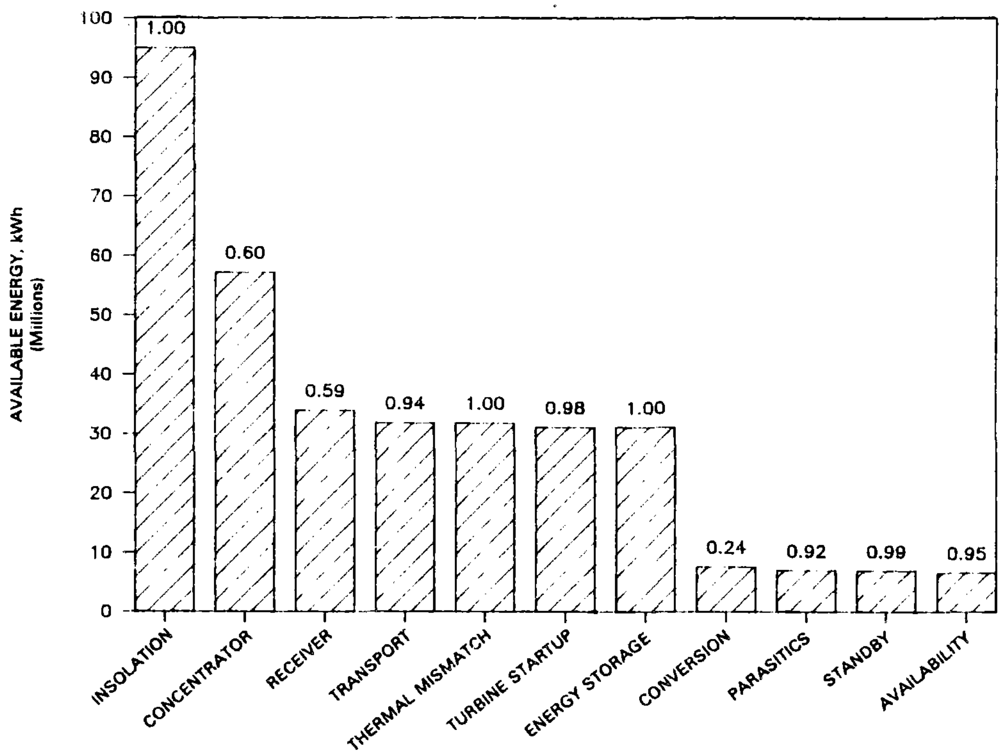

Figure A.2. Annual Energy Losses for an East-West Trough System with a 0.4 Capacity Factor in a 2 MW_e Plant (36,000 m^2 field)

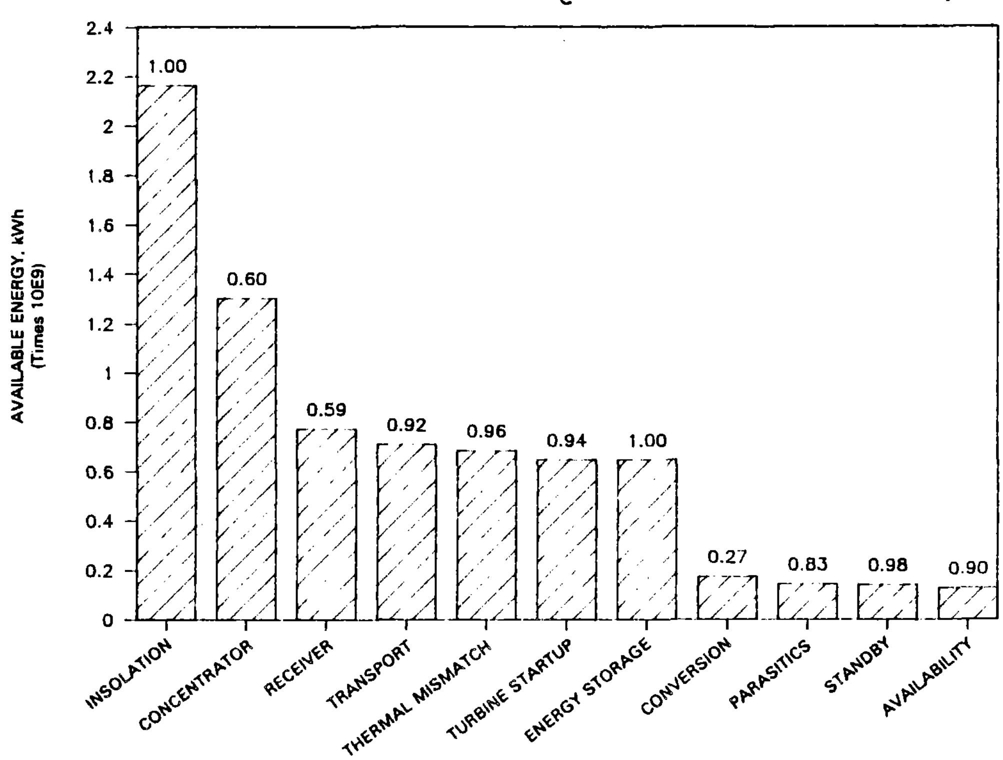

Figure A.3. Annual Energy Losses for an East-West Trough System with a No-Storage Capacity Factor in a 100 MW_e Plant (760,000 m^2 field)

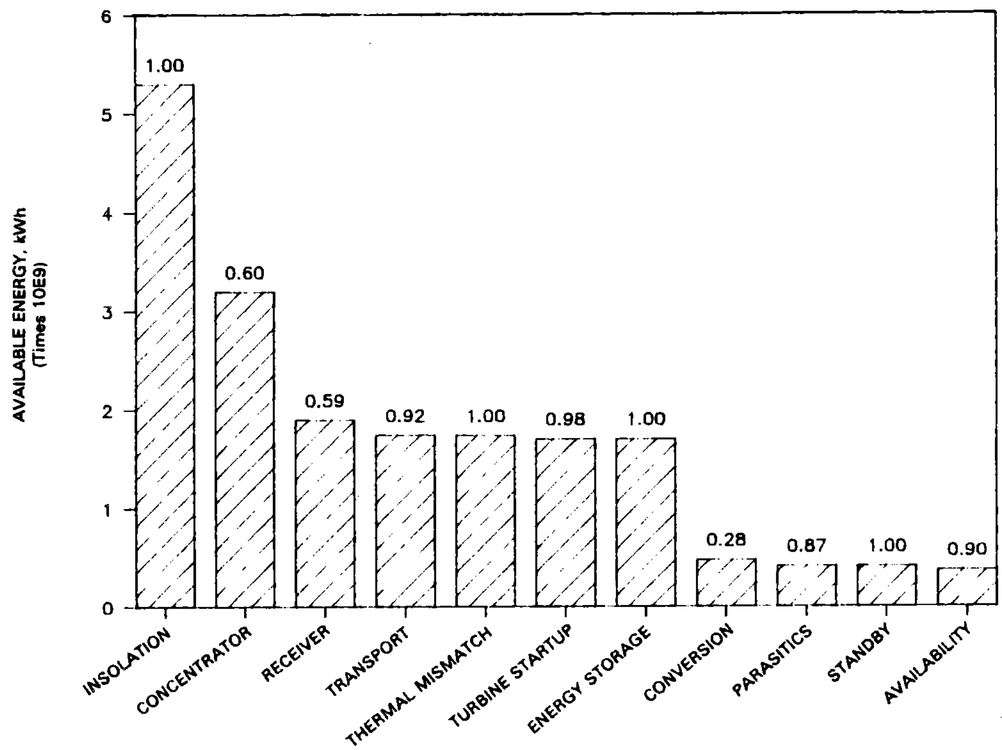

Figure A.4. Annual Energy Losses for an East-West Trough System with a 0.4 Capacity Factor in a 100 MW_e Plant (1,796,000 m^2 field)

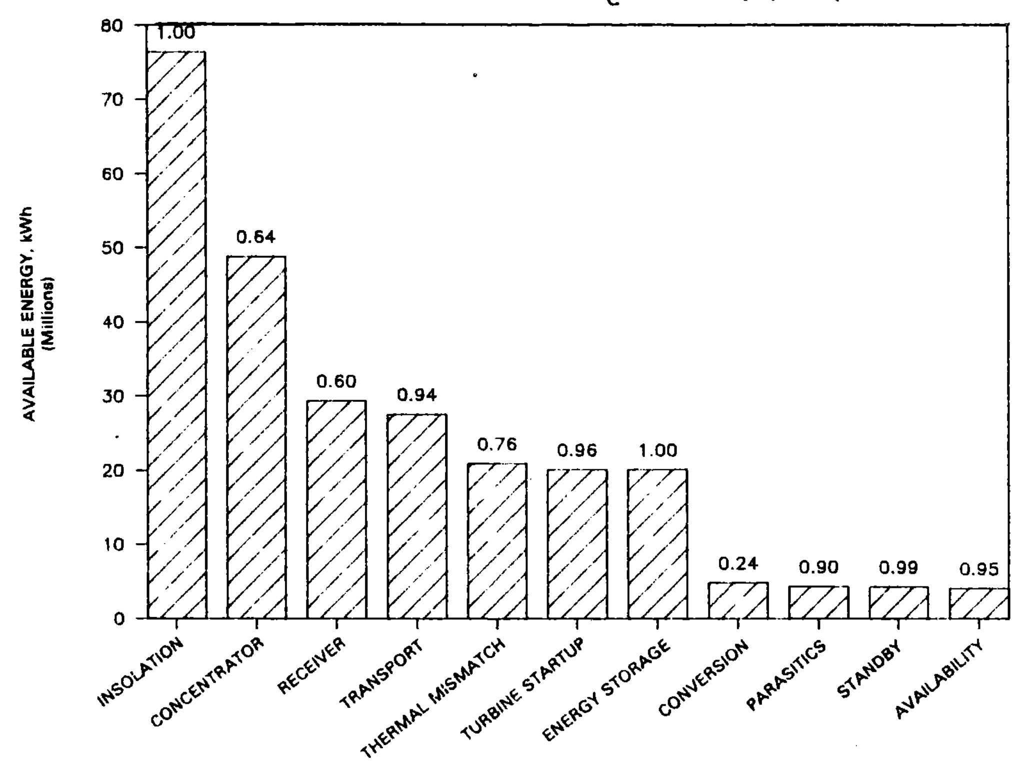

Figure A.5. Annual Energy Losses for a North-South Trough System with a No-Storage Capacity Factor in a 2 MW_e Plant (27,000 m^2 field)

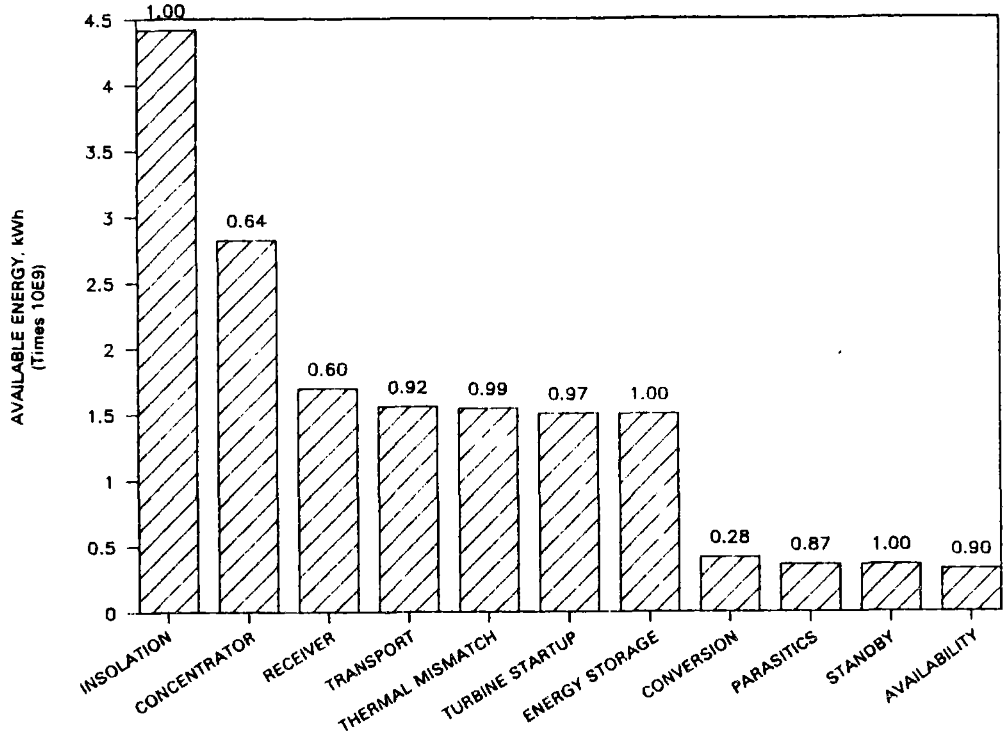

Figure A.6. Annual Energy Losses for a North-South Trough System with a 0.4 Capacity Factor in a 2 MW_e Plant (34,000 m^2 field)

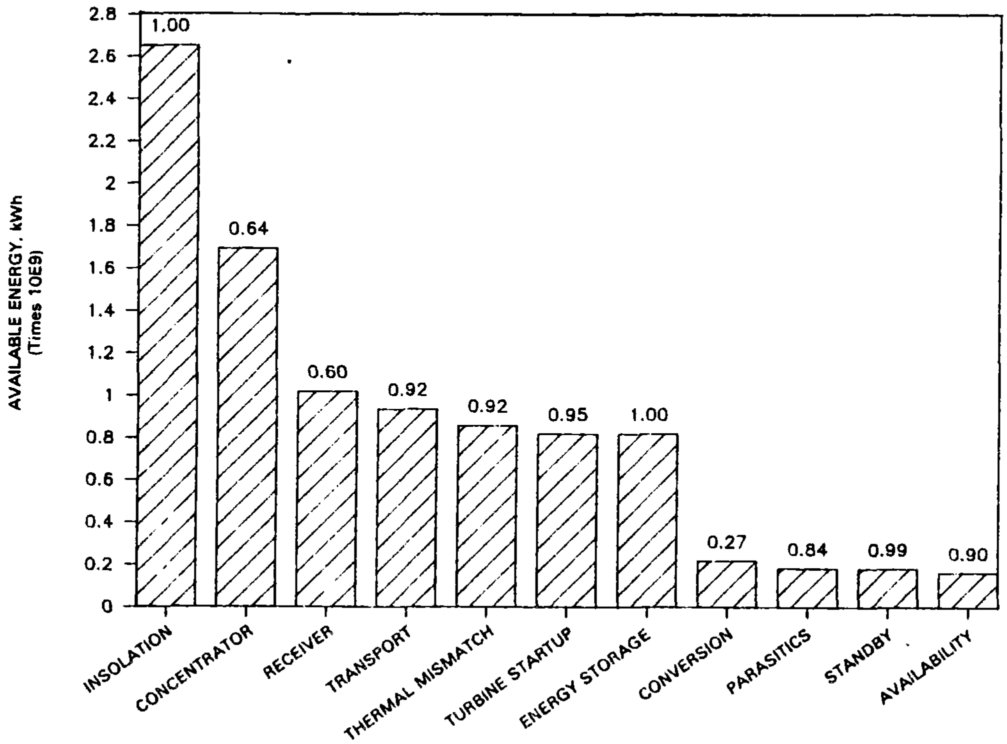

Figure A.7. Annual Energy Losses for a North-South Trough System with a No-Storage Capacity Factor in a 100 MW_e Plant (930,000 m^2 field)

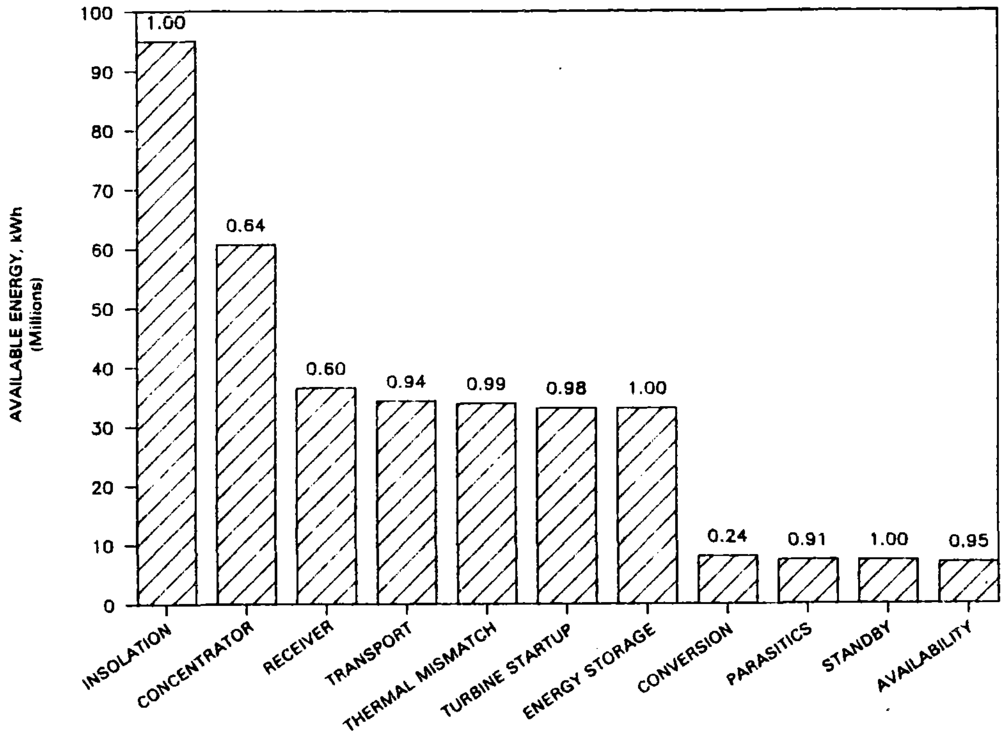

Figure A.8. Annual Energy Losses for a North-South Trough System with a 0.4 Capacity Factor in a 100 MW_e Plant (1,692,000 m^2 field)

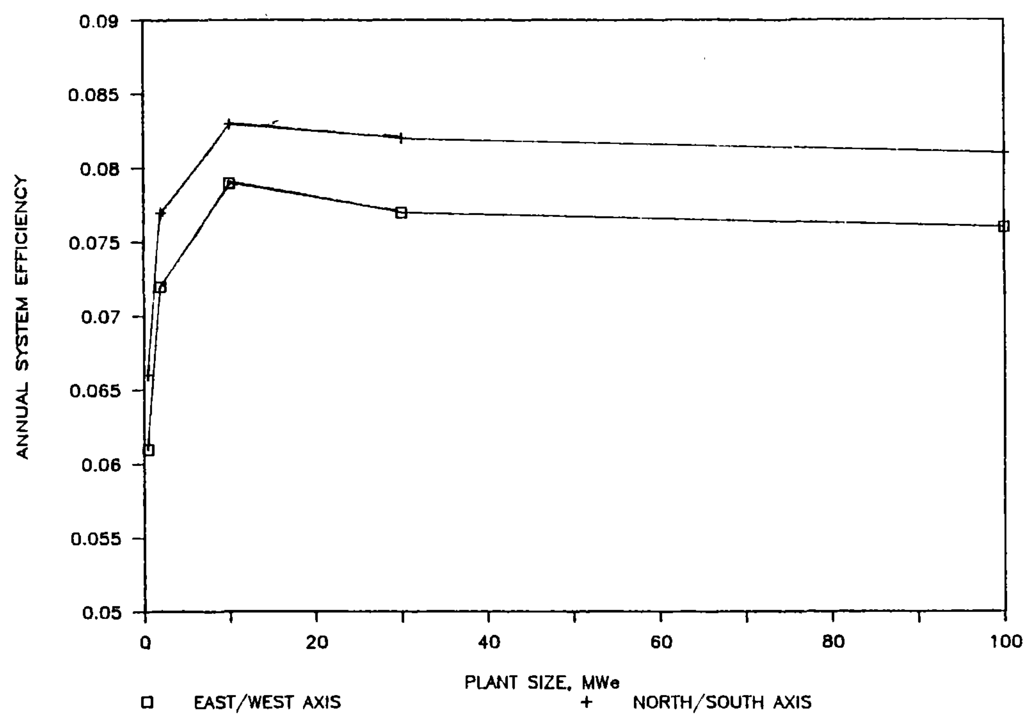

Figure A.9. Annual System Efficiency for North-South and East-West Trough Systems with a 0.4 Capacity Factor as a Function of Plant Size function of plant size for the north-south trough and the other concepts evaluated in this study.) From Figure A.9 it is clear that the north-south axis trough system has a higher annual average system efficiency at all plant sizes (due to the greater field efficiency), and that the relative difference in system efficiencies is maintained across plant size. Hence, the north-south axis trough system would have a higher annual output for any given field size.

In Figure A.10 the annual average system efficiency as a function of capacity factor is presented for both the east-west and north-south axis trough systems at the $30MW_e$ plant size. The relative difference in annual average system efficiencies is maintained over the range of capacity factors by the north-south axis system, just as it was across system size.

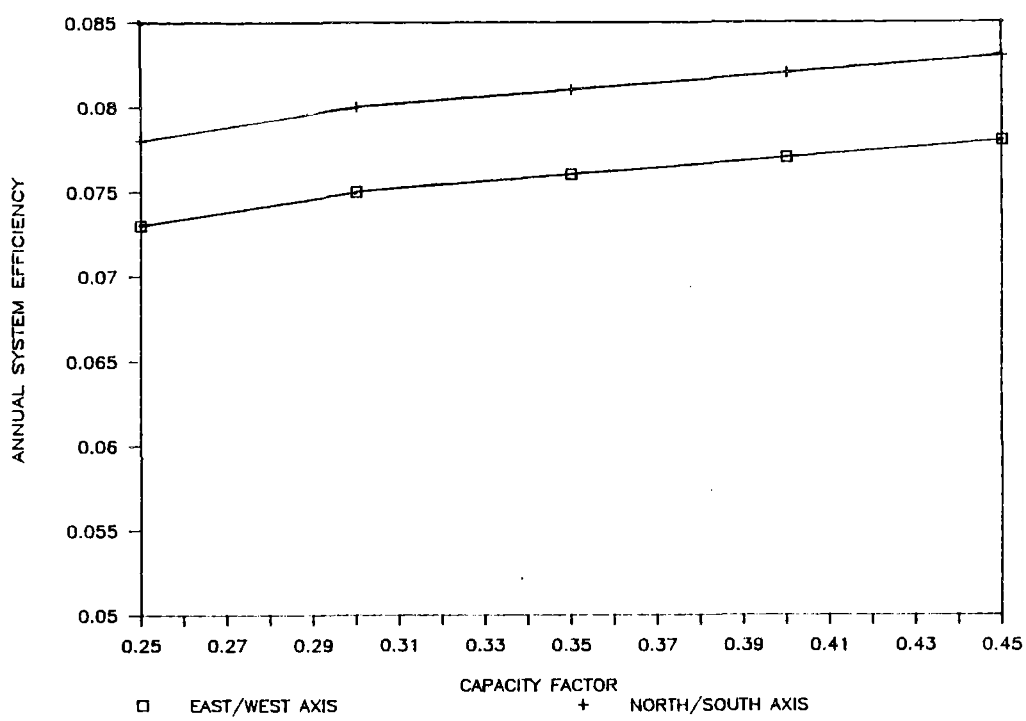

Figure A.10. Annual System Efficiency for 30 MW_e North-South and East-West Trough Systems as a Function of Capacity Factor

A.4 HOURLY PERFORMANCE COMPARISON

Although the trough field orientation results in a fairly small difference in annual average field efficiency is (2.7 percentage points, or about a 7% difference), the discrepancy between the collector efficiency of the two systems, for any particular hour of the year, can be striking. There are three effects driving the differences in hourly efficiency between the east-west and north-south orientations: the incident angle modifier, cosine loss, and the row-to-row shadowing.

The incident angle modifier accounts for the variation of optical properties with changes in the angle of incidence, such as, end loss effects and receiver support shadowing (See Section 4.2.1.3; and Cameron and Dudley 1986). Thus, when the incident angle is non-zero, there will be optical losses that exceed the cosine loss. For an east-west axis trough system, the incident angle is zero only at solar noon. The incident angle associated losses, at times off noon, will be the largest when the sun is due east or west (morning or afternoon). For a north-south axis trough system, the incident angle is zero when the sun is due east or west. The largest incident angle will occur at solar noon, and the associated optical losses will be the greatest at this time.

Cosine loss calculation and row-to-row shadowing discussion for an east-west axis trough system is presented in Section A.2.1. For a north-south axis trough system this calculation and discussion is in Section 4.2.1.3.

A.4.1 East-West Axis Trough System Hourly Collector Efficiency

Figures A.11 and A.12 show the hourly trough collector efficiency and energy collection for east-west axis trough systems, respectively. The hourly collector efficiency is almost indistinguishable with the time of year. And, the hourly energy collected is practically invariant between the different days shown. The lower hourly values of energy collected for April occur for the most part due to the lower available insolation on that day.

Hourly direct normal insolation for summer and winter solstice and the vernal equinox are shown in Figure A.13. The product of the direct normal insolation and the collector efficiency is the energy collected per square meter of collector area.

Incident angle modifier and cosine loss reduces the available energy in the mornings and evenings when the sun is low in the eastern or western sky. This results in the east-west axis trough being unable to take advantage of the longer summer days. However, in the winter, when the sun is generally in

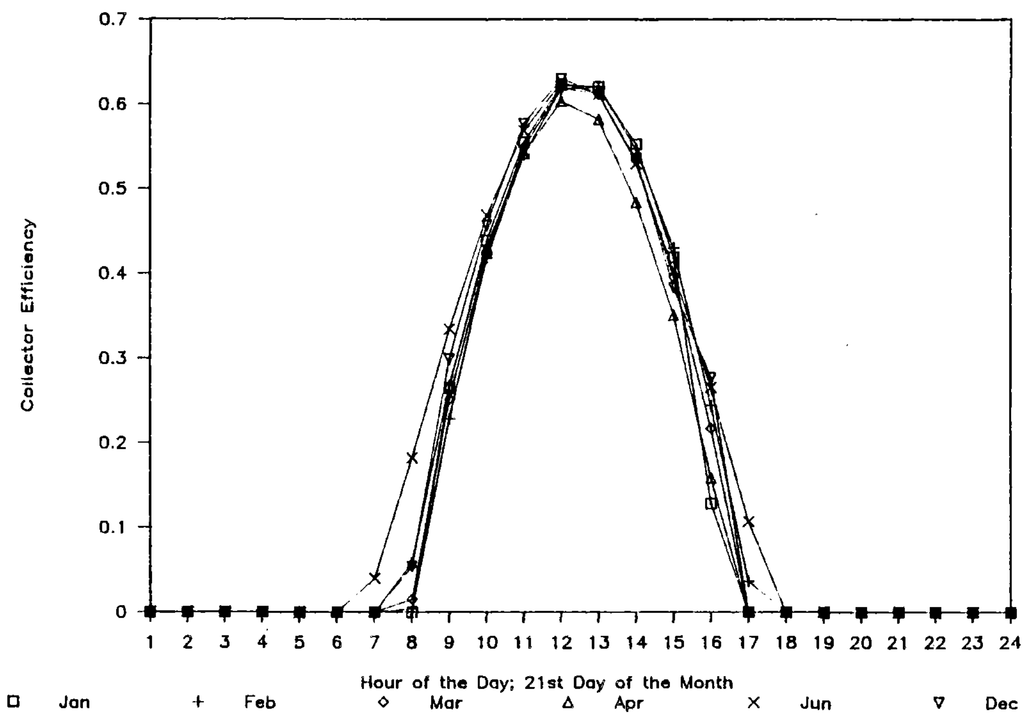

Figure A.11. Hourly Collector Efficiency for a Trough System with an East-West Layout and North-South Tracking

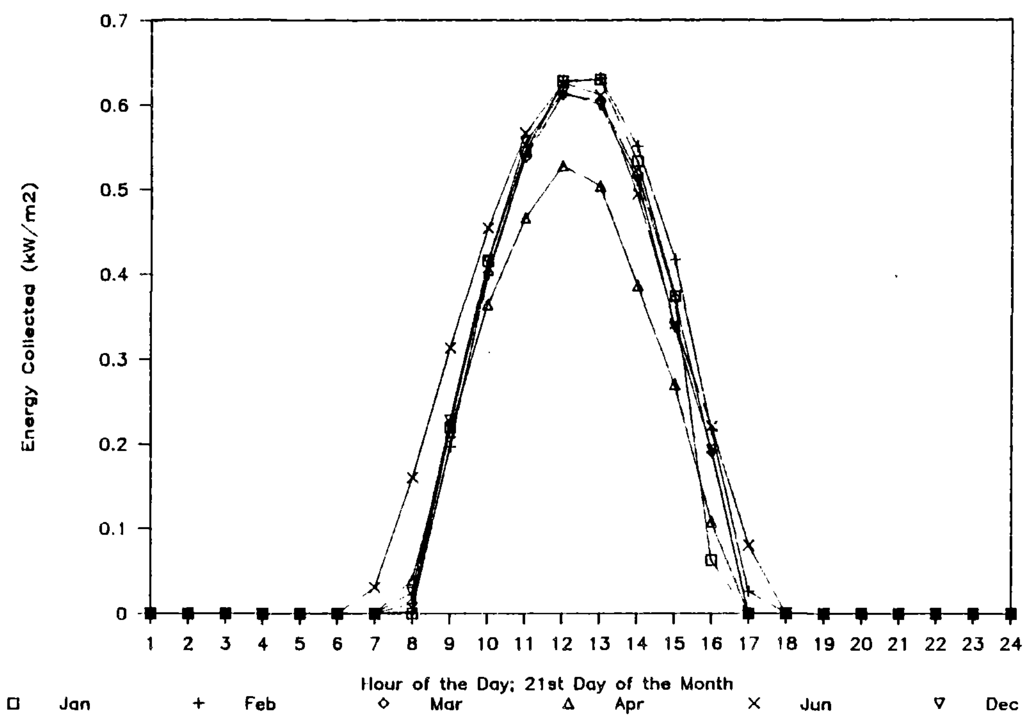

Figure A.12. Hourly Energy Collected for a Trough System with an East-West Layout and North-South Tracking

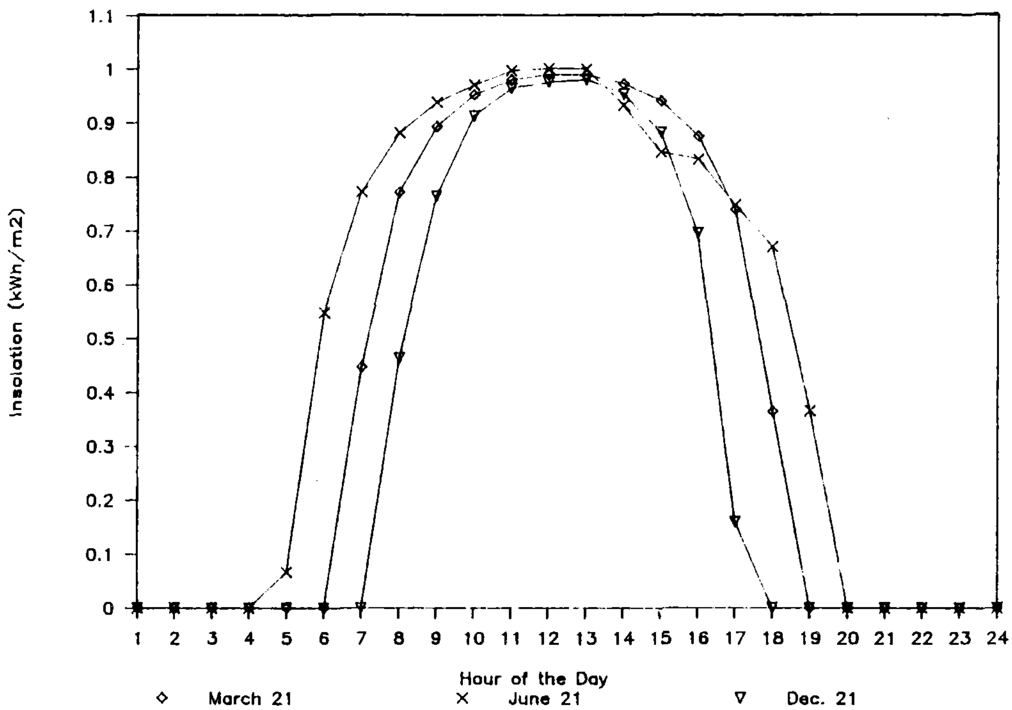

Figure A.13. Hourly Direct Normal Insolation (Barstow, 1976)

the southern sky, the east-west axis trough system is able to collect a large percentage of the available energy.

A.4.1 North-South Axis Trough System Hourly Collector Efficiency

The hourly trough collector efficiency and energy collection for north-south axis trough systems are shown in Figures A.14 and A.15, respectively. The hourly collector efficiency shows huge variations with the different months of the year shown. And, the amount of energy collected closely follows the collector efficiency.

For a north-south axis trough system, the reduction in available energy due to the incident angle modifier and the cosine loss will be the greatest at solar noon. As Figure A.14 shows, the collector efficiency is never at a peak in the middle of the day. In addition, the incident angle modifier and cosine loss severely reduce the energy output for the north-south axis system during the winter months when the sun is low in the southern sky; this effect is particularly strong at solar noon. Just as the north-south axis trough collects

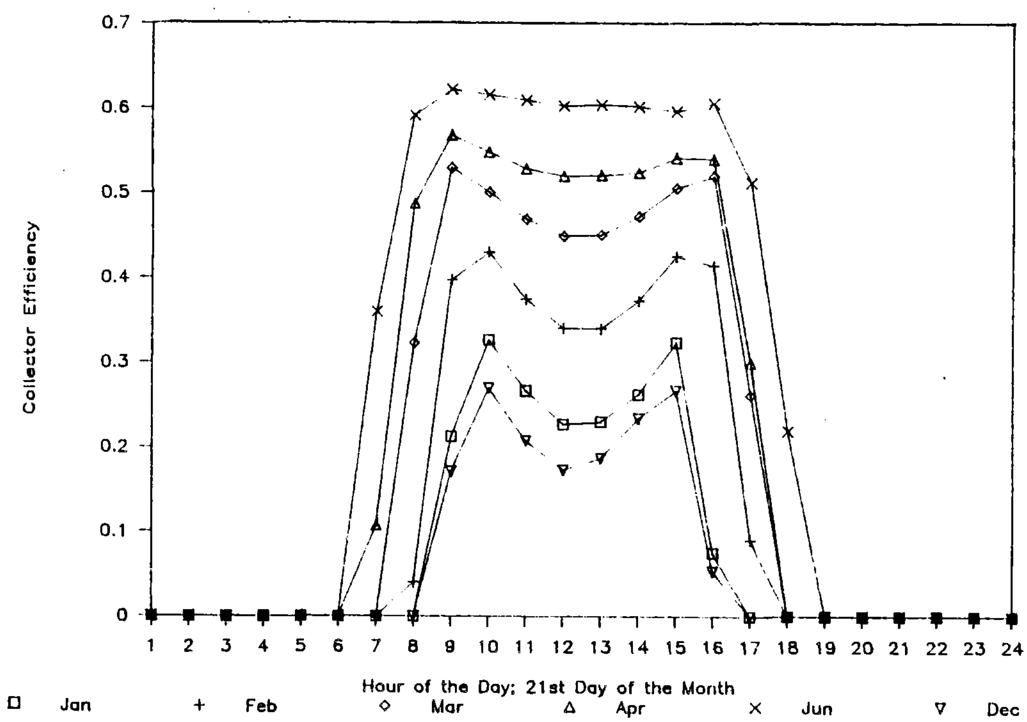

Figure A.14. Hourly Collector Efficiency for a Trough System with a North-South Layout and East-West Tracking

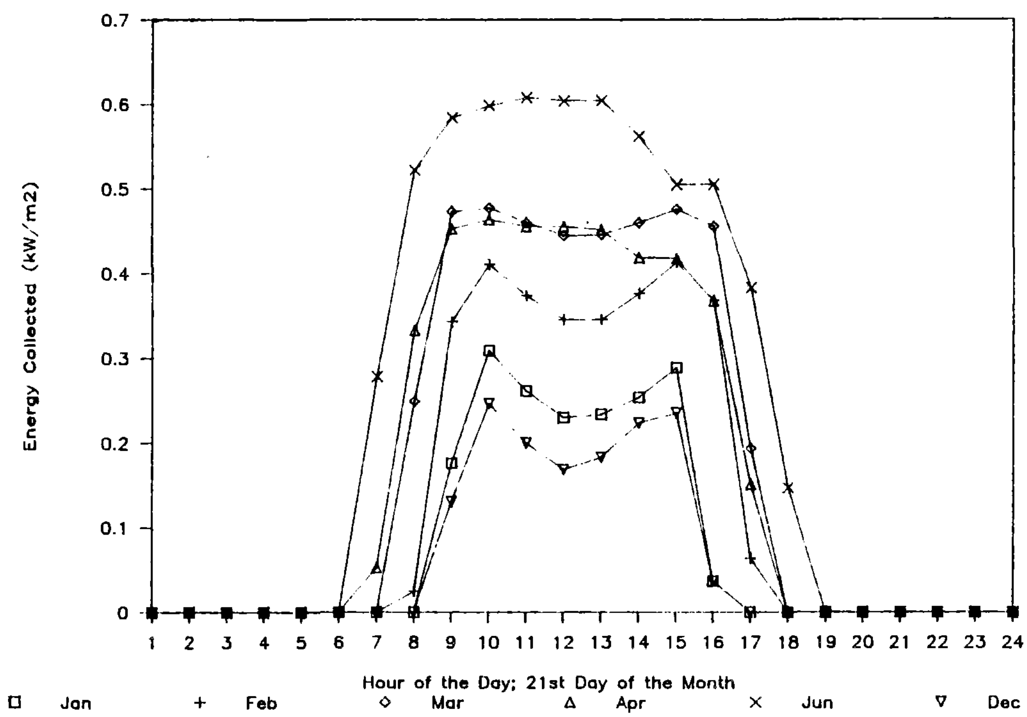

Figure A.15. Hourly Energy Collected for a Trough System with a North-South Layout and East-West Tracking less energy during the winter months, it puts out significantly more energy during the summer months. (See Figures A.12 and A.15 for a comparison of the hourly energy collection for the north-south and east-west axis trough systems in different months.)

Row-to-row shadowing is significant for a north-south axis system with a 50% packing factor as it reduces the morning and evening output from the system. The annual energy output is about 8%[a] less than it would be without row-to-row shadowing.

A.5 LEVELIZED ENERGY COST COMPARISON

Since capital and operating cost for the two trough layouts are assumed to be the same for fields of the same size (regardless of orientation), any performance differences cause the levelized costs to be different. There is a secondary effect however; since the east-west systems have lower annual energy output for any given field size, a larger field will be required to meet any given capacity factor with this orientation. Hence, the capital and operating costs will be higher with the east-west orientation.

Table A.5 shows the levelized energy cost for the trough systems with east-west and north-south orientations. The levelized energy costs for no-storage and 0.4 capacity factor plant across a range of plant sizes are presented in the table. In all cases, the north-south axis system has the lower projected levelized energy cost.

While it is true that north-south axis trough system has a higher annual energy output, and hence, a lower levelized energy output than the east-west orientation, the output of the north-south axis system is very peaky on a seasonal basis (Figures A.14 and A.15). Since the levelized energy costs of the two systems are so close, the selection of the preferred orientation would most likely be decided on the desired operating characteristics. If a trough

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(a) Sharp, J. K., and C. J. Chiang. 1983. "Siting Tradeoffs for Parabolic Trough Fields." In Proceedings of the Distributed Solar Collector Summary Conference -- Technology and Applications, ed. R. L. Alvis, pp. 32-42. Sandia National Laboratories, Albuquerque, New Mexico.

TABLE A.5. East-West Axis and North-South Trough Levelized Energy Costs

		Levelized Energy Cost (mills/kWh)	
	Plant Size, MW_e	No Storage	0.4 Capacity Factor
	0.5	759	500
	2.0	364	253
East-West	10.0	229	178
	30.0	202	168
	100.0	193	175
	0.5	657	498
	2.0	318	251
North-South	10.0	204	173
	30.0	180	163
	100.0	175	169

system were used in a summer-peaking utility, the north-south axis orientation, with its much higher summer output would be preferred. (This is the orientation that Luz has selected for its plants; Luz is a small power producer operating under avoided cost contracts and sells its power to Southern California Edison Company, a summer-peaking utility.) However, if a more level annual energy output were desired, the east-west axis system would be the preferred orientation.

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Cameron, C. P., and V. E. Dudley. 1986. Acurex Solar Corporation Modular Industrial Solar Retrofit Qualification Test Results, Sandia National Laboratories, Albuquerque, New Mexico.

APPENDIX B

LEVELIZED ENERGY COST CALCULATIONS

APPENDIX B

LEVELIZED ENERGY COST CALCULATIONS

This appendix provides a description of the levelized energy cost (LEC) approach to economic evaluation of solar thermal power plants. Levelized energy costs are life cycle costs that include a plant's capital cost, operation and maintenance cost, taxes, interest, and return on investment. An LEC approach provides an economically correct treatment of these costs and allows an equitable comparison of alternative solar thermal power systems.

In the following section, general economic principles relating to LEC calculations such as the time value of money, discount rate, and net present value are defined and explained. The appropriate use of LEC analyses for choosing between alternatives is discussed in Section B.2. Section B.3 provides an overview of the general approach to LEC calculations, and the final section presents key economic assumptions employed in this study.

B.1 General Economic Principles

The purpose of an economic evaluation is to select the best investment, i.e., the investment that maximizes the wealth of the investor. An economically correct methodology for comparing alternatives must properly consider (at a minimum) the time value of money and inflation. These concepts are discussed below.

The time value of money results from the fact that people prefer to consume goods immediately rather than at a later date. A lender forgoes the use of loaned money until it is later repaid. Lenders require compensation (in the form of interest) for postponing their consumption.

As a result of the time value of money, expenses or revenues (cash flows) which occur at different times cannot be directly compared on a face value basis. The most common way to correctly interpret cash flows occurring at different times is through a present value calculation. In a present value calculation, a discount rate compensates for the time value of money. The discount rate is the minimum rate of return that an investor is willing to accept from the investment; in the case of a lender, the discount rate is equivalent to the interest rate charged on the loan. Interest (discount) rates are a function of the intrinsic productivity of capital (or how much additional capital can increase output of goods and services), the expected inflation rate, and a risk premium having to do with the variability of the cash flows. The rate of constant dollar interest is the compensation for postponing consumption when there is no inflation. The greater the uncertainty in the timing or magnitude of a cash flow (risk), the higher the real interest (or discount) rate will be.

Inflation is another fundamental concept that has a significant impact on economic evaluations. Inflation is a decrease in the purchasing power of currency over time, and affects all the expenses and revenues associated with an investment. In periods of inflation, investors demand higher returns (higher discount rates) as compensation for postponing consumption because money received later will buy fewer goods and services than it will today.

Economic evaluations can handle inflation in one of two ways. The first approach is to include the effects of the expected inflation rate into all revenue and expense streams. This approach is called a nominal (or current) dollar method and results in estimates of the actual face-value cash flows to occur in each year. The second method of accounting for inflation is to exclude the effects of inflation from all cash flows. This approach is called a real (or constant) dollar method, because it expresses all cash flows in dollars of constant purchasing power. Either approach to inflation will yield a correct evaluation of energy alternatives. However, it is important that all the economic calculations be expressed consistently, i.e., either in nominal or real terms.

All possible investments of the same risk will not necessarily earn the same rate of return. Deciding which investment to select can be done by calculating the net present value. The net present value is the difference between the present value of the investment and the present value of the cash flows to be received. For an investment to be attractive, the net present value must be greater than zero. Selecting investments with negative net present values decreases wealth; conversely, selecting investments with positive net present values increases wealth. Businesses and individual investors attempt to maximize their wealth and select investments on this basis. Wealth maximization occurs when all positive NPV investments are chosen. When choosing between mutually exclusive investments (e.g., the energy source for a particular power plant) the alternative with the largest net present value will be the one that maximizes the wealth of the investor.

B.2 Using Levelized Energy Cost Analysis

Deciding between alternatives on the basis of capital cost, system efficiency, or any other single parameter will not necessarily yield the most economically efficient method or maximize the wealth of investors. The LEC approach is one economically correct method which can be used to appropriately choose between alternatives.

There are two important constraints in LEC calculations. The first is that a selection between alternatives using the LEC approach is only reasonable when the alternatives are providing equivalent service. If the characteristics or use of the energy systems are dramatically different (for instance, a peaking plant being compared to a base load plant), the LEC cannot be used by itself in deciding which alternative is better because the value of the energy produced by each plant may be dramatically different. The second constraint is that LEC comparisons are only appropriate when the economic assumptions used in the calculations are consistent. This constraint is especially important when comparing LEC calculations from different sources. The economic assumptions will substantially affect the magnitude of the LEC calculated, even though they may not alter a relative comparison of concepts. Using the LEC to compare technologies must be restricted to cases where the economic assumptions are equivalent.

B.3 Levelized Energy Cost Approach

Levelized energy cost analysis employs the concepts discussed above. But, since the result is given in terms of an energy cost, an LEC approach makes the results easier to understand when comparing energy alternatives. The economic result is the same, however. Selecting the lowest LEC from the possible alternatives which provide equivalent service maximizes the wealth of the investors. Thus, when making energy investments, businesses and individual investors will generally select the option with the lowest LEC even though it may not be the option with the highest thermodynamic efficiency.

There is a trade-off between cost and process or system efficiency. LEC calculations are able to correctly evaluate this trade off and will determine the most economically efficient method.

An LEC is simply an annualized cost divided by an annual energy output. The annualized cost is defined as a hypothetical uniform cost stream which, over the plant's life, has the same present value as all of the actual plant costs. The general steps involved in calculating an LEC (assuming that the annual energy output and all plant costs are known) are: 1) calculate the capital recovery factor and fixed charge rate(s), 2) calculate present values for all cost streams, and 3) calculate annualized costs and levelized energy cost. These steps are discussed in more detail below.

The annualized cost is made up of capital costs and recurring costs. Because the tax laws treat these costs differently, they must be considered separately in the LEC analysis. The present value of all recurring costs must be multiplied by a capital recovery factor (CRF) to yield a single annual cost that represents all recurring costs over the life of the plant. This single annual cost is equivalent to the payment on a loan with the principle amount equal to the present value of all the recurring costs. The CRF is calculated as:

$$CFR = \frac{k}{1 - (1 + k)^{-N}} \qquad (1)$$

where k = Discount rate
N = Plant lifetime

The contribution of the capital costs to the annualized cost is the product of the present value of the capital construction costs and the fixed charge rate (FCR). The FCR accounts for income taxes (including depreciation and investment tax credit effects), return on equity, interest on debt, insurance, property taxes and other taxes. The FCR is calculated as:

$$FCR = CRF * \left[\frac{1 - t * (DPF) - itc}{1 - t}\right] + p \qquad (2)$$

where CRF = Capital Recovery Factor

t = Effective income tax rate

DPF = Depreciation Factor (defined below)

itc = Investment tax credit

p = Insurance and effective property and other tax rate

The depreciation factor is calculated from the formula:

$$DPF = \sum_{i=1}^{n} \frac{dp_i * \left(1 - \frac{itc}{2}\right)}{(1 + k)^{i-1}} \tag{3}$$

where dp_i = Depreciation fraction allowed in year i

i = Year relative to year 0 (the last year of construction)

itc = Investment tax credit

k = Discount rate

n = Depreciation Lifetime

The reference time period for the present value calculation in Equation 3 and the other present value calculations is year 0, the last year of plant construction. The choice of the year to use as the basis for present value calculations is a matter of convention. Equation 6 assumes that the plant construction is completed at the end of a tax year, so the value of the first years depreciation is not discounted. The values of dpi are determined from Accelerated Cost Recovery System (ACRS) depreciation schedules for the appropriate tax life of the investment. The tax life depends upon both the type of property and the ownership. ACRS depreciation schedules are summarized in Table B.1.

TABLE B.1. ACRS Depreciation Schedules (Percentage Depreciation in Each Year)

	Depreciation Lifetime		
YEAR	5 YEAR	10 YEAR	15 YEAR
1	15	8	5
2	22	14	10
3	21	12	9
4	21	10	8
5	21	10	7
6		10	7
7		9	6
8		9	6
9		9	6
10		9	6
11			6
12			6
13			6
14			6
15			6

A special FCR is used for land because land cannot be depreciated for tax purposes. The land FCR is calculated as:

$$FCRL = \frac{CRF}{1 - t} + p \qquad (4)$$

where CRF = Capital Recovery Factor

t = Effective income tax rate

p = Effective property and other tax rate

The next step to calculating the LEC is to determine the actual cash flows (nominal dollars) of all capital costs, including costs for indirect and contingency costs. Each years construction cash flow can be calculated as:

$$C_i = CAP_b * FR_i * (1 + gc)^{i-b} \qquad (5)$$

where C_i = Capital cost expended in year i

i = Year relative to year 0 (the last year of construction)

CAP_b = Total plant capital cost estimate in year b

b = Base year for capital cost estimate relative to year 0

FR_i = Fraction of CAPb intended to be spent in year i

gc = Capital cost escalation rate

The present value of all capital construction costs can then be calculated as:

$$PCV = \frac{C_i}{(1 + k)^i} \qquad (6)$$

where C_i = Capital cost in year i

i = Year relative to year 0 (the last year of construction)

k = Discount rate

The present value of land cost (assuming land is resold at the end of the plants life) can be calculated as:

$$PVL = \frac{LC_b * (1 + gl)^{1-b}}{(1 + k)^i} - \frac{LC_b * (1 + gl)^{N-b}}{(1 + k)^N} \qquad (7)$$

where LC_b = Land cost estimate in year b

gl = Land escalation rate

i = Year land purchased relative to year 0

b = Year of land cost estimate relative to year 0

k = Discount rate

N = Plant lifetime

The next step is to calculate the present value of all operations and maintenance (O&M) costs, PVO:

$$PVO = (1 + go)^{-b} * OM_b * \left(\frac{1 + go}{k - go}\right) * \left[1 - \left(\frac{1 + go}{1 + k}\right)^N \right] \qquad (8)$$

where g_o = O&M escalation rate
b = Base year for O&M cost estimate relative to year 0
OM_b = O&M annual estimate in year b without allowing for escalation
k = Discount rate
N = Plant lifetime

None of the solar thermal plants in this study required fuels. For plants that require fuel (such as hybrid plants), the present value of fuel costs would be calculated as:

$$PVF = (1 + g_f)^{-b} * F_b * \left(\frac{1 + g_f}{k - g_f}\right) * \left[1 - \left(\frac{1 + g_f}{1 + k}\right)^N\right] \qquad (9)$$

where gf = Fuel escalation rate
b = Base year for fuel cost estimate relative to year 0
F_b = Fuel annual estimate in year b without allowing for escalation
k = Discount rate
N = Plant lifetime

The annualized cost of the plant (expressed in year b dollars) can then be calculated as:

$$AC = (1 + g_i)^b * \{FCRL * PVL + FCR * PVC + CRF * (PVO + PVF)\} \qquad (10)$$

where AC = Annualized cost in year b dollars
b = Base year for costs relative to year 0

The LEC is then calculated as:

$$LEC = \frac{AC}{A_{out}} \qquad (11)$$

where LEC = Levelized energy cost
AC = Annualized cost
A_{out} = Annual energy output in appropriate units

The LEC calculations in this study were carried out on a real dollar basis. Levelized energy cost comparisons can be made on the basis of either real or nominal dollars. A real dollar LEC is a energy cost which is level over time in dollars of constant purchasing power; a nominal dollar LEC is level over time in the actual dollars of each year. Nominal dollar LEC calculations are always numerically higher (for any positive inflation rate) than real dollar LEC calculations because general inflation over the plants lifetime is included in the energy cost.

The real dollar LEC is obtained first by calculating the nominal dollar LEC (Equation 11) and then converting for inflation. This conversion is done by the formula:

$$LEC_r = \frac{LEC_n}{CRF} * \frac{(k - G_i)}{(1 + G_i) * \left(1 - \frac{(1 + G_i)}{(1 + k)}\right)^N} \qquad (12)$$

where LEC_r = Real dollar LEC

LEC_n = Nominal dollar LEC

CRF = Capital Recovery Factor

k = Discount rate

G_i = General inflation rate

N = Plant lifetime

An alternative approach to calculating the real dollar LEC would be to express all of the economic inputs in real terms. This approach is somewhat less desirable since it will not account for inflation lessening the value of depreciation (which reduces tax payments) in future years.

B.4 ECONOMIC ASSUMPTIONS

The economic assumptions used in this study are presented in Table B.2.

TABLE B.2. Power Plant Economic Ground Rules

Parameter	Assigned Value
Price year	1984
Real after tax cost of capital	3.15%
General Inflation Rate	4%
Investment tax credit	10%
Effective income tax rate	50%
Plant economic life	30 years
Depreciation life	10 years (ACRS)
Property and other taxes	1%
Construction period	0.5 and 2 MWe - 1 year 10 Mwe - 2 years 30 and 100 Mwe - 3 years

APPENDIX C

PLANT PERFORMANCE RESULTS

APPENDIX C

PLANT PERFORMANCE RESULTS

This appendix presents additional information on the annual energy output for each technology. The total energy produced by the plant which reaches the utility grid is the result of individual component efficiencies (annual component efficiencies are discussed in Chapter 5), general plant energy losses, and losses due to plant availability. These losses can be summarized in an efficiency "water fall" diagram. This appendix presents a number of efficiency water fall diagrams for the concepts analyzed.

C.1 PLANT ENERGY LOSS MECHANISMS

It is possible to define component and system efficiencies for solar thermal plants in many different ways. This section presents definitions of the major energy loss mechanisms shown in the water fall efficiency diagrams. All of the component energy losses are calculated on an annual basis.

C.1.1 Concentrator Losses

Losses included in the concentrator annual efficiency include all losses from the time immediately before the insolation impinges on the concentrator surface to the time immediately before the concentrated energy impinges on the receiver (either the receiver cover glass or receiver heat transfer surface). The energy potentially available to the concentrator system is calculated as the product of the annual direct normal insolation times the concentrator aperture area. This definition includes any insolation occurring at sun angles which prevent use by the concentrator (such as low sun angles for central receiver concepts) as a concentrator loss. When comparing concentrator (or receiver) efficiency calculations from different sources, it should be remembered that many estimates define concentrator efficiency based on the insolation that can actually be used by the concentrator; this type of definition can result in misleading concentrator efficiencies which are unrealistically high.

Loss mechanisms included in the concentrator efficiency include geometric optics (cosine losses, blocking, shadowing, and atmospheric attenuation), glass reflectivity, reflectivity degradation (due to dirt and long term permanent losses), solar tracking errors, and receiver spillage.

C.1.2 Receiver Losses

Losses included in the receiver annual efficiency consist of all losses which occur from the time flux impinges on the receiver control volume (the receiver aperture, cover glass or heat transfer surface) until the thermal energy is transferred away from the receiver in a working fluid. The total energy potentially available to the receiver is the annual flux delivered from the concentrator field (incident insolation less all concentrator losses). Receiver losses include reflective losses and thermal losses due to radiation, convection, and conduction. An important aspect from the standpoint of characterizing annual performance is that receiver thermal losses continue even in no-insolation periods until the receiver reaches ambient temperature; an example is night time cool down. Receiver thermal losses during periods with no insolation result in potentially useful energy being used to warm the receiver to operating temperature when the plant next starts operation.

C.1.3 Transport Losses

Thermal transport subsystems include losses from the time thermal energy is absorbed in the working fluid at the receiver to the time the thermal energy is delivered to either the storage subsystem or energy conversion subsystem. The total input energy to the thermal transport system is the annual energy absorbed by the working fluid in the receiver. For thermal transport systems, losses include only the heat losses from the piping; parasitic losses due to pumping power requirements and any heat tracing requirements are accounted for in plant parasitics. For electric energy transport systems, the efficiency includes the effect of losses between the distributed generators and the point where the plant exports power to the grid. The total energy input for an electric energy transport system is the annual energy output from all distributed generators.

C.1.4 Conversion Mismatch Losses

Conversion mismatch losses account for any thermal energy which exceeds the maximum input rate to the heat engine and therefore cannot be used to produce energy. For systems without thermal energy storage, conversion mismatch losses occur any time collected energy from the field would exceed the current (based on ambient conditions) full load input requirements of the heat engine. Systems with thermal energy storage can dispatch energy to storage when power from the field exceeds the maximum heat engine input, and so have more flexibility in reducing conversion mismatch losses. For systems with thermal energy storage, conversion mismatch losses would occur only after storage had been fully charged and the thermal input requirements of the heat engine were exceeded. Conversion mismatch losses could be avoided entirely by selecting a heat engine with a maximum thermal input equal to the maximum thermal output from the collector field; however, such an approach does not represent a cost effective plant design strategy.

C.1.5 Storage Losses

Performance of thermal storage subsystems includes thermal losses from the time thermal energy is delivered to the input heat exchanger (or storage tank itself if an input heat exchanger is not required) to the time energy is removed through the output heat exchanger. The total input energy to the thermal storage system is the annual energy delivered by the transport system to the storage system (note that in some designs, such as the Central Receiver Water-Steam system, that not all energy from the transport system will go through the storage subsystem). For thermal storage subsystems, losses in the storage system consist of thermal losses from storage tanks and heat exchangers. Losses due to pumping power requirements and heat tracing are accounted for separately in plant parasitics. For electric energy storage systems, the efficiency calculated includes losses from AC/DC conversion, net efficiency in battery storage, and DC/AC conversion. The total energy input for an electric energy transport system is the annual energy output from all distributed generators that is sent to storage rather than being sent directly to the grid.

C.1.6 Heat Engine Start Up Losses

This category of losses includes all the thermal energy used to initially warm the heat engine, ramp it to full speed, and bring it into synchronization with the grid.

C.1.7 Conversion Losses

Energy conversion efficiency includes all losses related to the thermodynamic performance of the heat engine, heat rejection equipment, and the generator. The heat engine efficiency reported in this report is an operating efficiency, which is calculated based on the actual energy delivered to the heat engine during operating periods; losses during start up and due to conversion mismatch are accounted for in the above categories. Conversion losses do not include parasitic power requirements for the heat engine, which are included with plant parasitics.

C.1.8 Plant Parasitics Losses

These losses include the electric power requirements for the solar plant both during operational periods and periods when the plant is shut down. These parasitics include:

- Heat Engine- Rankine cycle heat engine parasitics include the feed pump, condensate pump, circulation water pump, condenser vacuum pump, turbine controls, bearing cooling water, gland seal condenser, and cooling tower fans. For the Stirling engines the parasitics account for cooling fan power requirements.
- Energy Storage- Parasitics include storage input and output pumps for thermal storage systems, and any heat tracing requirements. Electric energy losses for electric storage systems are accounted for in the storage efficiency and not as parasitics.
- Energy Transport- Parasitics for thermal transport systems include power required for the main field circulation pump (and any booster pumps) and for field recirculation pumps (used in water-steam systems to recirculate condensate). Where required, parasitic loads for transport heat tracing are also included. Electric energy losses for electric transport systems are accounted for in the storage efficiency and not as parasitics.
- Miscellaneous Operating Parasitics- These include concentrator tracking power requirements, water treatment system, service water system, HVAC and master control system.
- Standby Parasitics- Standby power requirements are incurred while the plant is not operating. They include any concentrator standby

power and receiver circulation power requirements, receiver heat tracing, turbine bearing cooling water, service water, cooling tower fan (for seal steam), HVAC, lighting, plant control system, and any miscellaneous uses.

C.1.9 Turbine Standby Losses and Plant Availability

Turbine standby losses are electrical parasitic power requirements associated with the Rankine cycle heat engine standby requirement including turbine turning power, circulation pumps for standby steam, and gland seal steam.

Plant availability losses represent the loss of output caused by scheduled and unscheduled plant outages.

C.2 Plant Energy Loss Diagrams

This section shows the various loss mechanisms associated with each plant design are summarized on a series of efficiency "water fall" charts. The "water fall" charts show the impact of the significant losses on annual performance. For example, Figure C.1 is an efficiency "water fall" chart for a 2 MWe central receiver molten salt system without storage. The bar on the left shows the total annual energy available in the insolation which could strike the concentrators if they were always directly oriented toward the sun through the entire year. The bars to the right show the impact of various loss mechanisms on the useful energy. The definition of the loss mechanisms has been given above, but the actual presentation of losses associated with the storage needs further discussion. Clearly, storage losses only apply to energy which passes through the storage subsystem; consequently the bar entitled "storage" does not actually indicate the efficiency of the storage system, but rather the ratio of energy losses from storage. The annual losses from storage depend upon both the efficiency of storage and the amount of energy which is dispatched to storage. This results in no losses being reported from storage for the no-storage cases.

Four "water fall" diagrams are presented for each of the concepts. Two diagrams represent the performance of a 2 MWe plant, while the other two represent the performance of a 100 MWe plant. In each case, one diagram presents the results for a no-storage case, while the second presents the results for a plant with a capacity factor of 0.4.

C.2.1 Molten Salt Cavity Central Receiver with Salt Storage

The performance of the CR-Salt system is summarized on figures C.1 through C.4. Figure C.1 presents the results for the 2 MWe plant without storage. The major loss mechanisms are the concentrator losses, mismatch losses, and energy conversion losses. The high mismatch losses result from the concentrator field being excessively large from a performance standpoint, which means that much of the collected energy can neither be used directly in the heat engine or be used to charge storage. While large mismatch losses would seem to imply that the design is not optimum, the design selection was based on economic factors and not on just plant annual performance. Figure C.2 shows the results for the 0.4 capacity factor case. The main difference between this case and the 2 MWe no-storage case is the reduction of the mismatch losses through the use of energy storage. Figures C.3 and C.4 present the results for the 100 MWe cases. When compared to the 2 MWe cases, the 100 MWe designs have substantially improved receiver efficiency and energy conversion efficiency, but also demonstrate a slight reduction in start-up efficiency.

C.2.2 Sodium External Central Receiver with Sodium Storage

The performance of the CR-Na system is summarized on figures C.5 through C.8. Figure C.5 presents the results for the 2 MWe plant without storage. The major loss mechanisms are the concentrator efficiency, receiver efficiency, mismatch losses, and conversion efficiency. Figure C.6 presents the same results for the 2 MWe case with a capacity factor of 0.4, and shows dramatic improvements in the amount of energy lost through mismatch. Figures C.7 and C.8 show the same results for the 100 MWe case. When compared to the 2 MW_e cases, there is a substantial improvement in concentrator, receiver, and energy conversion efficiency. When compared to the molten salt designs, the sodium concepts at the 2 MW_e plant size have substantially lower concentrator and receiver efficiencies, which is caused by both the very small size of the sodium receiver and the fact that the molten salt receiver uses a cavity design with a north field. A north field tends to be more efficient than a surround field because of the lower cosine losses. At the 100 MW_e size, the sodium system is only slightly less efficient than the molten salt system.

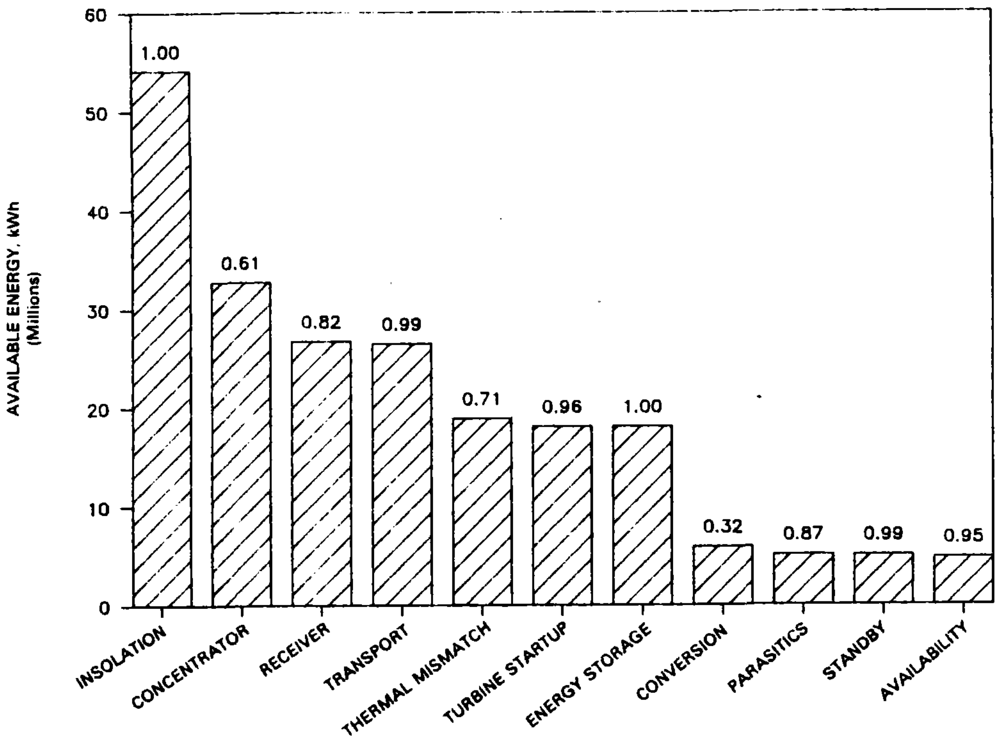

Figure C.1 Annual Energy Losses for a CR-Salt System with a No-Storage Capacity Factor in a 2 MWe Plant (19,000 m^2 field)

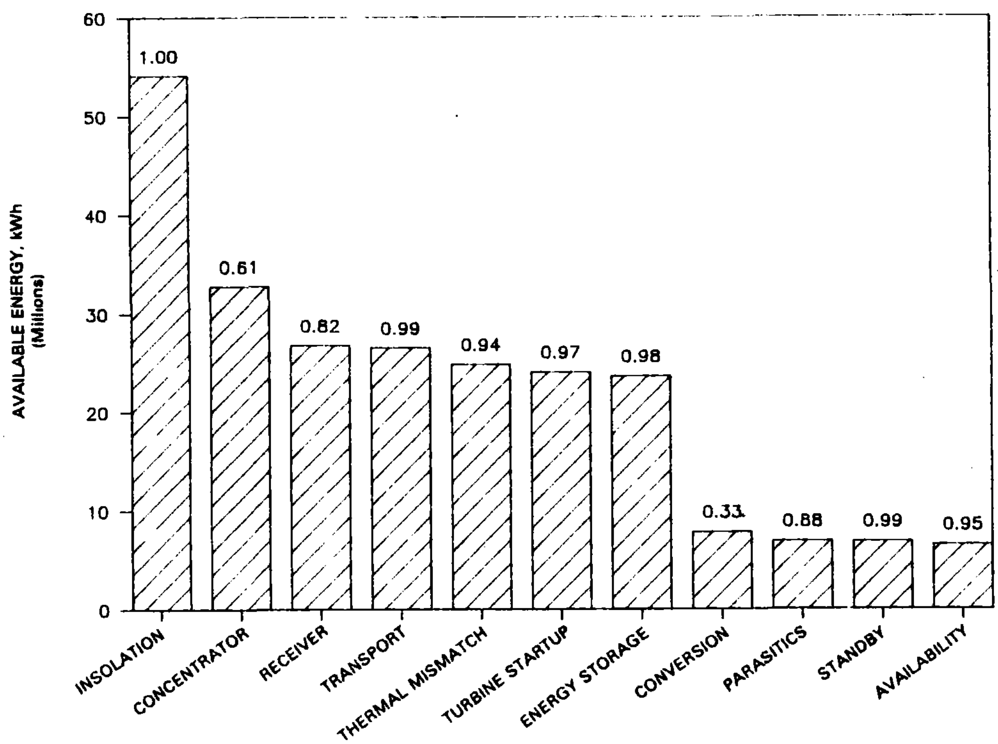

Figure C.2 Annual Energy Losses for a CR-Salt System with a 0.4 Capacity Factor in a 2 MWe Plant (20,000 m^2 field)

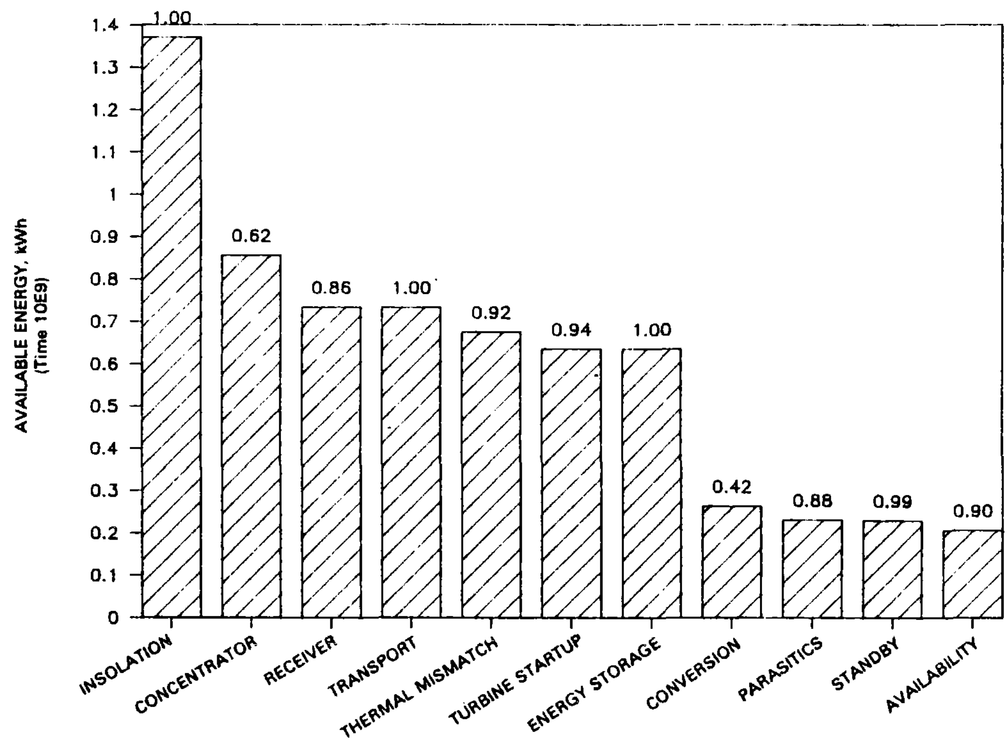

Figure C.3 Annual Energy Losses for a CR-Salt System with a No-Storage Capacity Factor in a 100 MWe Plant (481,000 m^2 field)

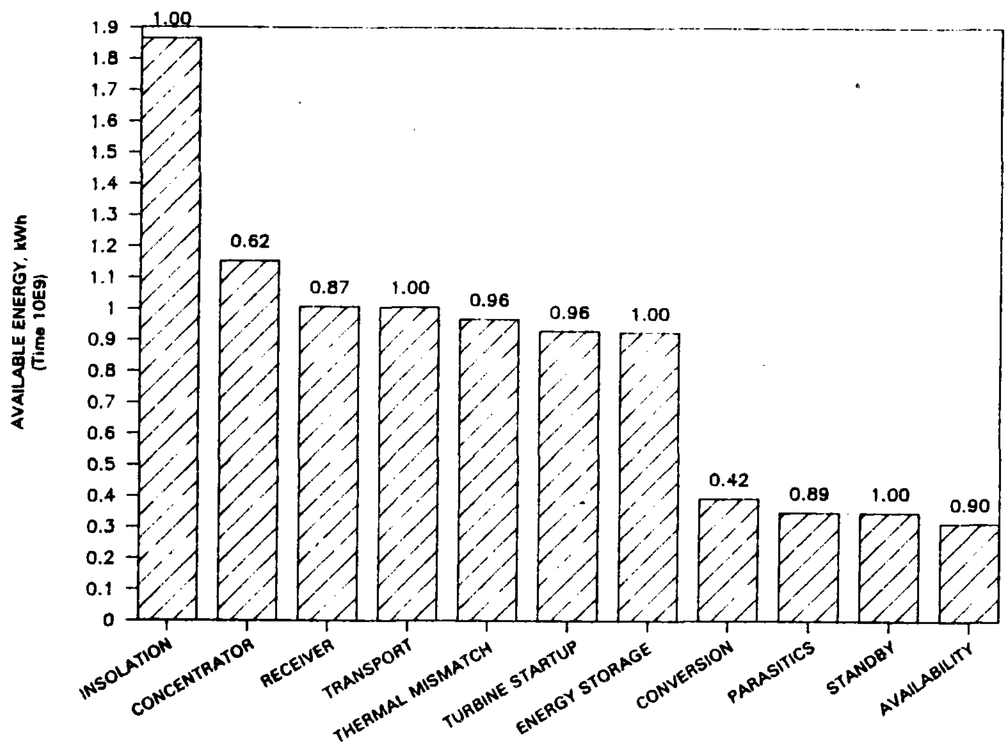

Figure C.4 Annual Energy Losses for a CR-Salt System with a 0.4 Capacity Factor in a 100 MWe Plant (733,000 m^2 field)

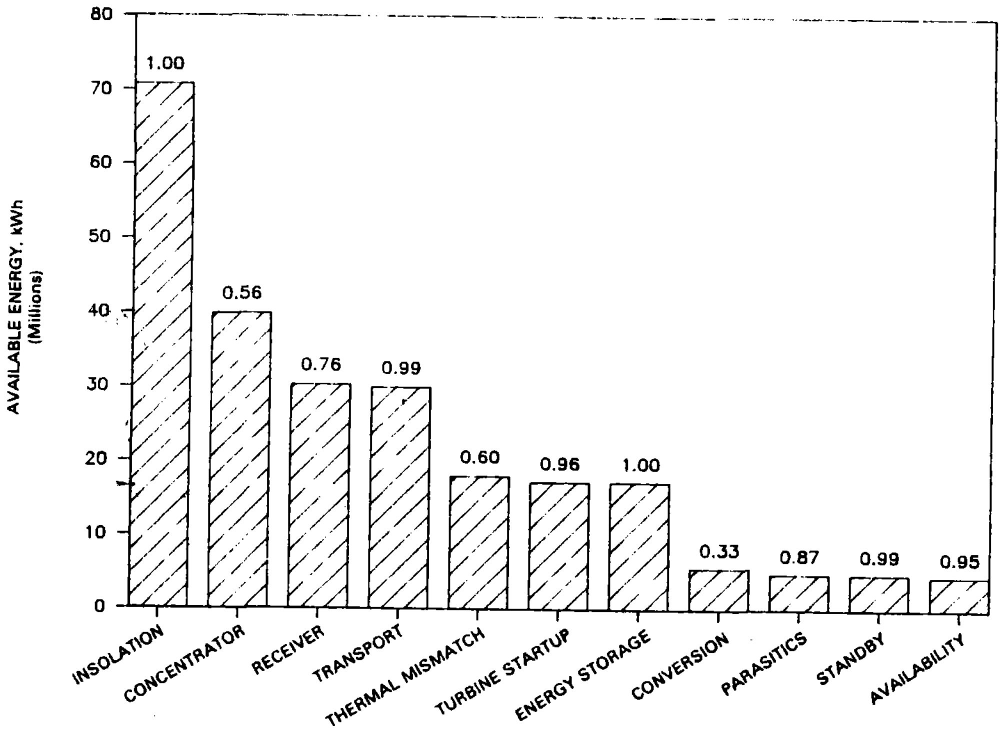

Figure C.5 Annual Energy Losses for a CR-Na System with a No-Storage Capacity Factor in a 2 MWe Plant (25,000 m^2 field)

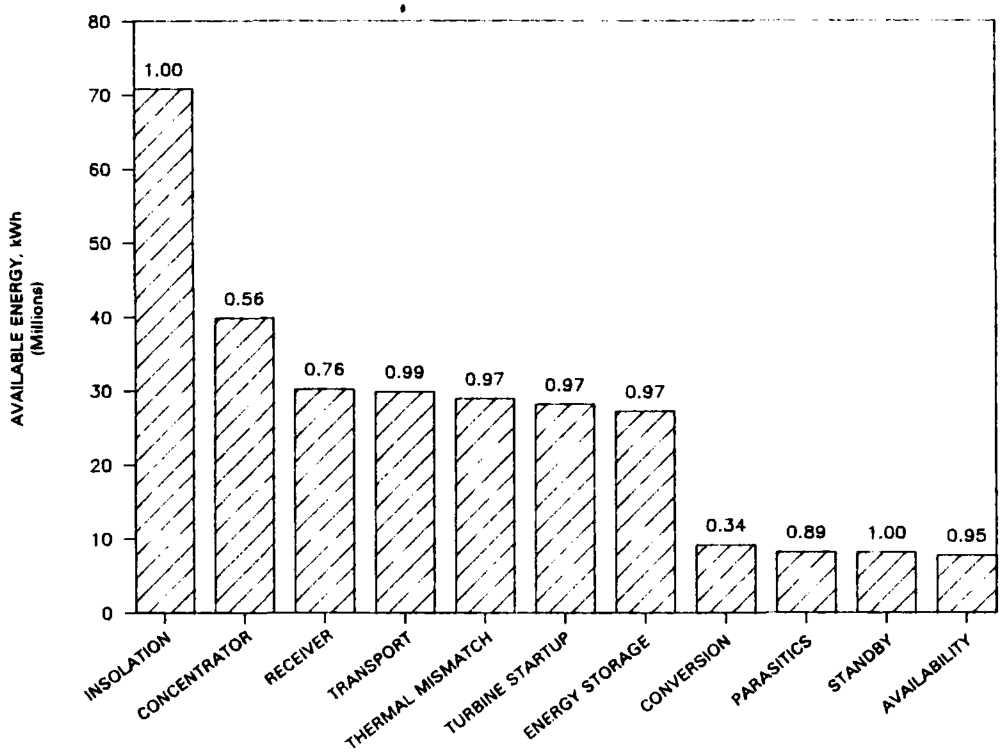

Figure C.6 Annual Energy Losses for a CR-Na System with a 0.4 Capacity Factor in a 2 MWe Plant (23,000 m^2 field)

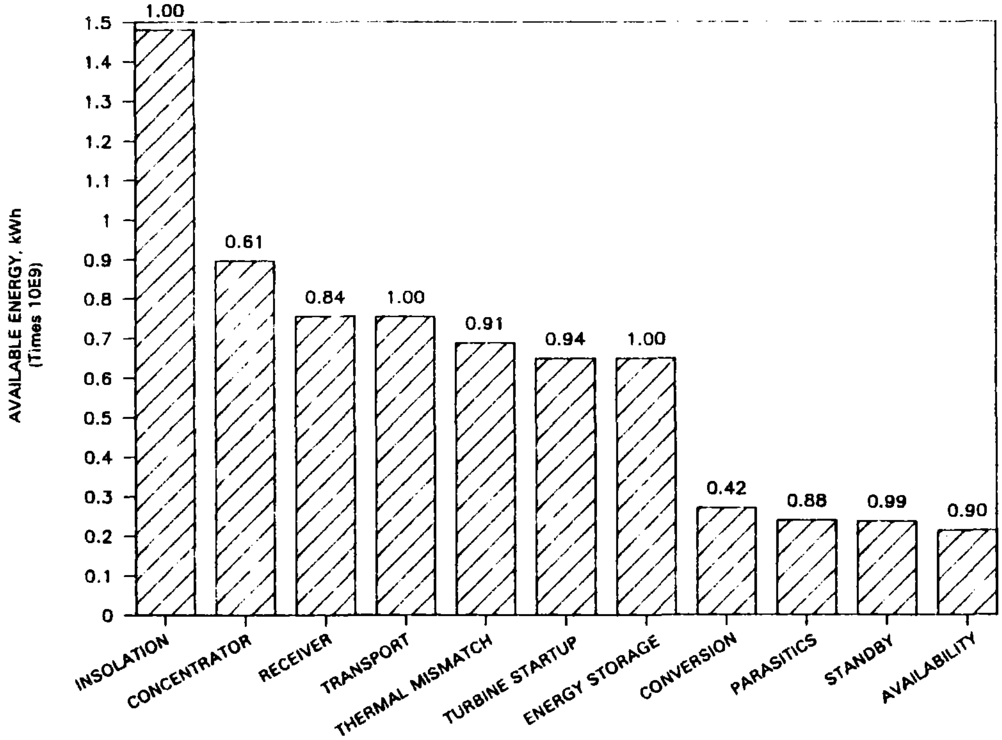

Figure C.7 Annual Energy Losses for a CR-Na System with a No-Storage Capacity Factor in a 100 MWe Plant (520,000 m^2 field)

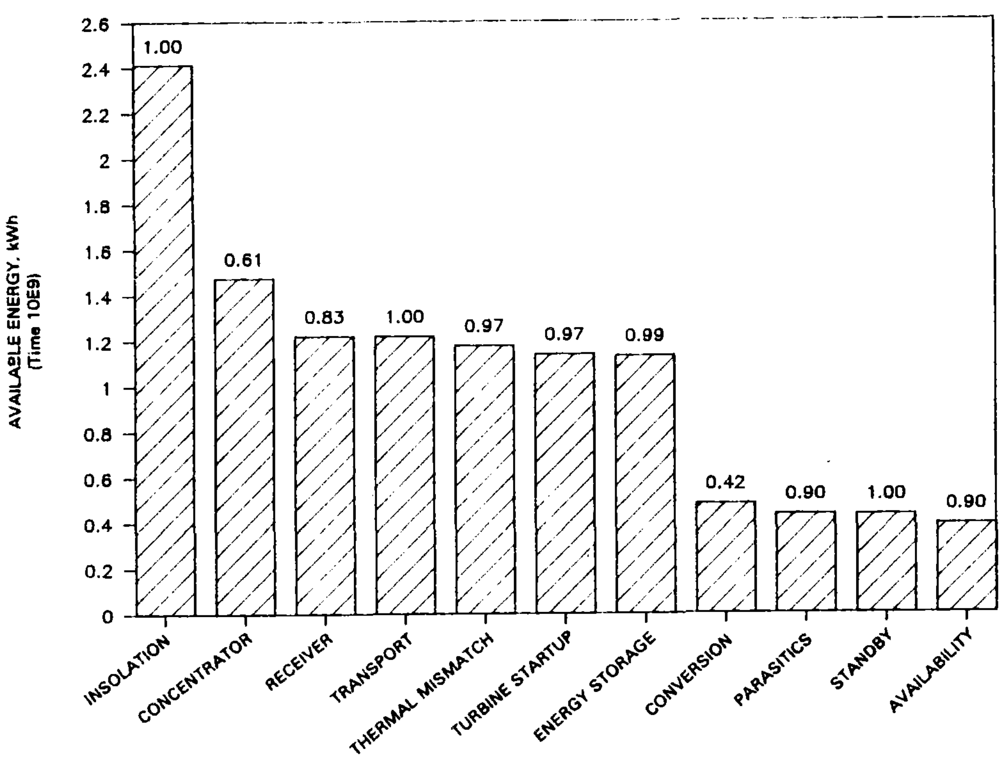

Figure C.8 Annual Energy Losses for a CR-Na System with a 0.4 Capacity Factor in a 100 MWe Plant (773,000 m^2 field)

C.2.3 Sodium External Central Receiver with Salt Storage

The performance of the CR-Na/Salt system is presented on figures C.9 through C.12. The results are essentially identical to the results for the central receiver system with sodium for both transport and storage. Parasitic power requirements are slightly lower for this system than for the sodium central receiver case because the sodium from the receiver is contained in a separate loop from storage, therefore the elevation head resulting from pumping sodium up the tower does not have to be dissipated in an expansion valve. This reduces the pumping power requirements.

C.2.4 Water/Steam Central Receiver with Oil/Rock Storage

The performance of the central receiver system with water/steam transport and oil/rock storage is presented on Figures C.13 through C.16. Figure C.13 presents the results for the 2 MW_e design without storage. The major loss mechanisms are concentrator, receiver, mismatch and energy conversion efficiency. Figure C.14 presents the same results for the 2 MW_e case with a capacity factor of 0.4. The results for the 100 MW_e cases are presented on Figures C.15 and C.16. When compared to the 2 MW_e designs, the 100 MW_e designs show a substantial improvement in concentrator, receiver, and energy conversion efficiency. The improvements in concentrator and receiver efficiency are caused by the excessive losses associated with the combination of large heliostats and small receiver size at the 2 MW_e power level. When compared to the molten salt central receiver concept, the water/steam system shows reduced concentrator, receiver, and energy conversion efficiencies. The impact of oil/rock storage on energy conversion efficiency is clearly shown by comparing the conversion efficiency of the 100 MW_e no storage case with the 100 MW_e case with a capacity factor of 0.4. The conversion efficiency drops from 40 percent to 35 percent, which is caused the degradation of turbine inlet steam conditions related to using oil at 580° F to generate steam.

C.2.5 Parabolic Dish with Stirling Engine Conversion

The performance of the dish system is summarized on figures C.17 through C.20. There is little difference between any of the figures. This shows the relative insensitivity of the Dish/Stirling system performance to plant size. The major variation between cases is caused by adding storage, which results

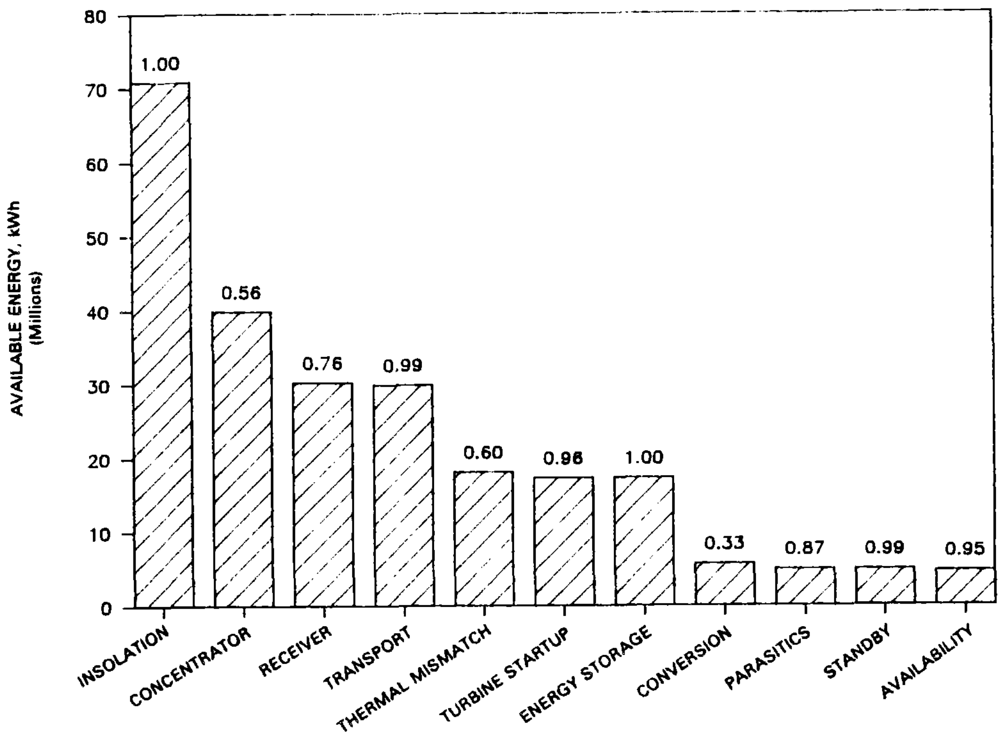

Figure C.9 Annual Energy Losses for a CR-Na/Salt System with a No-Storage Capacity Factor in a 2 MWe Plant (25,000 m^2 field)

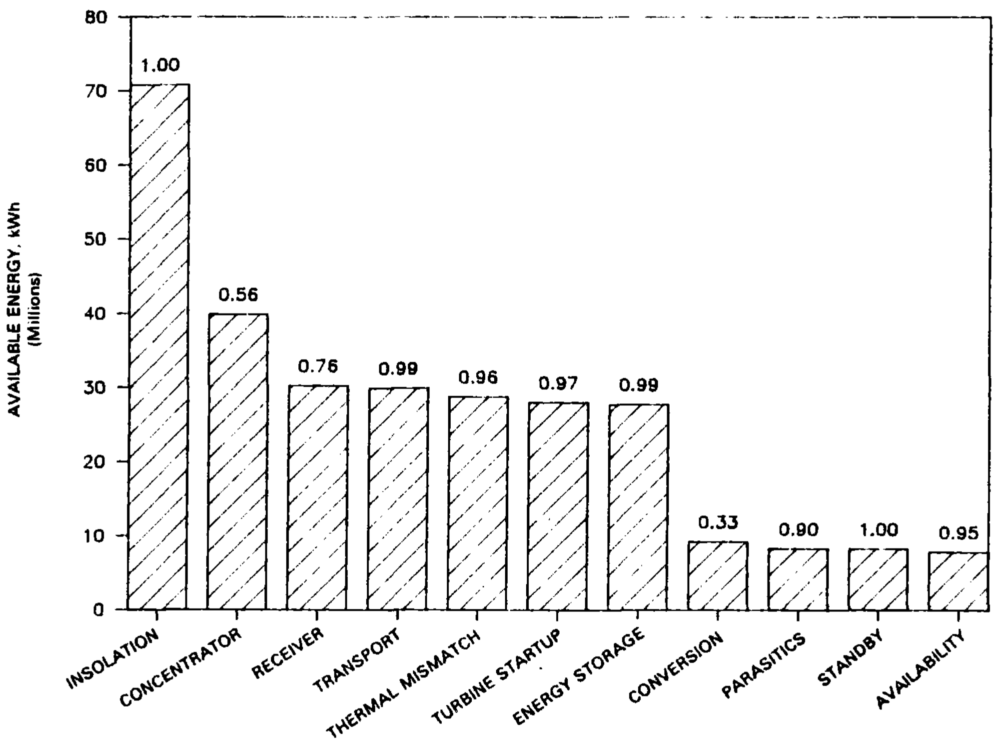

Figure C.10 Annual Energy Losses for a CR-Na/Salt System with a 0.4 Capacity Factor in a 2 MWe Plant (24,000 m^2 field)

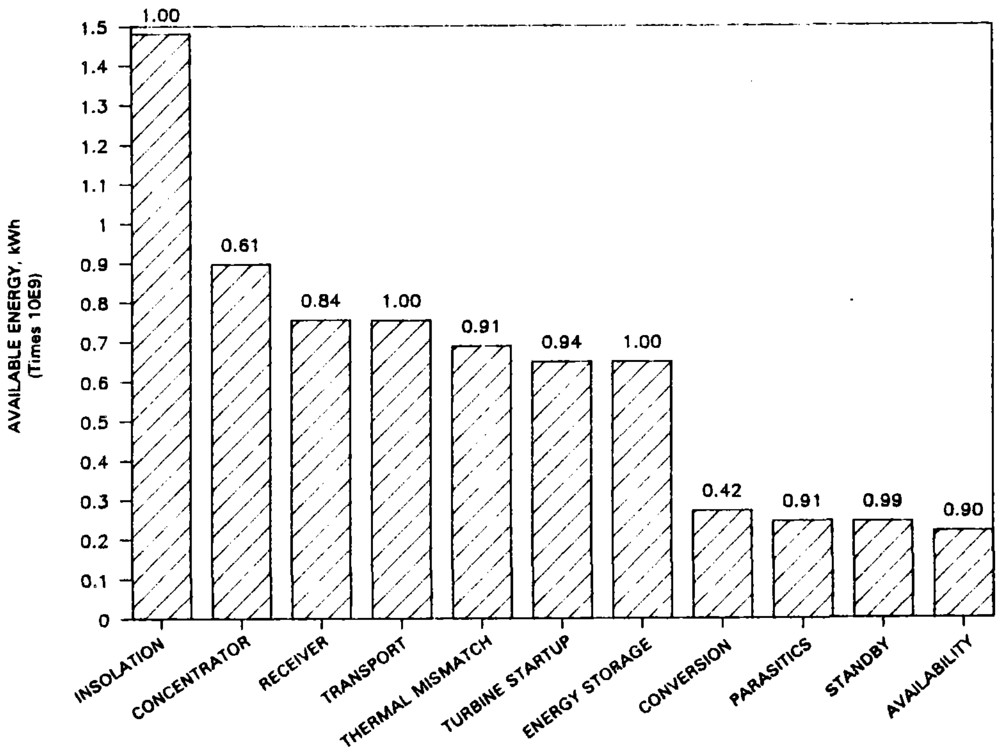

Figure C.11 Annual Energy Losses for a CR-Na/Salt System with a No-Storage Capacity Factor in a 100 MWe Plant (520,000 m^2 field)

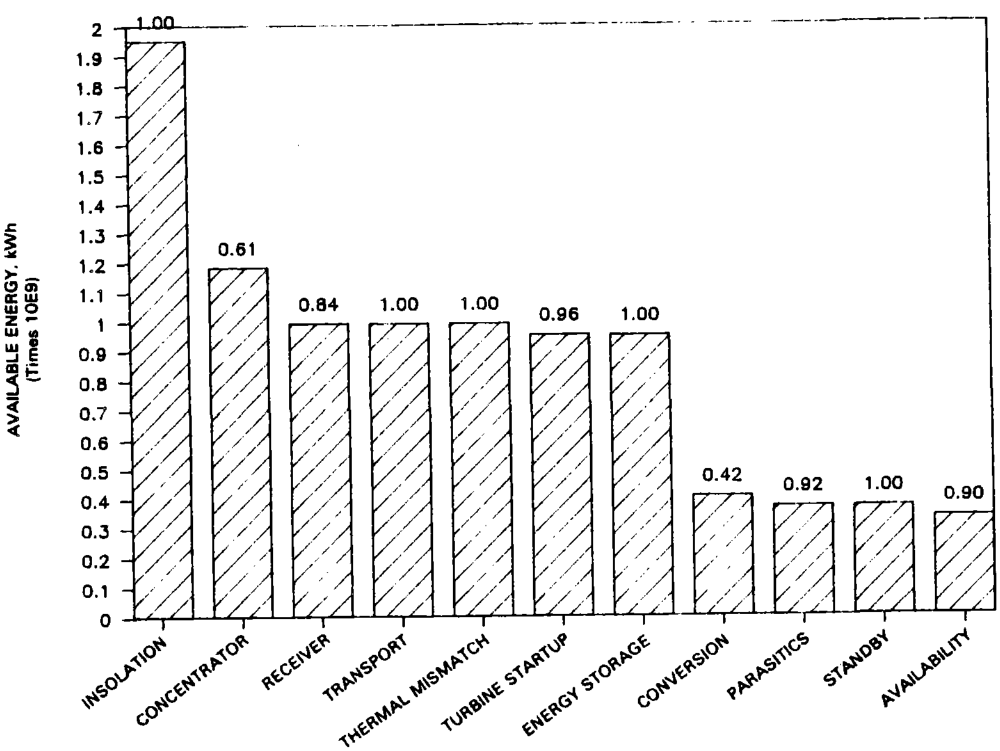

Figure C.12 Annual Energy Losses for a CR-Na/Salt System with a 0.4 Capacity Factor in a 100 MWe Plant (724,000 m^2 field)

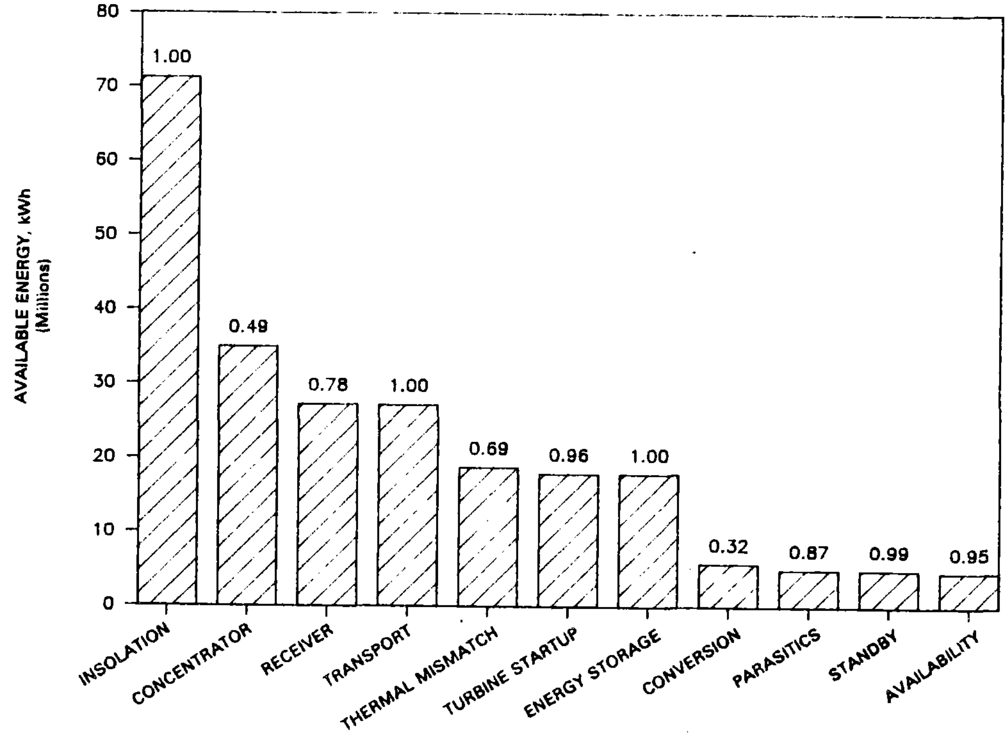

Figure C.13 Annual Energy Losses for a CR-W/S_2 System with a No-Storage Capacity Factor in a 2 MWe Plant (25,000 m^2 field)

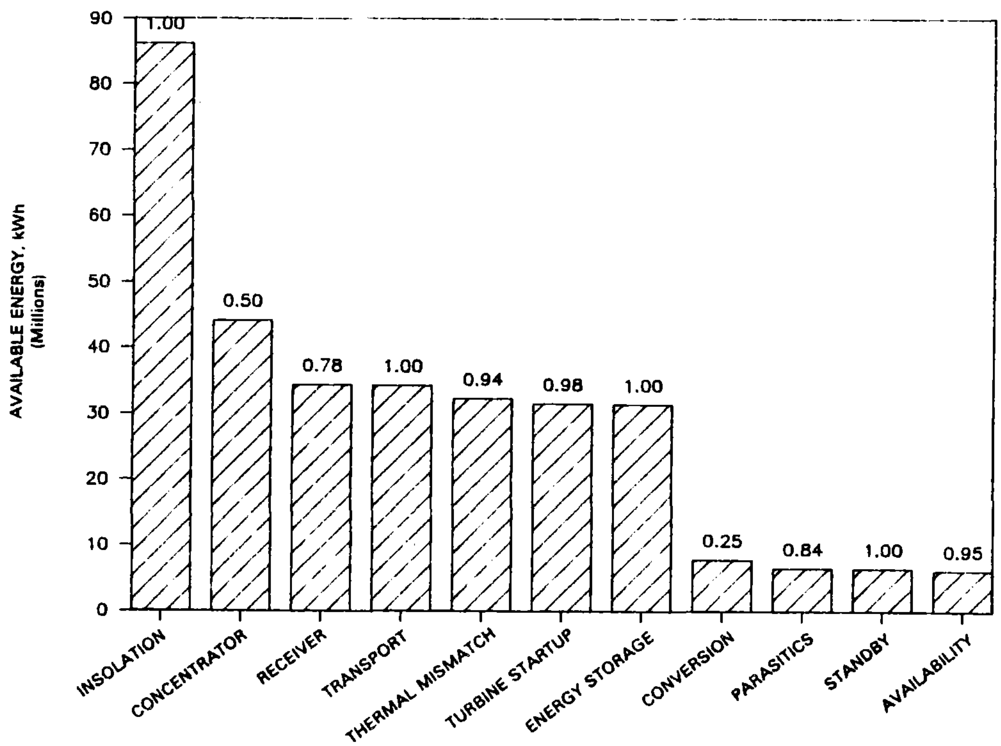

Figure C.14 Annual Energy Losses for a $_2$CR-W/S System with a 0.4 Capacity Factor in a 2 MWe Plant (28,000 m^2 field)

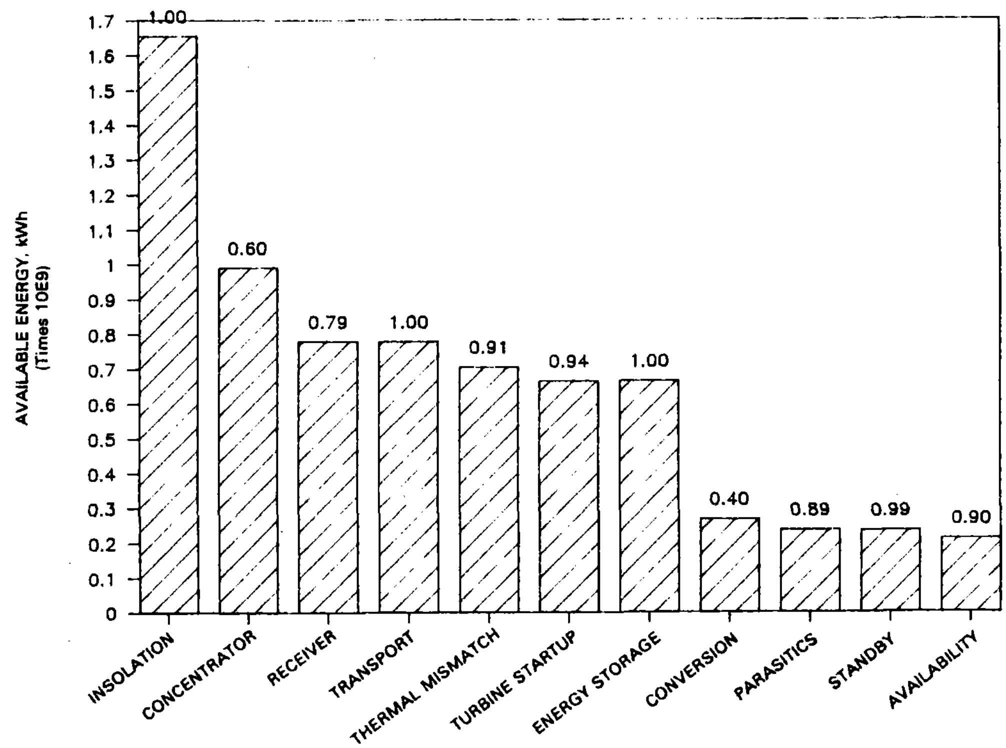

Figure C.15 Annual Energy Losses for a CR-W/S System with a No-Storage Capacity Factor in a 100 MWe Plant (581,000 m^2 field)

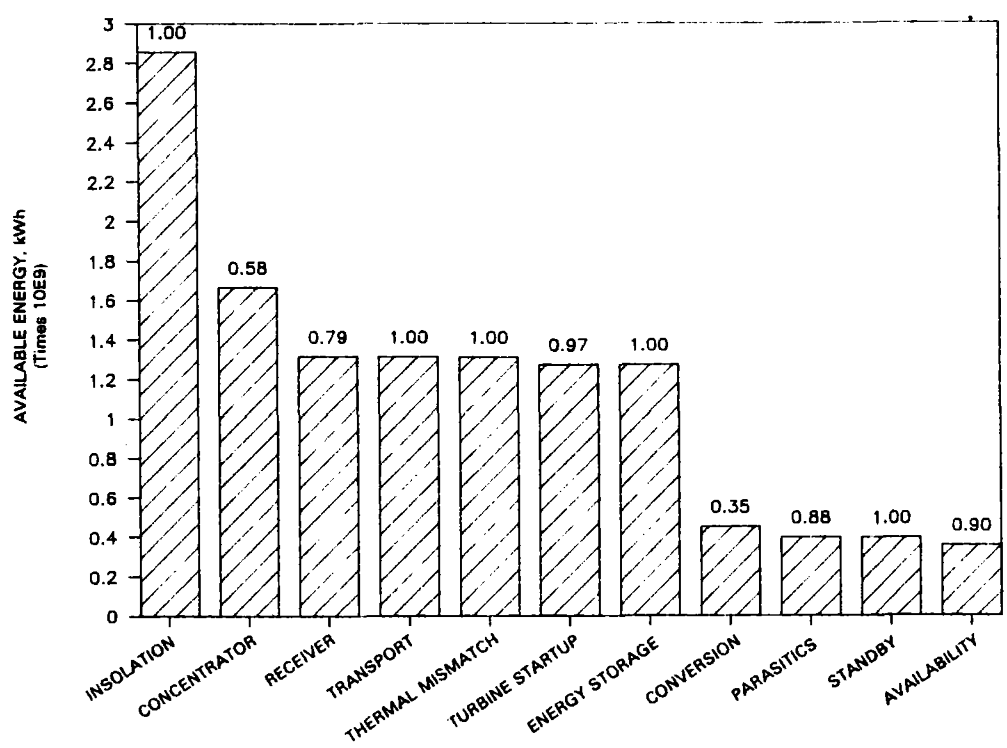

Figure C.16 Annual Energy Losses for a CR-W/S System with a 0.4 Capacity Factor in a 100 MWe Plant (977,000 m^2 field)

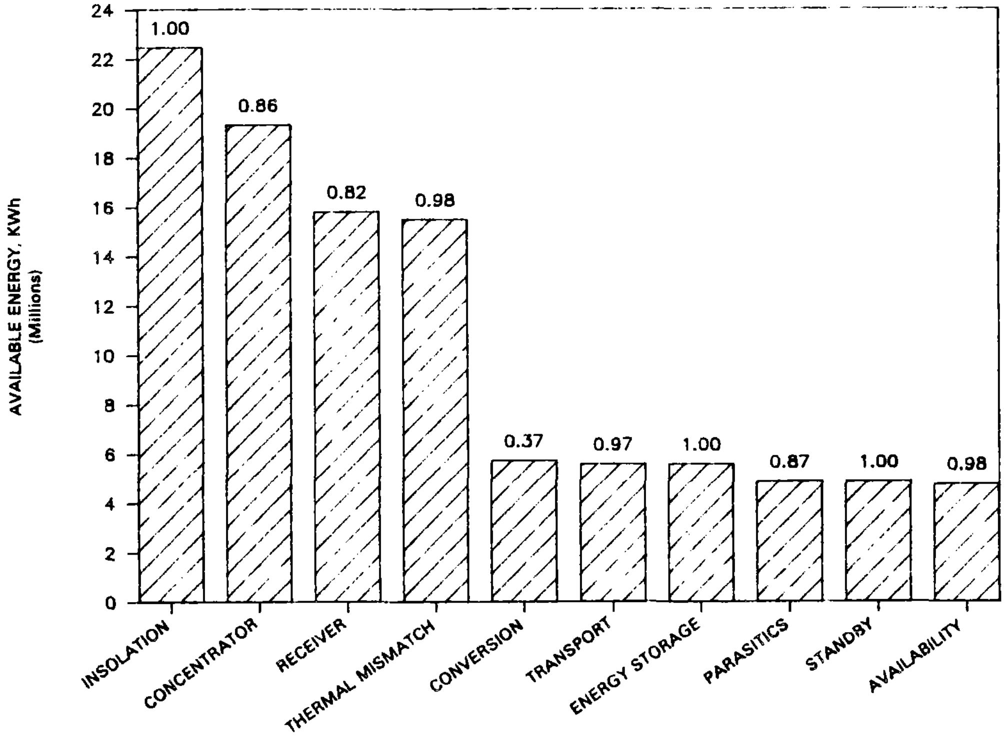

Figure C.17 Annual Energy Losses for a Dish System with a No-Storage Capacity Factor in a 2 MWe Plant (8,000 m^2 field)

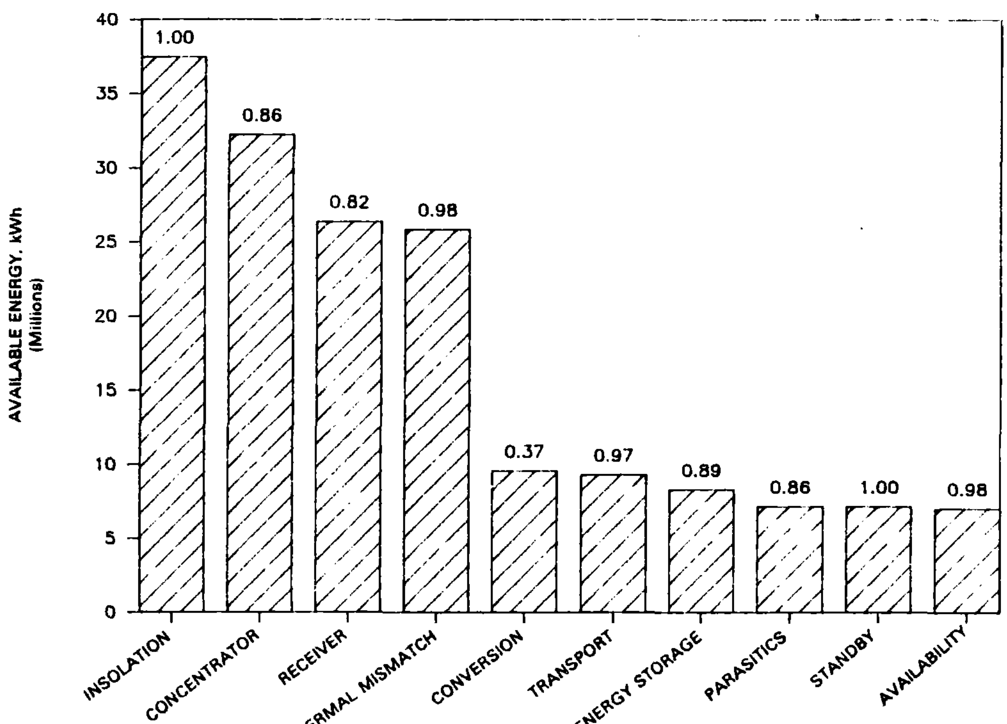

Figure C.18 Annual Energy Losses for a Dish System with a 0.4 Capacity Factor in a 2 MWe Plant (13,000 m^2 field)

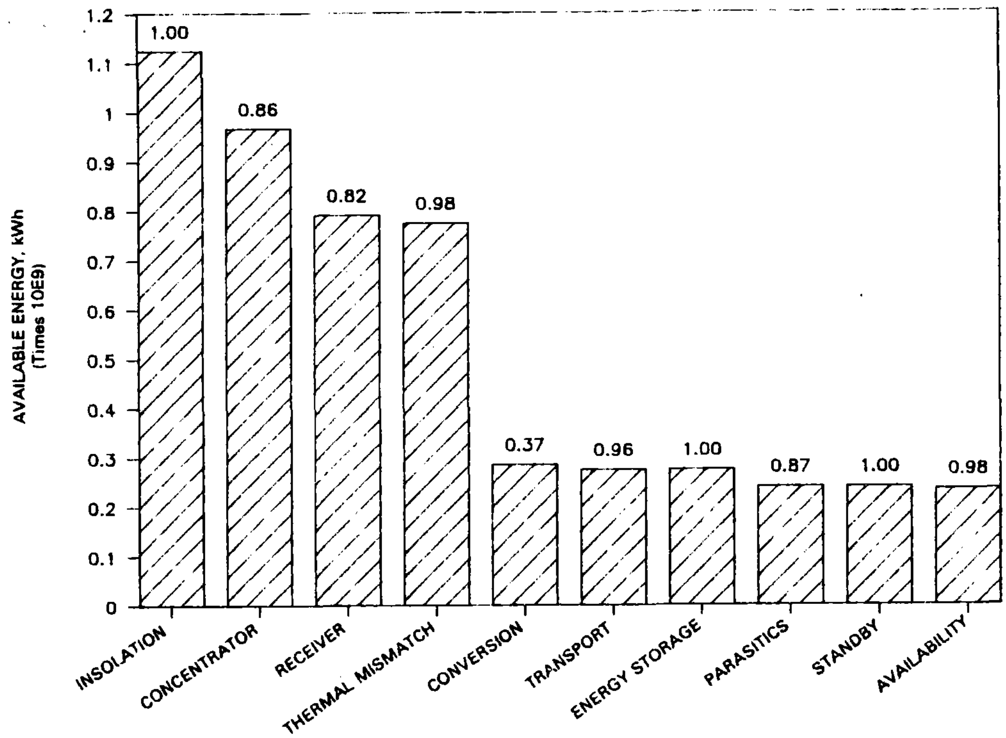

Figure C.19 Annual Energy Losses for a Dish System with a No-Storage Capacity Factor in a 100 MWe Plant (395,000 m^2 field)

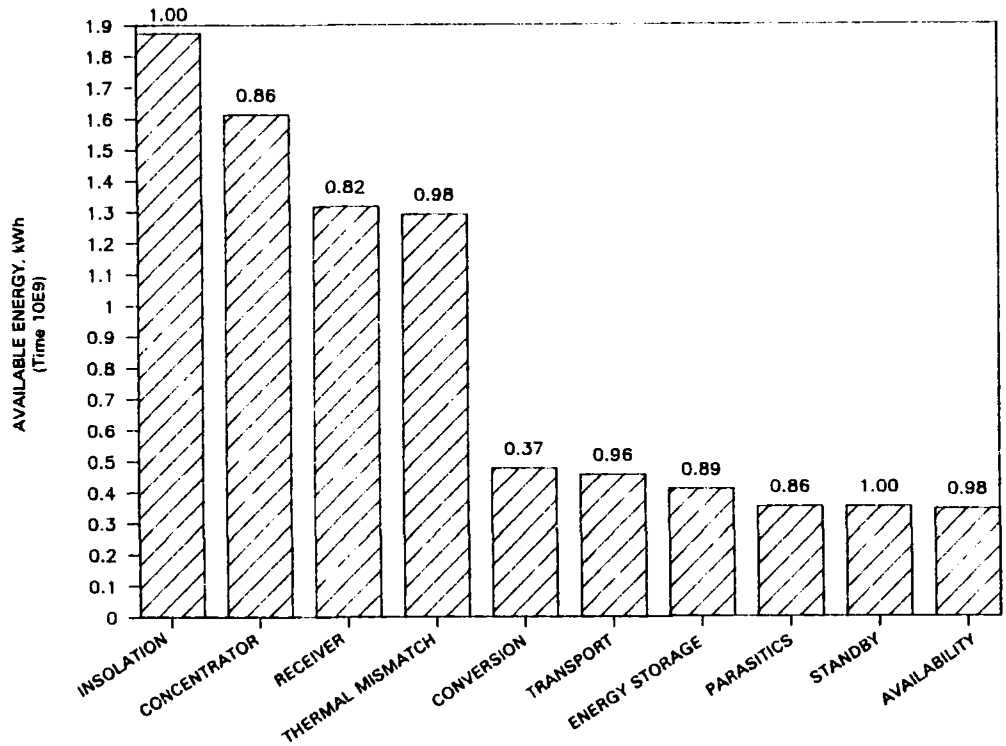

Figure C.20 Annual Energy Losses for a Dish System with a 0.4 Capacity Factor in a 100 MWe Plant (694,000 m^2 field) in a substantial drop in system efficiency. This is caused by the low round trip efficiency associated with battery storage. When compared to central receiver concepts, the dish system demonstrates better concentrator, stand-by and availability efficiency. The energy conversion efficiency of the Dish/Stirling system is below the energy conversion efficiency of most 100 MW central receiver cases, but above the 2 MW central receiver designs. The storage efficiency (when storage is required) is substantially below the central receiver storage efficiencies.C.2.6 Parabolic Trough with Oil/Rock Storage

The performance of the Trough system is summarized on Figures C.21 through C.24. The 2 MW_e concept without storage is presented in Figure C.21. The major loss mechanisms are concentrator, receiver, and conversion efficiency. The results for the 100 MW_e cases are presented in Figure C.23 and C.24. The increase in plant size has improved energy conversion efficiency, but also has a decrease in transport efficiency. The last variation is caused by the increase in the transport system size related to larger plant sizes. When compared to the molten salt central receiver designs, the trough system has substantially lower receiver, energy conversion and transport efficiency.

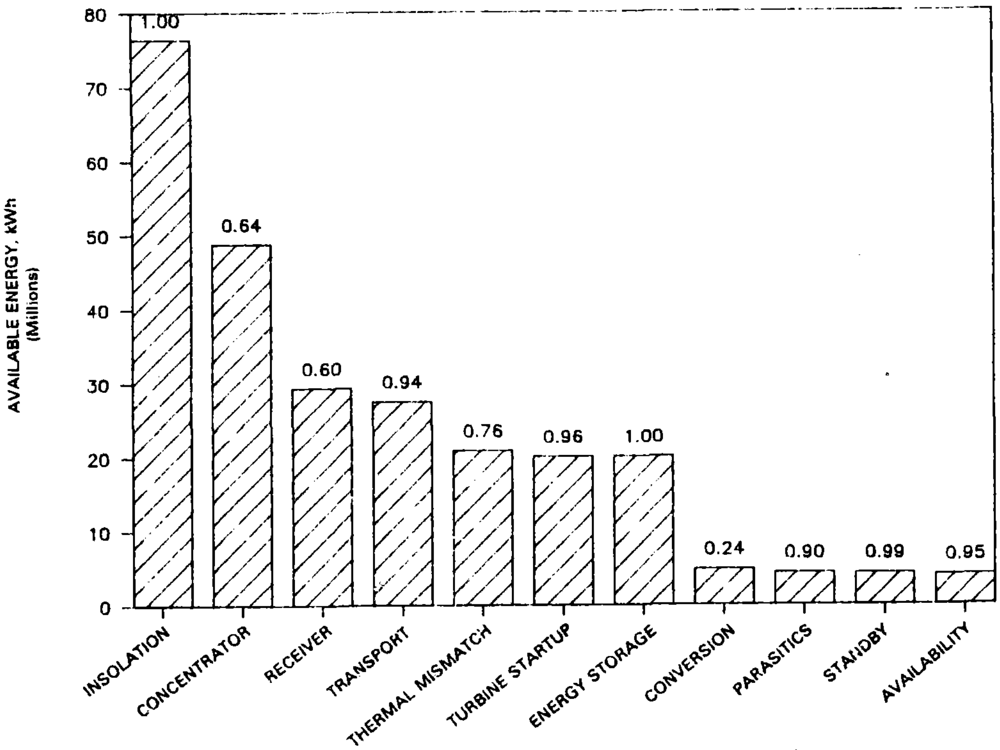

Figure C.21 Annual Energy Losses for a North-South Trough System with a No-Storage Capacity Factor in a 2 MWe Plant (27,000 m^2 field)

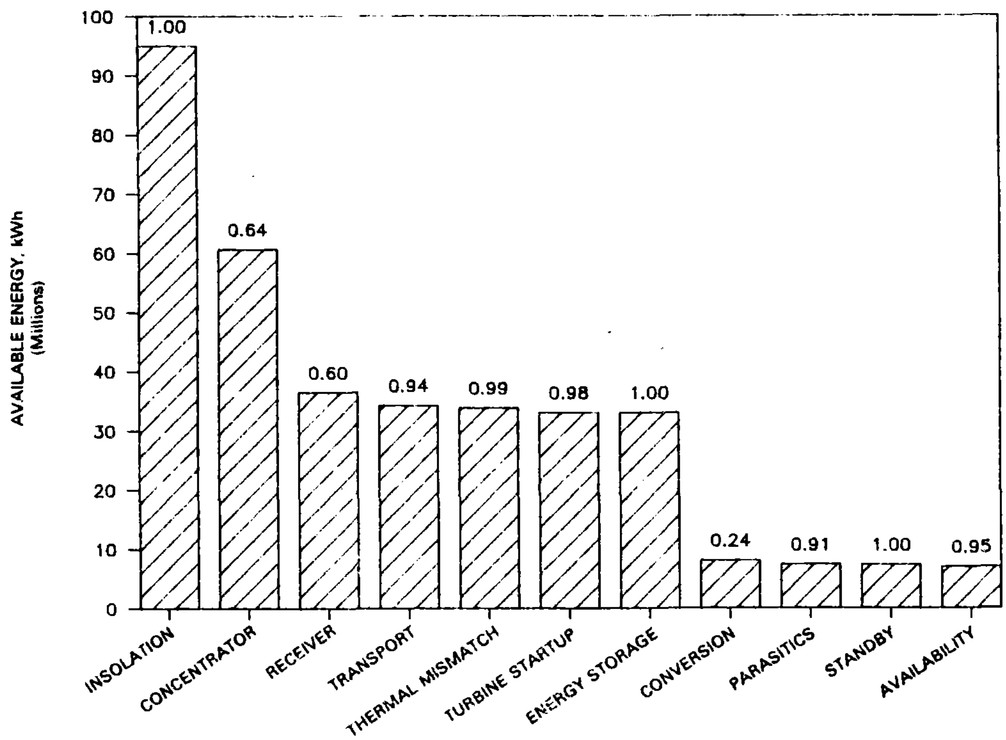

Figure C.22 Annual Energy Losses for a North-South Trough System with a 0.4 Capacity Factor in a 2 MWe Plant (34,000 m^2 field)

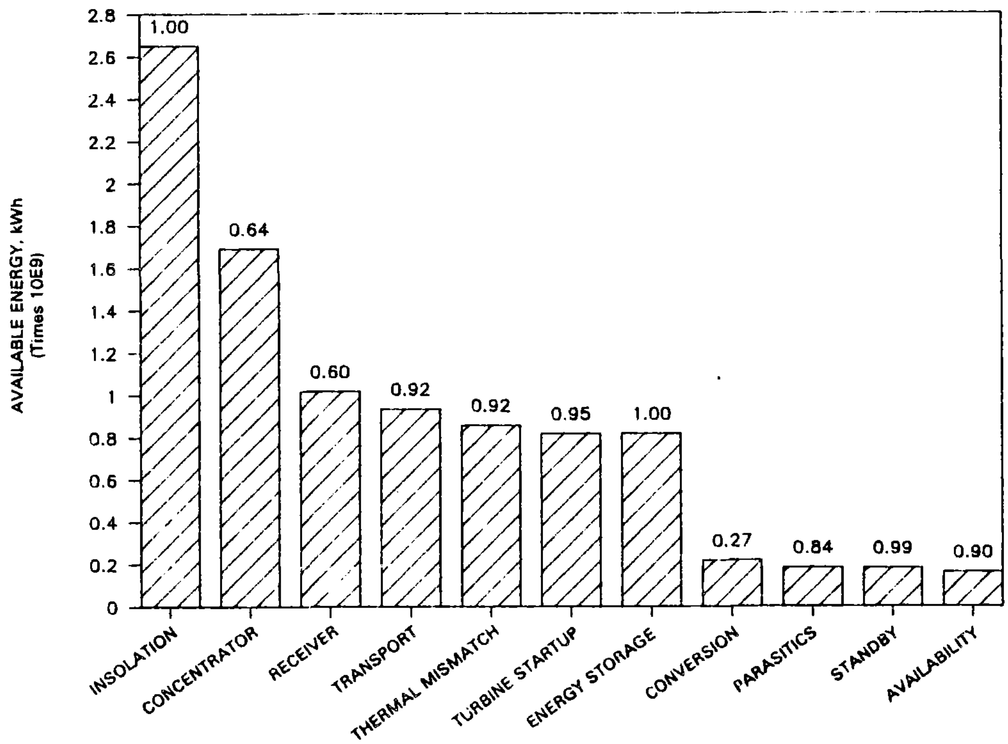

Figure C.23 Annual Energy Losses for a North-South Trough System with a No-Storage Capacity Factor in a 100 MWe Plant (930,000 m^2 field)

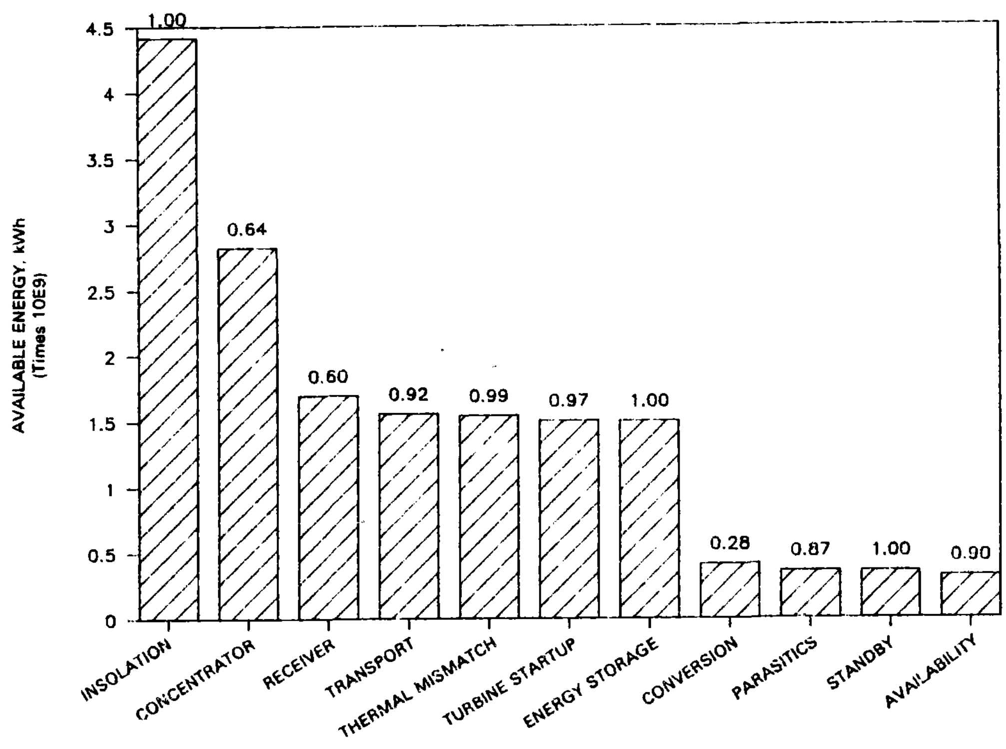

Figure C.24 Annual Energy Losses for a North-South Trough System with a 0.4 Capacity Factor in a 100 MWe Plant (1,692,000 m^2 field)

APPENDIX D

CENTRAL RECEIVER OPTICAL PERFORMANCE AND RECEIVER SIZE

APPENDIX D

CENTRAL RECEIVER OPTICAL PERFORMANCE AND RECEIVER SIZE

This appendix describes the optical performance and design parameter assumptions used in this study to generate designs for 90 central receiver systems. The designs were made using DELSOL2, a computer code developed at Sandia National Laboratories (Dellin, 1981). The optical performance, optical tower height, and receiver size for all four central receiver systems were determined by DELSOL2 and are reported in this appendix. System designs in DELSOL2 are optimized by minimizing the system levelized energy cost. For a complete understanding of the information presented in this appendix the reader will need some familiarity with the DELSOL2 code.

Following the design result, the key SOLSTEP optical inputs for the central receiver systems are explained, and the DELSOL2 estimates of annual average optical performance are presented. Finally, there is a discussion of possible improvement in performance and/or levelized energy cost of the central receiver systems in this study.

D.1 DESIGN PARAMETERS IN DELSOL2 COMMON TO ALL CENTRAL RECEIVER DESIGNS

For all of the central receiver designs in this study the design insolation was 950 W/m^2 and the design point was noon on the spring equinox. The plant was designed with the assumption that it would be located at 35° north latitude and 0.65 km above sea level (Barstow).

When possible, the DELSOL2 default inputs were used; when this was not appropriate inputs were developed from the best available information. Most of the non-default inputs are explained below.

D.1.1 Heliostat Configuration

For all of the central receiver designs in this study an ARCO type heliostat with a reflective area of 1600 square feet (148.64 square meter) was used. The outside dimensions of this heliostat are 41' 2" x 40' 6" resulting in a total area of 1667.25 square feet (154.95 square meters). The actual heliostat has one hundred 4' x 4' individual fixed focused mirror panels.

On each side of the heliostat vertical center line five of these mirror panels are connected horizontally to form a mirror module that is 4' x 20' which is able to be canted. Since DELSOL2 cannot exactly model this heliostat design it was assumed that each of the 20 canting mirror modules actually consisted of one focused mirror panel.

D.1.2.1 Canting and Focusing Assumptions

Canting is a discrete approximation of focusing; thus, like focusing, it reduces the reflected beam size from the heliostat. This results in the optimal receiver or aperture being smaller and hence more efficient. The mirror modules on the heliostats were all canted using symmetrical "on-axis" canting, (on-axis means canting is set for each heliostat assuming that the sun, receiver, and heliostat are all in a straight line). Thus, when the sun is in another position there will be off-axis aberrations. However, on-axis canting will result in the minimum off-axis aberrations on a annual basis. Again, the actual heliostat has 100 individual panels that have a fixed focal length but the canting is only possible for the 20' x 4' modules. DELSOL requires the modules to be described the same for canting and focusing. By assuming that the modules (and mirror panels) are 20' x 4', all actual mirror area centers are accurately described in the input to DELSOL2; this minimizes the possible errors since the effect of heliostat mirror module canting dominates the effect of mirror panel focusing.

The canting of heliostats is done during the heliostat field assembly. Thus, canting at the slant range or selecting several different cant focal lengths for the field should not significantly effect the installed cost of the heliostat field. The canting scheme assumed in the Saguaro design was done by dividing the field into 10 zones (Weber, 1983). Since this is not possible in DELSOL2 it was assumed that the cant focal length was equal to the slant range of each individual heliostat.

Focusing each individual mirror module on a heliostat would be extremely expensive and offers little improvement in performance. Some heliostat designs (e.g., The Martin Marietta design at the CRTF) allow for the focal length of the mirror panel to be changed after the heliostat has been installed. This would be extremely costly and time consuming for large fields. For most other heliostats, the focal length is fixed at the factory. Focusing at the slant range for this type of heliostat would require different focal lengths of the mirror panels for every different row in the heliostat field. The fabrication cost, and cost for spare parts could be very large. In either case it was felt that the additional cost of focusing the mirror modules at the slant range was not justified. Thus, a single focal length of the mirror modules was selected. Due to the finite size of the sun, the most distant heliostat will have the largest reflected beam size. Thus, the focal length for module focusing that will minimize the annual spillage is the focal length of the most distant heliostat. Therefore, it was assumed that the mirror modules would be factory focused in two directions at a focal length equal to RADMAX (8.8 tower heights).

D.1.2.2 Heliostat Cleaning and Average Reflectivity

Heliostat cleaning and the assumed average annual reflectivity of the heliostat are very important design parameters. For each one percent degradation in the annual average reflectivity the output energy of the plant will be reduced by a greater percentage. This is because some losses are relatively fixed in absolute terms, such as receiver losses and plant parasitics. Decreased reflectivity will also cause operational changes, like delayed start-up, earlier shut-down, and non-operation during times of marginal insolation. In discussing heliostat cleaning with experts at Sandia[a], it was noted that:

1. The heliostat wash-truck at Barstow is not working as well as it could (currently cleaning is not bringing reflectivity up to 99% of clean). This is due to the fact that the brushes do not always go all the way to the edge of the mirror modules. With adjustment it is expected that cleaning should bring the reflectivity up to 99% of clean.
2. Heliostat washing will be more effective when laminated glass modules (like ARCO's) are used instead of modules like at Barstow with a metal edge rim.

(a) Clay Mavis, Sandia National Laboratory, personal communication to J. A. Dirks (September 16, 1985).

3. Washing every 2 weeks at Barstow should result in average reflectivity of 97% of clean (assuming cleaning only brings reflectivity up to 99% of clean).

The out-of-box reflectivity of the heliostat used in this study is assumed to be 94%. An average annual reflectivity of 92% (including degradation) was used for the heliostat fields. This could be accomplished by cleaning semi-monthly with an efficiency that will bring the heliostats up to 99.6% of clean if the heliostat soiling rate is the same as Barstow's. The Saguaro design assumed that bimonthly cleaning could maintain an annual average reflectivity of 92%; but again, this is dependent on the soiling rate. One thing is clear however, the cost of occasional cleaning is far exceeded by the value of increased energy output. The optimal amount of cleaning will depend on the soiling rate at a particular site and the value of the additional energy that can be produced.

D.1.2 Tower Height and Field Layout

In DELSOL2 the heliostats are laid out in radial stagger pattern with the user specifying how near the closest heliostat (RADMIN) and how far the furthest heliostat (RADMAX) are located from the tower. These values are normalized to the tower height. The tower height given by DELSOL2 (THT) is the optical tower height and is defined as the elevation of the middle of the cavity aperture, or external receiver, above the pivot point of the heliostat. The heliostat pivot point for the 1600 square feet heliostat used in this study is 6.5 meters above ground level.

The tower height cost algorithm in DELSOL2 is thought to under estimate the actual cost of constructing a tower, especially for taller towers (this is one of the differences between DELSOL2 and the revised, but currently unreleased DELSOL3). Thus, as long as the performance and levelized energy cost of a system is only negligibly affected by the DELSOL2 predicted tower height and cost, shorter towers are preferred to taller towers, since the effect on the levelized energy cost of underestimating the tower cost would be smaller for shorter towers.

For a specific power level, the optimal tower height for a north field design can be more that 40% greater than the optimal surround field tower height. Since tower cost increases faster than tower height, the molten nitrate salt cavity designs (north fields) in this study would be affected the most by the assumptions that influence tower height. The cavity systems in this study were based on the Saguaro design, which has a RADMIN of approximately .75 and a RADMAX of 8.8 (Weber, 1983). The DELSOL2 defaults for RADMIN and RADMAX are .75 and 7.5. Optimized systems were design for the Saguaro receiver design point (190 MW_t) using both the Saguaro design parameters and the DELSOL2 defaults. The resulting DELSOL2 estimates of levelized energy costs showed that using a RADMAX of 8.8 produced a slightly lower (0.5%) levelized energy cost than the DELSOL2 default (RADMAX = 7.5), and a significantly shorter tower (6.9%).

For the external receivers with surround fields, designs were done with both a RADMAX of 7.5 and 8.8, at a power rating of 190 MW_t. The DELSOL2 estimate of the levelized energy cost for the sodium receiver system was 0.3% less using a RADMAX of 8.8 instead of the default (7.5), and the water/steam system levelized energy cost was unchanged. However, in both cases the tower heights were much shorter; for the sodium case 6.6%, and for the water/steam case 8.5%. While these differences may not seem significant, if the tower height cost algorithm is grossly underestimates the actual cost, the effect could be much more pronounced.

D.1.3 Economic and Cost Assumptions

Five Year Plan (DOE, 1984) economics were used for a inputs pertaining to discount rates, inflation, fixed charge rates, and allowance for funds used during construction. (See Appendix B for a detailed description of the economics inputs and levelized energy cost calculations). In addition, operating and maintenance costs were assumed to be 1.66% of the installed capital cost; this is consistent with the Five Year Plan for a 100 MW_e plant with a 50% capacity factor.

The cost inputs used in this analysis were the DELSOL2 defaults with two exceptions:

1) For cavity receiver designs the parameter ARECRF was adjusted. This was done because DELSOL2 grossly overestimates the absorber area for cavity receivers. The absorber height calculated by DELSOL2 is done by assuming the ray from the heliostat at minimum radius from the tower goes through the top of the aperture and strikes the top of the absorber surface. While the ray from the heliostat at the maximum radius for the tower goes through the bottom of the aperture and strikes the bottom of the absorber surface. The cavity angle is calculated in a similar fashion. This is clearly a worse case scenario. The actual Saguaro design absorber area was 776.55 square meters while the DELSOL2 absorber area calculated for this design was 1750.24. To account for this fact, the reference receiver area in the inputs was adjusted so that the code, given the Saguaro receiver dimensions, would give a cost for an absorber area the size of Saguaro's even though it calculated a larger area. Thus, these optimized designs do not assume abnormally high receiver costs (due to the absorber area calculation) which would tend to make the receiver smaller at the cost of increased spillage.

2) Instead of using $7,000,000 for the fixed costs (the default) as was done for the 10-100 MW_e cases, fixed costs of $500,000 were used for the 0.5 and 2 MW_e. This is more in line with a small power producer and not a standard utility power plant. If the larger fixed cost had been used for the smaller plants, they would have been designed for maximum efficiency (annual output) almost without respect to cost of the solar portion of the plant.

D.2 TECHNOLOGY SPECIFIC ASSUMPTIONS

With three different receiver designs and working fluids, different design assumptions were required for each system.

D.2.1 Design Flux Limits

The design incident flux limits of a receiver depends on the working fluid, tube material, tube wall thickness, receiver geometry, and receiver losses. The molten salt cavity receiver had a design incident flux of 0.6 MW_t/m^2; this is a typical value for this type of receiver. The design incident flux of the Solar 100 (SCE, 1982) was 0.6 MW_t/m^2 and the Saguaro (Weber, 1982) receiver was 5.8 MW_t/m^2. The sodium external receiver had the highest design incident flux (1.2 MW_t/m^2) due to the excellent heat transfer characteristics of the working fluid. This is the same design peak incident flux as used in the Carrisa Plains design (Rockwell, 1983). Lastly, the water/steam central receiver peak incident flux was limited to 0.6 MW_t/m^2; additionally, the water/steam designs were constrained to have an average incident flux of 0.225 MW_t/m^2.

The design flux will be exceeded during the receiver life so it is not intended to be an actual limit. The design flux can be exceeded for several reasons:

1) The actual insolation at the Saguaro site and at Barstow goes 10% or more above the design point insolation (950 W/m^2).

2) Maximum field performance does not always occur on the design day (spring equinox). Thus, at any time that the insolation equals or exceeds the design point insolation (950 W/m^2), and the field performance is greater than that of the design point, there will be the potential for peak incident fluxes greater than the design limit.

3) The peak flux does not always occur at solar noon. Hours just before or after noon can have larger receiver peak fluxes than at noon using the DELSOL2 aim point strategies.

Many of these problems can be mitigated with a good heliostat aim point strategy. DELSOL2 does have aim point strategies which help to spread the flux across the absorber but they are not optimal (See Section D.2.2). In any case, the design flux limits specified above are conservative, and any peak fluxes that exceed the design flux should easily be handled by the receivers.

D.2.2 Receiver Optical Performance Calculation and Aim Points

The receiver optical performance is its effective absorption. Based on the receiver tube material, absorber coating, and the geometry of the receiver cavity, the optical efficiency of all cavity receiver designs was estimated to be 0.98. This value is consistent with the average annual receiver reflectivity of the Saguaro receiver (Weber, 1983). External receiver designs do not benefit from the cavity effects and have correspondingly lower optical efficiency. All external receiver designs have an estimated annual average absorption of 0.96. While this value is somewhat lower than the 0.97 that has been consistently measured at Barstow, it should be able to be maintained on an annual basis with periodic receiver painting.

Since all the central receiver designs done in this study were flux limited, "smart" aiming strategies available in DELSOL2 were used to limit the peak fluxes while minimizing the spillage.

D.2.2.1 Aim Points for Cavity Receivers

All cavity designs were done using the DELSOL2 aim point strategy IAUTOP=2. This is a two-dimensional "smart" aiming strategy which spreads the flux across the aperture in both the vertical and horizontal direction. This results in the smallest maximum peak flux at any point on the absorber surface for the available DELSOL2 aim point strategies. It also decreases the ratio of the peak to average flux (i.e., decreases the flux gradients across the receiver). Use of this aim point strategy results in an insignificant increase in spillage while significantly reducing the receiver size.

The IAUTOP=2 aim point strategy was also used in the performance calculations for the 100 and 30 MW_e designs. However, one of the DELSOL2 code writers suggested that the performance calculations for the smaller systems (0.5, 2.0, and 10.0 MW_e) would be more accurate if they were done using the DELSOL2 parameter INDC=1[a]. This considers each mirror module on a heliostat separately and results in a more accurate image from each heliostat. The only draw-back is that the aim point strategy that must be employed with INDC=1 is IAUTOP=0, which aims every heliostat at the center of the aperture. While

(a) John, M. E. 1985. Personal communication.

the design was done with one aim point strategy and the performance with another there was not a problem with consistency or with exceeding the peak flux limit since neither aim point strategy is optimal. An optimal aim point strategy should be able to keep the peak flux below the design point and minimize spillage at the same time. In the Saguaro design it was found that:

> If selected groups of heliostats are aimed slightly off-center, peak fluxes on the receiver panels can be reduced by as much as 40% without increasing receiver size. The aiming strategy also smooths out the flux distribution, thereby simplifying control and extending the useful life of the receiver without increasing spillage (Weber, 1983).

D.2.2.2 Aim Points for External Receivers

All external receiver designs were done using the DELSOL2 aim point strategy IAUTOP=1. This is a one-dimensional "smart" aiming strategy which spreads the flux across the aperture in only the vertical direction. The effect is a reduction in the maximum peak flux at any point on the absorber surface and also a reduction in the ratio of the peak to average flux. As with the two-dimensional aim point strategy employed with the cavity receivers, the one-dimensional strategy results in an insignificant increase in spillage while significantly reducing the receiver size. The IAUTOP=2 aim point strategy could not be used for the cylindrical receivers because it spreads the flux in the horizontal direction as much as possible without significantly increasing the spillage. This would result in some the flux striking the receiver at large incident angles which would reduce the absorption.

A compromise between IAUTOP=1 and IAUTOP=2 would help to reduce the peak flux without significantly decreasing the receiver absorption. If such a strategy existed in DELSOL2 the sodium external receiver designs would be smaller and more efficient; but, they still would not have peak fluxes above the limit. The water/steam receiver designs would not benefit from the improved aim point strategy because those designs were constrained to have an average incident flux of 0.225 MW_t/m^2. However, the operating lifetime of all receivers could be improved by aim point strategies which reduce the peak flux and the flux gradients.

To maintain consistency with the analysis done for the cavity designs the IAUTOP=1 aim point strategy was used in the performance analysis of the 100 and 30 MW_e designs, and for the 0.5, 2.0, and 10.0 MW_e designs INDC=1 and IAUTOP=0 were used.

D.3 DELSOL2 DESIGN RESULTS

Significant design results for the molten salt cavity receivers from DELSOL2 are shown in Table D.1. At each power level, six different designs were produced for solar multiples 1.0 through 2.8. The optical tower height (vertical distance from the heliostat pivot point to the center of the cavity aperture) for each design is presented below. This is somewhat shorter than would result if the DELSOL2 defaults were used (see Section D.1.2). Another interesting result of using a RADMAX of 8.8 is that the peak performance of the field occurs closer to winter solstice than it would if the default value of RADMAX (7.5) had been used. In addition, the use of a larger value of RADMAX provides a more level daily output than does the default value. Cavity receiver design information is also presented in Table D.1. All cavity apertures are square in this analysis and the height and width dimensions are given in the table. Additionally, the cavity depth is given; this is the horizontal distance from the aperture to the center of the absorber surface.

The sixth and seventh columns show the number of heliostats and the design point power for each design. Finally, the design average aperture flux in given; this is simply the incident power entering the aperture at the design point divided by the aperture area. This is not the average incident absorber flux. The average incident absorber flux in considerably less than the aperture flux. This is because the flux beam is most concentrated at the aperture and then diverges before striking the much larger aperture area. Design results for the sodium and water/steam external receivers from DELSOL2 are shown in Tables D.2 and D.3. The optical tower height and receiver dimensions are listed in columns 3 through 5. The sixth and seventh columns show the number of heliostats and the design point power for each design.

TABLE D.1. DELSOL2 Design Results for Molten Salt Cavity Receivers with North Fields

Power Level (MW_e)	Solar Multiple	Optical Tower Height (m)	Aperture Width & Height (m)	Cavity Depth (m)	Number of Heliostats	Design Power (MW_t)	Design Ave. Aperture Flux (MWt/m2)
0.5	1.0	23.0	2.80	1.40	33	2.640	0.337
	1.2	25.0	2.90	1.80	38	3.114	0.370
	1.6	26.0	3.40	1.90	47	4.136	0.358
	2.0	29.0	3.60	2.40	55	5.041	0.389
	2.4	30.0	3.70	2.35	67	6.010	0.439
	2.8	32.0	4.10	2.65	73	7.010	0.417
2.0	1.0	33.0	4.80	2.50	85	8.492	0.369
	1.2	34.5	5.00	2.65	102	10.076	0.403
	1.6	40.0	5.40	3.35	128	13.210	0.453
	2.0	44.0	5.70	4.00	157	16.299	0.502
	2.4	46.0	6.30	4.00	187	19.542	0.492
	2.8	50.0	7.10	4.20	213	22.904	0.454
10.0	1.0	63.0	6.60	6.80	347	35.414	0.813
	1.2	67.0	8.40	6.40	403	43.026	0.610
	1.6	75.0	9.50	7.00	545	57.123	0.633
	2.0	85.0	10.50	8.00	666	71.133	0.645
	2.4	90.0	11.50	8.10	819	85.233	0.644
	2.8	100.0	11.00	10.29	938	97.781	0.808
30.0	1.0	95.0	11.50	8.80	889	92.599	0.700
	1.2	105.0	12.50	10.10	1054	110.84	0.709
	1.6	120.0	14.20	11.50	1413	147.19	0.730
	2.0	135.0	16.00	12.60	1759	184.00	0.719
	2.4	147.0	16.90	14.20	2121	219.61	0.769
	2.8	155.0	18.60	14.00	2516	256.83	0.742
100.0	1.0	160.0	19.50	14.00	2751	278.64	0.733
	1.2	182.0	20.40	17.60	3238	332.01	0.798
	1.6	205.0	25.00	17.60	4404	446.21	0.714
	2.0	230.0	27.00	20.70	5550	554.93	0.761
	2.4	260.0	29.00	24.00	6631	664.07	0.790
	2.8	280.0	32.00	25.00	7809	776.89	0.759

TABLE D.2. DELSOL2 Design Results for Sodium External Receivers with Surround Fields

Power Level (MW_e)	Solar Multiple	Optical Tower Height (m)	Aperture Width & Height (m)	Cavity Depth (m)	Number of Heliostats	Design Power (MW_t)	Design Ave. Aperture Flux (MWt/m2)
0.5	1.0	21.0	2.60	2.14	37	2.888	0.165
	1.2	21.5	2.90	2.25	41	3.387	0.166
	1.6	23.5	3.15	2.36	51	4.411	0.189
	2.0	25.5	3.40	2.55	60	5.386	0.198
	2.4	27.0	3.55	2.66	69	6.360	0.214
	2.8	28.5	3.70	2.78	78	7.333	0.277
2.0	1.0	28.0	3.90	2.83	94	8.701	0.251
	1.2	31.0	4.20	3.04	107	10.350	0.259
	1.6	34.0	4.50	3.26	139	13.567	0.295
	2.0	37.0	4.80	3.60	167	16.759	0.309
	2.4	40.0	4.90	3.80	198	19.886	0.340
	2.8	42.0	5.10	4.21	227	23.017	0.341
10.0	1.0	42.0	5.55	4.99	404	35.669	0.410
	1.2	47.0	5.90	5.31	461	42.889	0.436
	1.6	54.0	6.65	6.32	589	56.868	0.431
	2.0	59.0	6.95	7.12	736	70.561	0.454
	2.4	65.0	7.70	7.70	869	84.445	0.453
	2.8	70.0	8.05	8.45	1009	98.264	0.460
30.0	1.0	66.0	7.45	8.19	971	92.004	0.480
	1.2	71.0	8.60	8.17	1171	110.01	0.498
	1.6	83.5	9.40	10.34	1529	146.58	0.481
	2.0	93.5	10.95	10.95	1903	182.89	0.486
	2.4	103.5	11.50	12.65	2270	219.44	0.479
	2.8	113.5	12.55	13.81	2636	256.04	0.470
100.0	1.0	110.0	12.75	12.75	2995	275.79	0.540
	1.2	127.5	14.00	15.40	3471	332.18	0.490
	1.6	150.0	16.00	18.40	4614	443.16	0.479
	2.0	177.5	19.13	21.05	5688	557.15	0.440
	2.4	187.5	19.82	22.79	6967	665.12	0.469
	2.8	220.0	21.25	26.56	7972	779.59	0.440

Finally, the design incident flux in given; this is simply the design point incident power striking the absorber surface divided by the absorber area. Note that in Table D.3, the design average incident flux is very close to 0.225 MW_t/m^2, except at the smallest plant designs where the receiver design is driven by the spillage. This was a design constraint for the water/steam receivers.

TABLE D.3. DELSOL2 Design Results for Water/Steam External Receivers with Surround Fields

Power Level (MW_e)	Solar Multiple	Tower Height (m)	Optical Width & Height (m)	Aperture Cavity Depth (m)	Number of Heliostats	Design Power (MW_t)	Design Ave. Aperture Flux (MWt/m2)
0.5	1.0	22.0	2.55	1.98	42	3.090	0.195
	1.2	23.0	2.70	2.09	47	3.613	0.203
	1.6	24.0	2.95	2.29	57	4.609	0.218
	2.0	23.5	3.40	2.38	68	5.646	0.222
	2.4	23.5	3.75	2.53	80	6.621	0.222
	2.8	23.5	3.90	2.73	94	7.472	0.223
2.0	1.0	24.0	4.40	2.86	113	8.780	0.222
	1.2	25.5	5.00	3.00	129	10.550	0.222
	1.6	28.0	6.10	3.20	168	13.935	0.224
	2.0	30.0	6.55	3.77	204	17.400	0.227
	2.4	32.5	4.95	5.94	233	20.785	0.225
	2.8	34.5	5.15	6.69	269	24.176	0.223
10.0	1.0	43.0	5.25	10.50	431	38.778	0.224
	1.2	47.0	5.75	11.64	504	46.636	0.222
	1.6	53.0	6.25	13.91	671	61.824	0.226
	2.0	59.0	7.00	15.75	827	77.353	0.223
	2.4	64.0	7.25	17.94	998	92.537	0.226
	2.8	69.0	8.25	18.77	1152	108.15	0.222
30.0	1.0	67.0	7.75	18.41	1082	101.23	0.226
	1.2	74.0	8.50	19.97	1278	121.27	0.227
	1.6	84.0	9.50	23.99	1731	161.72	0.226
	2.0	93.0	10.60	26.76	2180	201.94	0.227
	2.4	103.0	11.40	29.92	2596	242.31	0.226
	2.8	112.0	12.60	31.81	3018	282.84	0.225
100.0	1.0	114.0	12.95	33.67	3341	306.69	0.224
	1.2	130.0	13.55	38.62	3910	368.01	0.224
	1.6	146.0	16.55	41.79	5333	489.87	0.225
	2.0	162.0	18.50	46.25	6745	611.51	0.227
	2.4	184.0	20.55	50.35	7940	734.38	0.226
	2.8	196.0	21.70	55.33	9418	856.29	0.227

D.4 SOLSTEP INPUTS AND DELSOL2 OPTICAL PERFORMANCE RESULTS

The optical performance of the DELSOL2 optimized fields are transferred to the SOLSTEP code by means of a matrix of field performance data. This matrix gives the field performance for 117 sun locations based on the sun azimuthal and zenith angles. The matrix bounds the possible sun positions for a solar plant located at a latitude of 35° (Barstow). The DELSOL2 output includes the average heliostat reflectivity (.92) and the receiver absorptivity (.98 or .96). Thus, to be input to SOLSTEP the values in the column marked total must be divided by the production of these two values. In addition, SOLSTEP accepts concentrator performance input matrix (GOE) only in the form of azimuth and altitude (elevation) angles. Thus, the zenith angle outputs from DELSOL2 must be converted to altitude angles. Table D.4 describes the key optical inputs to SOLSTEP.

TABLE D.4. Description of Key Optical Inputs to SOLSTEP (For All Designs)

GOE	= Array of geometric optics data (includes cosine, shadowing, blocking, atmospheric transmission, and spillage)
NALT	= 9 - number of altitude angles in GOE (Maximum from DELSOL2)
ALTDAT	= 10, 20, 30, 40, 50, 60, 70, 80, 85 (angles measured from vertical) The maximum ALT for Barstow occurs on summer solstice and is 11.56. The minimum given is 85 (5 degrees above the horizon); the spacing at low sun angles was made smaller to give more accurate results during start-up and shutdown
NAZM	= 13 - number of azimuth angles in GOE
AZMDAT	= 0, 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 110, 120 (angles measured from the south, 90 being due east or west) The maximum AZM for Barstow occurs on summer solstice as the sum clears the horizon and is 118.98. The minimum given is 0 and occurs every day at solar noon.
XLAT	= 35° (latitude of Barstow)
OPTEFC	= .94 (ARCO clean reflectivity)
DEGFAC	= .92/.94 (average reflectivity is 92%)
COLREC	= 1 - concentrator/receiver intercept (spillage is included in GOE)
ATMOS	= 1 - atmospheric transmission (included in GOE)
ABSORB	= .98 (cavity receiver absorption) or .96 (external receiver absorption)

In Tables D.5 through D.7 the DELSOL2 results for annual average performance are given for each design. These results are somewhat different than would be predicted by SOLSTEP because DELSOL2 does not use actual insolation data and it predicts annual performance based on only a few days of detailed performance data. Listed in columns 3 through 7 are the DELSOL2 estimations of annual cosine, shadowing, blocking, atmospheric transmission, and spillage losses. The final column labeled total includes the receiver absorptivity (0.98 for cavity receivers and 0.96 for external receivers) and the annual average heliostat reflectivity (0.92 for all concepts).

TABLE D.5. DELSOL2 Annual Performance Results for Molten Salt Cavity Receivers with North Fields

Power Level (MW_e)	Solar Multiple	Cosine	Shadowing	Blocking	Atmos. Trans.	Spillage	Total
0.5	1.0	0.832	0.967	0.907	0.981	0.685	0.442
	1.2	0.832	0.968	0.910	0.979	0.706	0.456
	1.6	0.829	0.965	0.920	0.979	0.761	0.495
	2.0	0.833	0.964	0.927	0.978	0.795	0.522
	2.4	0.828	0.964	0.933	0.977	0.776	0.509
	2.8	0.831	0.963	0.939	0.976	0.830	0.548
2.0	1.0	0.826	0.964	0.938	0.976	0.875	0.574
	1.2	0.823	0.961	0.945	0.975	0.861	0.566
	1.6	0.826	0.962	0.955	0.972	0.893	0.594
	2.0	0.828	0.959	0.959	0.971	0.898	0.599
	2.4	0.825	0.958	0.960	0.970	0.907	0.601
	2.8	0.828	0.956	0.963	0.968	0.937	0.623
10.0	1.0	0.827	0.955	0.976	0.962	0.883	0.591
	1.2	0.826	0.956	0.978	0.960	0.938	0.626
	1.6	0.823	0.954	0.982	0.956	0.928	0.617
	2.0	0.826	0.955	0.985	0.952	0.951	0.634
	2.4	0.822	0.953	0.986	0.950	0.934	0.618
	2.8	0.826	0.954	0.988	0.946	0.934	0.620
30.0	1.0	0.823	0.953	0.988	0.948	0.934	0.619
	1.2	0.825	0.953	0.990	0.944	0.946	0.627
	1.6	0.825	0.951	0.991	0.938	0.945	0.622
	2.0	0.827	0.951	0.993	0.932	0.955	0.626
	2.4	0.826	0.950	0.993	0.928	0.950	0.620
	2.8	0.822	0.950	0.993	0.924	0.946	0.611
100.0	1.0	0.820	0.952	0.994	0.922	0.943	0.608
	1.2	0.827	0.949	0.994	0.915	0.955	0.615
	1.6	0.823	0.950	0.994	0.905	0.958	0.608
	2.0	0.823	0.950	0.994	0.897	0.955	0.600
	2.4	0.827	0.948	0.995	0.889	0.961	0.601
	2.8	0.827	0.948	0.995	0.881	0.964	0.597

TABLE D.6. DELSOL2 Annual Performance Results for Sodium External Receivers with Surround Fields

Power Level (MW_e)	Solar Multiple	Cosine	Shadowing	Blocking	Atmos. Trans.	Spillage	Total
0.5	1.0	0.817	0.967	0.895	0.982	0.660	0.404
	1.2	0.815	0.965	0.903	0.982	0.701	0.432
	1.6	0.816	0.963	0.909	0.981	0.729	0.451
	2.0	0.818	0.962	0.917	0.980	0.764	0.477
	2.4	0.816	0.961	0.922	0.979	0.777	0.486
	2.8	0.816	0.960	0.930	0.979	0.791	0.498
2.0	1.0	0.798	0.959	0.935	0.979	0.794	0.492
	1.2	0.806	0.957	0.939	0.978	0.827	0.518
	1.6	0.802	0.955	0.946	0.977	0.841	0.526
	2.0	0.803	0.954	0.952	0.976	0.865	0.543
	2.4	0.802	0.953	0.957	0.975	0.870	0.548
	2.8	0.799	0.953	0.962	0.974	0.890	0.561
10.0	1.0	0.736	0.960	0.964	0.972	0.896	0.523
	1.2	0.749	0.957	0.968	0.971	0.916	0.545
	1.6	0.755	0.955	0.972	0.968	0.948	0.568
	2.0	0.750	0.956	0.976	0.965	0.957	0.571
	2.4	0.754	0.955	0.979	0.963	0.968	0.581
	2.8	0.755	0.955	0.981	0.961	0.973	0.584
30.0	1.0	0.744	0.957	0.981	0.962	0.965	0.573
	1.2	0.740	0.957	0.983	0.959	0.970	0.572
	1.6	0.749	0.955	0.985	0.955	0.982	0.583
	2.0	0.751	0.955	0.987	0.951	0.985	0.586
	2.4	0.756	0.954	0.989	0.947	0.987	0.588
	2.8	0.760	0.953	0.990	0.944	0.988	0.590
100.0	1.0	0.736	0.957	0.992	0.941	0.984	0.571
	1.2	0.756	0.953	0.992	0.938	0.989	0.585
	1.6	0.762	0.952	0.993	0.930	0.989	0.585
	2.0	0.776	0.949	0.993	0.922	0.990	0.590
	2.4	0.766	0.951	0.993	0.918	0.990	0.580
	2.8	0.784	0.946	0.993	0.911	0.989	0.586

TABLE D.7. DELSOL2 Annual Performance Results for Water/Steam External Receivers with Surround Fields

Power Level (MW_e)	Solar Multiple	Cosine	Shadowing	Blocking	Atmos. Trans.	Spillage	Total
0.5	1.0	0.817	0.966	0.900	0.981	0.622	0.383
	1.2	0.817	0.964	0.906	0.981	0.650	0.402
	1.6	0.809	0.963	0.913	0.980	0.690	0.425
	2.0	0.793	0.961	0.918	0.981	0.730	0.442
	2.4	0.779	0.960	0.923	0.981	0.751	0.449
	2.8	0.760	0.962	0.925	0.981	0.760	0.445
2.0	1.0	0.746	0.962	0.924	0.981	0.779	0.447
	1.2	0.746	0.961	0.936	0.980	0.807	0.469
	1.6	0.737	0.962	0.946	0.979	0.834	0.484
	2.0	0.732	0.962	0.951	0.978	0.874	0.505
	2.4	0.736	0.961	0.951	0.977	0.912	0.529
	2.8	0.734	0.961	0.955	0.976	0.927	0.538
10.0	1.0	0.733	0.960	0.966	0.971	0.936	0.546
	1.2	0.738	0.959	0.969	0.970	0.954	0.560
	1.6	0.733	0.959	0.974	0.967	0.961	0.562
	2.0	0.735	0.958	0.978	0.964	0.973	0.570
	2.4	0.733	0.958	0.979	0.961	0.973	0.568
	2.8	0.735	0.958	0.981	0.959	0.983	0.576
30.0	1.0	0.735	0.958	0.981	0.960	0.979	0.573
	1.2	0.741	0.957	0.982	0.958	0.984	0.580
	1.6	0.735	0.957	0.986	0.953	0.986	0.576
	2.0	0.733	0.957	0.988	0.948	0.989	0.573
	2.4	0.738	0.956	0.989	0.945	0.990	0.576
	2.8	0.741	0.956	0.990	0.941	0.992	0.578
100.0	1.0	0.732	0.957	0.990	0.939	0.991	0.570
	1.2	0.747	0.955	0.991	0.935	0.990	0.578
	1.6	0.738	0.956	0.992	0.927	0.993	0.569
	2.0	0.735	0.956	0.993	0.920	0.994	0.563
	2.4	0.748	0.954	0.993	0.914	0.994	0.569
	2.8	0.742	0.955	0.993	0.909	0.994	0.562

D.5 POSSIBILITIES FOR IMPROVEMENTS IN PERFORMANCE AND/OR LEVELIZED ENERGY COST

Several possibilities exist for improving the performance and/or levelized energy cost of the central receiver systems in this study. In particular the performance of the smaller system could be improved through changes in receiver or heliostat design.

D.5.1 Decreased Levelized Energy Cost Through a Consistent Set of Code Inputs

The DELSOL2 computer code optimizes the design of a central receiver plant based on user supplied inputs and default values already in the code. The optimization is based on producing a system of the desired size with the minimum levelized energy cost. In order to perform this optimization the code must make trade-offs between cost and performance in the design of the system. Thus, the more accurately the code models the performance and cost of the various components the better the design (i.e., the more certain you are that the code has indeed picked the optimal design). For example, if the costs of heliostats is actually twice what it should be, then the code would select a design with less heliostats and less spillage than the optimal design. Thus, in this study the designs could have been improved by having the code use the actual cost and performance algorithms developed for this study, instead of the code default cost and performance algorithms. However, since the designs were developed before the cost and performance algorithms, this was not possible.

D.5.2 Improved Performance for Small Systems

The performance of small system could be improved in at least two ways. It is likely that these improvements would decrease the levelized energy cost but the magnitude of the decrease is unknown.

D.5.2.1 Billboard versus Cylindrical External Receivers

As Table D.2 shows the design average incident flux is much lower for small systems than for large systems. Other things being the same, the higher the average flux, the lower the receiver thermal loss percentage. Thus, high average flux receiver designs are preferable to designs with low average flux. However, with small systems spillage is also very large (see Table D.6); to obtain a higher average flux without changing the design or exceeding the peak flux limit, higher spillage usually results.

One possible way of mitigating this problem for external receivers is to use a billboard design with a north field instead of the cylindrical design and surround field. For example, the sodium external 0.5 MW_e, solar multiple 1.0 design has a design average incident flux of 0.165 MW_t/m^2 and the salt cavity design has a design average aperture flux of 0.337 MW_t/m^2 (Tables D.1 and D.2). This difference occurs because the surface area of the cylindrical receiver is more than twice the aperture area of the cavity receiver. If the receiver aperture were actually a billboard receiver of the same size, then the external receiver would have a much high average flux and correspondingly lower thermal losses than the cylindrical receiver design. In addition, the spillage losses would be slightly reduced (Table D.5 and D.6). This would result in a dramatic improvement in solar-to-electric conversion efficiency.

How this design change would effect the overall levelized energy costs for small sodium external receivers has not been determined; but, it could result in a significant reduction. The improvements in performance and levelized energy cost for a water/steam system would not be as significant as these designs are constrained by a maximum average flux.

D.5.2.2 Small Heliostats and Heliostat Focusing Effects for Small Systems

In general, the effect of astigmatism (off-axis aberrations) is less in small systems (less than 30MWe) when smaller heliostats are used. To determine the effect of different heliostat sizes and configurations on the performance of small systems several DELSOL2 runs were made.

In Table D.8 below are the various heliostat configurations that were used to find optimal designs using DELSOL2. The system being considered was .5MWe at a solar multiple of 1. This is the smallest central receiver system in the current study and will show the greatest effects of changes in heliostat size or configuration. Case A is the base case (1600 ft^2 ARCO heliostat); this heliostat was used for all of the central receiver system designs in this study. Case B is the same heliostat as in Case A except the modules of each heliostat are focused at the slant range for that heliostat instead of at the slant range of the most distant heliostat. There are six other heliostat designs that were evaluated and these are arranged in pairs such that the first case has focusing like Case A and the second one has focusing like Case B.

Cases C and D consider a heliostat of the same overall dimensions as the base case but with different module dimensions. In these cases, the heliostat is made up of twenty-five 8' by 8' mirror modules in a 5 by 5 matrix; while the base case has twenty 4' by 20' mirror modules in a 2 by 10 matrix. None of the 1600 ft^2 heliostat design (Cases A through D) accurately models the ARCO heliostat which consists of twenty 4' by 20' mirror modules that may be individually canted. On the ARCO heliostat each of the modules consists of five 4' by 4' mirror panels, rather than one 4' by 20' panel as modeled in the base case. Thus, each mirror module actually has five focused panels, instead of one. It is not possible to exactly model this heliostat in DELSOL2, but the base case is a good approximation.

TABLE D.8. Heliostat Inputs to DELSOL2 for Cases A Through H

Case	Module Configuration	Mirror Module Focal Length	Module Size (ft^2)	Number of Modules per Heliostat	Mirror Area (ft^2)
A.	2 x 10	8.8 THT	80	20	1600
B.	2 x 10	slant	80	20	1600
C.	5 x 5	8.8 THT	64	25	1600
D.	5 x 5	slant	64	25	1600
E.	5 x 5	8.8 THT	16	25	400
F.	5 x 5	slant	16	25	400
G.	5 x 5	8.8 THT	6.4	25	160
H.	5 x 5	slant	6.4	25	160

Assumptions:

1. All heliostat costs are the same, (DELSOL2 default).
2. All heliostats are canted at the slant range.
3. All other heliostat parameters (e.g., reflectivity, surface errors, tracking errors, etc.) are the same as used in the base case.

The last four cases consider smaller heliostats than were used in the base case. Cases E and F are 400 ft^2 heliostats and Cases G and H are 160 ft^2 heliostats. These heliostats are 25% and 10% of the size used in the first four cases, respectively. For all four cases the mirror modules are assumed to be square and configured in a 5 x 5 layout. These heliostats do not represent designs that necessarily exist in the marketplace. Instead, the linear dimensions of the heliostats used in cases C and D are reduced proportionally such that the smaller heliostats are geometrically similar (same height to width ratio), and the heliostat mirror density is the same (ratio of mirror area to total area of the heliostat).

TABLE D.9. DELSOL2 Design Results

Case	THT	Aperture Width	Aperture Area	Cavity Depth	Number of Heliostats	Mirror Area	Heliostat Density
A.	23	2.8	7.84	1.40	33	4909	0.135
B.	20	2.6	6.76	1.45	27	4086	0.133
C.	22	2.8	7.84	1.80	28	4159	0.138
D.	20	2.5	6.25	1.45	29	4241	0.132
E.	17	2.0	4.00	1.65	97	3623	0.137
F.	17	1.9	3.61	1.50	92	3434	0.139
G.	16	1.7	2.89	1.65	229	3401	0.147
H.	16	1.6	2.56	1.60	227	3370	0.149

Assumptions:

1. The receiver aperture is square.
2. Tower height was varied in 1 meter increments.
3. Aperture height/width was varied in 0.1 meter increments.
4. Cavity depth was varied in 0.05 meter increments.

Table D.9 shows the DELSOL2 system design results for the various heliostat configurations. Several important points should be made about these results. In all cases, focusing at the slant range resulted in a significant reduction in the receiver aperture area. Additionally, in most cases this also reduced the required number of heliostats. When comparing designs with the same mirror panel focusing scheme, reducing the size of the heliostat reduced the required total mirror area. This in turn reduces the necessary tower height.

A detailed SOLSTEP analysis of each of the different case (A. through H.) was not done. However, DELSOL2 results were available to make estimates of changes in thermal efficiency. As can be seen in Tables D.10 and D.11 the design point and annual thermal efficiency of the systems increases greatly (over 50%) as the size of the heliostats is reduced. This is due mostly to three factors: reduced shadowing and blocking, decreased spillage, and the up to 65% reduction in receiver aperture area (Tables D.9 through D.11). Cosine losses showed very little variation with changes in either heliostat size or focusing.

TABLE D.10. DELSOL2 Design Point Performance Results

Case	Cosine	Shadow & Block	Spillage	Receiver[1] Efficiency	Thermal[2] Efficiency
A.	.911	.919	.749	.855	.469
B.	.907	.917	.923	.877	.592
C.	.915	.921	.935	.863	.596
D.	.905	.917	.901	.888	.583
E.	.900	.989	.897	.921	.649
F.	.903	.988	.923	.927	.674
G.	.900	.995	.907	.904	.675
H.	.902	.994	.908	.947	.681

Assumptions:

1. Receiver efficiency is based on the DELSOL2 design point estimate of radiation and convection losses.
2. The solar-to-useable-thermal efficiency is the DELSOL2 estimate of energy to the turbine at design point divided by the product of the design point insolation ($950 W/m^2$) and the mirror area.

In most cases, having the mirror modules focused at the slant range also showed some improvement in thermal efficiency over having all the mirror modules with a focal length equal to the slant range of the most distant heliostat (8.8 tower heights). This improved efficiency is mostly due to increased receiver efficiency (smaller aperture). The percentage improvement in thermal efficiency due to focusing at the slant range decreases with decreasing heliostat size (Tables D.10 and D.11).

TABLE D.11. DELSOL2 Annual Performance Results

Case	Cosine	Shadow & Block	Spillage	Receiver[1] Efficiency	Thermal[2] Efficiency	Relative[3] Cost	Relative[3] LEC
A.	.832	.877	.685	.778	.341	1.0000	1.0000
B.	.829	.874	.789	.800	.403	0.9451	0.9424
C.	.836	.877	.806	.781	.407	0.9634	0.9691
D.	.827	.874	.767	.816	.398	0.9573	0.9441
E.	.823	.928	.826	.877	.486	0.8963	0.8639
F.	.825	.927	.845	.885	.503	0.8780	0.8440
G.	.823	.941	.861	.909	.532	0.8780	0.8240
H.	.824	.940	.858	.918	.536	0.8720	0.8171

Assumptions:

1. Receiver efficiency is based on the DELSOL2 estimate of the annual average radiation and convection losses.
2. The solar-to-useable-thermal efficiency is the DELSOL2 estimate of annual average energy to the turbine divided by the product of the annual insolation ($950 W/m^2$) and the mirror area.
3. DELSOL2 estimate.

Using smaller heliostats results in a smaller total required mirror area. It also reduces the non-heliostat component costs; this is due to differences in the optimal designs. The smaller heliostats allow the tower height and mirror area to be decreased by as much as 30% and the receiver is also considerably smaller. Since the fixed costs ($500,000) and turbine cost do not change, and represent a large percentage of the total cost in a small system, the DELSOL2 estimate of levelized energy cost (LEC), relative to the base case, does not decline as rapidly as the increase in the thermal efficiency and the decrease in component costs (Table D.11).

Clearly, the effect of heliostat size and configuration on the design and performance of small central receiver systems is very significant. However, whether in fact using smaller heliostats would be cost effective (i.e., lower the levelized energy cost) would depend on the actual cost of the heliostats. Certainly, small heliostats will cost more per square meter; but, since a smaller total mirror area is required, and the cost of the tower and receiver would be reduced, a detailed analysis would be required to determine for small systems the heliostat size that would result in the minimum levelized energy cost.

These results were shown only for a cavity receiver with a north field. The effect could be even more pronounced with small surround fields; however, as Section D.5.2.1 explains, a surround field is probably not optimal at small field sizes.

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APPENDIX E

PLANT COST AND SENSITIVITY ANALYSIS

APPENDIX E

PLANT COST AND SENSITIVITY ANALYSIS

This appendix presents a breakdown of plant cost for each of the technologies. The data shows total estimated costs (in 1984 dollars), unit costs, and the approximate contribution to the LEC of each cost component.

Data are presented in Table E.1 through E.30 for the six technologies. The tables cover each power level that was analyzed in the study. Each table provides a cost breakdown at a single power level for two capacity factors; the first capacity factor is for the no-storage case, and the second case is for a plant design near 0.4 capacity factor.

The data in the tables can be used for simple sensitivity analysis to assess the impact of changes is plant component costs on the overall plant LEC. For example, the no-storage CR-Salt system described in Table E.1 uses heliostats which cost $100/m^2. The total LEC for the system is 68 mills/kWh, of which the heliostats make up about 15 mills/kWh. If the heliostat cost for the plant was $200/m^2 instead of $100/m^2, then the contribution of the heliostats to the plant LEC would be about 30 mills/kWh, and the total plant LEC would be about 83 mills/kWh.

Sensitivity analyses such as the one above should be considered approximate for two reasons. First, it is likely that significant changes in the cost of any one component may also affect other plant costs. For example, annual maintenance costs would probably be affected if a component cost significantly more or less than the baseline value. Plant indirect and contingency costs are also likely to be affected by significant changes in the costs of plant components. The second reason that the type of sensitivity analysis described gives only approximate results is because changing the cost of any component in an optimal plant design means that the plant could be re-optimized based on the new component costs. For example, much lower cost heliostats would affect the optimization of the receiver, which would impact on both the plant efficiency and cost. For these reasons, general sensitivity analyses based on simply adjusting the LEC contribution of any one plant component should be looked on as first-order approximations to the actual system LEC.

TABLE E.1. Plant Cost Breakdown for Two CR-Salt Systems at 100 MWe

Collector Field Size, M2	481,312
Storage Size, MWht	0
Plant Capacity Factor:	0.235

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	172931688	$1,729 /kWe	55
O&M Costs (Annual)	2720667	$6 /M2	13
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			68

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	48131200	$100 /M2	15.1
Receiver Cost	16710615	$35 /M2	5.2
Energy Transport Cost	6233513	$13 /M2	2.0
Energy Conversion Cost	37352168	$374 /kWe	11.7
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	19670052	$197 /kWe	6.8
Indirects and Contingencies	44834140	$448 /kWe	14.0

Collector Field Size, M2	824,979
Storage Size, MWht	780.5
Plant Capacity Factor:	0.383

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	265973198	$2,660 /kWe	52
O&M Costs (Annual)	3802795	$5 /M2	11
Replacement Capital	1107577	$11 /kWe	0

TOTAL LEVELIZED ENERGY COST			63

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	82497900	$100 /M2	15.8
Receiver Cost	26136846	$32 /M2	5.0
Energy Transport Cost	11037475	$13 /M2	2.1
Energy Converstion Cost	38107484	$381 /kWe	7.3
Energy Storage Cost	11585213	$15 /kWht	2.2
Other Plant Costs	27652268	$277 /kWe	6.0
Indirects And Contingencies	68956012	$690 /kWe	13.2

TABLE E.2. Plant Cost Breakdown for Two CR-Salt Systems at 30 MWe

Collector Field Size, M2	156,672
Storage Size, MWht	0
Plant Capacity Factor:	0.236

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	66032230	$2,201 /kWe	69
O&M Costs (Annual)	1337764	$9 /M2	22
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			91

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	15667200	$100 /M2	16.3
Receiver Cost	7922974	$51 /M2	8.2
Energy Transport Cost	1748167	$11 /M2	1.8
Energy Conversion Cost	15782070	$526 /kWe	16.4
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	7792353	$260 /kWe	8.9
Indirects And Contingencies	17119466	$571 /kWe	17.8

Collector Field Size, M2	261,466
Storage Size, MWht	257
Plant Capacity Factor	0.385

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	96143450	$3,205 /kWe	62
O&M Costs (Annual)	1686069	$6 /M2	17
Replacement Capital	364804	$12 /kWe	0

TOTAL LEVELIZED ENERGY COST			79

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	26146600	$100 /M2	16.6
Receiver Cost	11320858	$43 /M2	7.2
Energy Transport Cost	2902424	$11 /M2	1.8
Energy Conversion Cost	15983881	$533 /kWe	10.2
Energy Storage Cost	4499997	$18 /kWht	2.9
Other Plant Costs	10363611	$345 /kWe	7.4
Indirects And Contingencies	24926079	$831 /kWe	15.9

TABLE E.3. Plant Cost Breakdown for Two CR-Salt Systems at 10 MWe

Collector Field Size, M2	59,970
Storage Size, MWht	0
Plant Capacity Factor:	0.237

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	29296941	$2,930 /kWe	91
O&M Costs (Annual)	750733	$13 /M2	36
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			127

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	5997000	$100 /M2	18.6
Receiver Cost	4200920	$70 /M2	13.0
Energy Transport Cost	683040	$11 /M2	2.1
Energy Conversion Cost	7221871	$722 /kWe	22.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	3598724	$360 /kWe	11.8
Indirects And Contingencies	7595386	$760 /kWe	23.5

Collector Field Size, M2	81,070
Storage Size, MWht	185
Plant Capacity Factor:	0.391

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	39797141	$3,980 /kWe	75
O&M Costs (Annual)	878937	$11 /M2	26
Replacement Capital	262540	$26 /kWe	1
TOTAL LEVELIZED ENERGY COST			101

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	8107000	$100 /M2	15.2
Receiver Cost	5130066	$63 /M2	9.6
Energy Transport Cost	915446	$11 /M2	1.7
Energy Conversion Cost	7266878	$727 /kWe	13.6
Energy Storage Cost	3823223	$21 /kWht	7.2
Other Plant Costs	4236751	$424 /kWe	8.5
Indirects And Contingencies	10317777	$1,032 /kWe	19.4

TABLE E.4. Plant Cost Breakdown for Two CR-Salt Systems at 2 MWe

Collector Field Size, M2	19,010
Storage Size, MWht	0
Plant Capacity Factor:	0.273

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	10414633	$5,207 /kWe	138
O&M Costs (Annual)	525552	$28 /M2	110
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			247

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1901000	$100 /M2	25.0
Receiver Cost	1913139	$101 /M2	25.2
Energy Transport Cost	231884	$12 /M2	3.1
Energy Conversion Cost	2312495	$1,156 /kWe	30.4
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	1356025	$678 /kWe	18.6
Indirects And Contingencies	2700090	$1,350 /kWe	35.5

Collector Field Size, M2	19,010
Storage Size, MWht	40.4
Plant Capacity Factor:	0.397

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	12592113	$6,296 /kWe	114
O&M Costs (Annual)	555122	$29 /M2	80
Replacement Capital	57404	$29 /kWe	1
TOTAL LEVELIZED ENERGY COST			195

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1901000	$100 /M2	17.2
Receiver Cost	1913139	$101 /M2	17.3
Energy Transport Cost	231884	$12 /M2	2.1
Energy Conversion Cost	2312495	$1,156 /kWe	20.9
Energy Storage Cost	1565969	$39 /kWht	14.2
Other Plant Costs	1403004	$702 /kWe	13.2
Indirects And Contingencies	3264622	$1,632 /kWe	29.5

TABLE E.5. Plant Cost Breakdown for Two CR-Salt Systems at 0.5 MWe

Collector Field Size, M2	8,180
Storage Size, MWht	0
Plant Capacity Factor:	0.284

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	5212513	$10,425 /kWe	265
O&M Costs (Annual)	457972	$56 /M2	367
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			632

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	818000	$100 /M2	41.4
Receiver Cost	1298261	$159 /M2	65.7
Energy Transport Cost	158665	$19 /M2	8.0
Energy Conversion Cost	870116	$1,740 /kWe	44.0
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	716079	$1,432 /kWe	37.4
Indirects And Contingencies	1351392	$2,703 /kWe	68.4

Collector Field Size, M2	7,003
Storage Size, MWht	10.5
Plant Capacity Factor:	0.431

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	6049238	$12,098 /kWe	202
O&M Costs (Annual)	470836	$67 /M2	249
Replacement Capital	15006	$30 /kWe	1
TOTAL LEVELIZED ENERGY COST			452

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	700300	$100 /M2	23.3
Receiver Cost	1157779	$165 /M2	38.6
Energy Transport Cost	146465	$21 /M2	4.9
Energy Conversion Cost	865405	$1,731 /kWe	28.8
Energy Storage Cost	903567	$86 /kWht	30.1
Other Plant Costs	707401	$1,415 /kWe	24.3
Indirects And Contingencies	1568321	$3,137 /kWe	52.3

TABLE E.6. Plant Cost Breakdown for Two CR-Na Systems at 100 MWe

Collector Field Size, M2	519,900
Storage Size, MWht	0
Plant Capacity Factor:	0.243

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	167131396	$1,671 /kWe	51
O&M Costs (Annual)	2693813	$5 /M2	13
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			64

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	51990000	$100 /M2	15.7
Receiver Cost	9952235	$19 /M2	3.0
Energy Transport Cost	6864529	$13 /M2	2.1
Energy Conversion Cost	34778486	$348 /kWe	10.5
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	20215785	$202 /kWe	6.8
Indirects And Contingencies	43330361	$433 /kWe	13.1

Collector Field Size, M2	847,400
Storage Size, MWht	770
Plant Capacity Factor:	0.38

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	259731833	$2,597 /kWe	51
O&M Costs (Annual)	3799029	$4 /M2	11
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			62

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	84740000	$100 /M2	16.4
Receiver Cost	16275490	$19 /M2	3.1
Energy Transport Cost	11370602	$13 /M2	2.2
Energy Conversion Cost	35180176	$352 /kWe	6.8
Energy Storage Cost	16920271	$22 /kWht	3.3
Other Plant Costs	27907413	$279 /kWe	6.1
Indirects And Contingencies	67337881	$673 /kWe	13.0

TABLE E.7. Plant Cost Breakdown for Two CR-Na Systems at 30 MWe

Collector Field Size, M2	174,000
Storage Size, MWht	0
Plant Capacity Factor:	0.241

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	63159354	$2,105 /kWe	65
O&M Costs (Annual)	1323704	$8 /M2	21
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			86

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	17400000	$100 /M2	17.7
Receiver Cost	4378634	$25 /M2	4.5
Energy Transport Cost	2105292	$12 /M2	2.1
Energy Conversion Cost	14852666	$495 /kWe	15.1
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	8048115	$268 /kWe	9.0
Indirects And Contingencies	16374647	$546 /kWe	16.7

Collector Field Size, M2	282,900
Storage Size, MWht	254
Plant Capacity Factor:	0.383

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	94841893	$3,161 /kWe	62
O&M Costs (Annual)	1701674	$6 /M2	17
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			78

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	28290000	$100 /M2	18.1
Receiver Cost	6475307	$23 /M2	4.1
Energy Transport Cost	3603647	$13 /M2	2.3
Energy Conversion Cost	14945926	$498 /kWe	9.6
Energy Storage Cost	6209809	$24 /kWht	4.0
Other Plant Costs	10728566	$358 /kWe	7.7
Indirects And Contingencies	24588638	$820 /kWe	15.7

TABLE E.8. Plant Cost Breakdown for Two CR-Na Systems at 10 MWe

Collector Field Size, M2	68,470
Storage Size, MWht	0
Plant Capacity Factor:	0.24

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	27741414	$2,774 /kWe	86
O&M Costs (Annual)	740045	$11 /M2	35
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			121

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	6847000	$100 /M2	20.9
Receiver Cost	2465186	$36 /M2	7.5
Energy Transport Cost	653305	$10 /M2	2.0
Energy Conversion Cost	6853041	$685 /kWe	20.9
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	3730664	$373 /kWe	12.2
Indirects And Contingencies	7192218	$719 /kWe	22.0

Collector Field Size, M2	87,540
Storage Size, MWht	184
Plant Capacity Factor:	0.383

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	38321687	$3,832 /kWe	74
O&M Costs (Annual)	874604	$10 /M2	26
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			100

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	8754000	$100 /M2	16.8
Receiver Cost	2912122	$33 /M2	5.6
Energy Transport Cost	915689	$10 /M2	1.8
Energy Conversion Cost	6867821	$687 /kWe	13.1
Energy Storage Cost	4605574	$25 /kWht	8.8
Other Plant Costs	4331229	$433 /kWe	8.9
Indirects And Contingencies	9935252	$994 /kWe	19.0

TABLE E.9. Plant Cost Breakdown for Two CR-Na Systems at 2 MWe

Collector Field Size, M2	24,870
Storage Size, MWht	0
Plant Capacity Factor:	0.26

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	11066120	$5,533 /kWe	154
O&M Costs (Annual)	534395	$21 /M2	117
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			271

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	2487000	$100 /M2	34.4
Receiver Cost	1674884	$67 /M2	23.1
Energy Transport Cost	325004	$13 /M2	4.5
Energy Conversion Cost	2216108	$1,108 /kWe	30.6
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	1494130	$747 /kWe	21.7
Indirects And Contingencies	2868994	$1,434 /kWe	39.6

Collector Field Size, M2	24,870
Storage Size, MWht	40.5
Plant Capacity Factor:	0.435

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	13085507	$6,543 /kWe	109
O&M Costs (Annual)	561818	$23 /M2	74
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			182

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	2487000	$100 /M2	20.5
Receiver Cost	1674884	$67 /M2	13.8
Energy Transport Cost	325004	$13 /M2	2.7
Energy Conversion Cost	2216108	$1,108 /kWe	18.3
Energy Storage Cost	1452274	$36 /kWht	12.0
Other Plant Costs	1537698	$769 /kWe	13.3
Indirects And Contingencies	3392539	$1,696 /kWe	28.0

TABLE E.10. Plant Cost Breakdown for Two CR-Na Systems at 0.5 MWe

Collector Field Size, M2	10,300
Storage Size, MWht	0
Plant Capacity Factor:	0.258

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	5385425	$10,771 /kWe	301
O&M Costs (Annual)	460515	$45 /M2	407
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			708

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1030000	$100 /M2	57.3
Receiver Cost	1174618	$114 /M2	65.4
Energy Transport Cost	181280	$18 /M2	10.1
Energy Conversion Cost	835350	$1,671 /kWe	46.5
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	767956	$1,536 /kWe	44.4
Indirects And Contingencies	1396221	$2,792 /kWe	77.7

Collector Field Size, M2	8,856
Storage Size, MWht	10.8
Plant Capacity Factor:	0.405

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	6025593	$12,051 /kWe	215
O&M Costs (Annual)	470368	$53 /M2	265
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			479

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	885600	$100 /M2	31.4
Receiver Cost	1096420	$124 /M2	38.9
Energy Transport Cost	167036	$19 /M2	5.9
Energy Conversion Cost	834194	$1,668 /kWe	29.6
Energy Storage Cost	731179	$68 /kWht	25.9
Other Plant Costs	748973	$1,498 /kWe	27.5
Indirects And Contingencies	1562191	$3,124 /kWe	55.4

TABLE E.11. Plant Cost Breakdown for Two CR-Na/S Systems at 100 MWe

Collector Field Size, M2	519,900
Storage Size, MWht	0
Plant Capacity Factor:	0.25

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	171046185	$1,710 /kWe	51
O&M Costs (Annual)	2731460	$5 /M2	12
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			63

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	51990000	$100 /M2	15.3
Receiver Cost	9952235	$19 /M2	2.9
Energy Transport Cost	7431308	$14 /M2	2.2
Energy Conversion Cost	37027089	$370 /kWe	10.9
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	20300247	$203 /kWe	6.6
Indirects And Contingencies	44345306	$443 /kWe	13.0

Collector Field Size, M2	847,400
Storage Size, MWht	1560
Plant Capacity Factor:	0.447

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	269291214	$2,693 /kWe	45
O&M Costs (Annual)	3912674	$5 /M2	10
Replacement Capital	2214033	$22 /kWe	0

TOTAL LEVELIZED ENERGY COST			55

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	84740000	$100 /M2	13.9
Receiver Cost	16275490	$19 /M2	2.7
Energy Transport Cost	11918254	$14 /M2	2.0
Energy Conversion Cost	37523807	$375 /kWe	6.2
Energy Storage Cost	20903768	$13 /kWht	3.4
Other Plant Costs	28113656	$281 /kWe	5.2
Indirects And Contingencies	69816239	$698 /kWe	11.5

TABLE E.12. Plant Cost Breakdown for Two CR-Na/S Systems at 30 MWe

Collector Field Size, M2	174,000
Storage Size, MWht	0
Plant Capacity Factor:	0.246

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	65075582	$2,169 /kWe	66
O&M Costs (Annual)	1344268	$8 /M2	21
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			86

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	17400000	$100 /M2	17.3
Receiver Cost	4378634	$25 /M2	4.4
Energy Transport Cost	2692271	$15 /M2	2.7
Energy Conversion Cost	15643772	$521 /kWe	15.6
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	8089458	$270 /kWe	8.9
Indirects And Contingencies	16871447	$562 /kWe	16.8

Collector Field Size, M2	282,900
Storage Size, MWht	254
Plant Capacity Factor:	0.372

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	94363556	$3,145 /kWe	63
O&M Costs (Annual)	1689525	$6 /M2	17
Replacement Capital	361184	$12 /kWe	0

TOTAL LEVELIZED ENERGY COST			81

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	28290000	$100 /M2	18.6
Receiver Cost	6475307	$23 /M2	4.3
Energy Transport Cost	4184266	$15 /M2	2.8
Energy Conversion Cost	15765266	$526 /kWe	10.4
Energy Storage Cost	4465846	$18 /kWht	2.9
Other Plant Costs	10718246	$357 /kWe	7.9
Indirects And Contingencies	24464625	$815 /kWe	16.1

TABLE E.13. Plant Cost Breakdown for Two CR-Na/S Systems at 10 MWe

Collector Field Size, M2	68,470
Storage Size, MWht	0
Plant Capacity Factor:	0.242

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	28699135	$2,870 /kWe	88
O&M Costs (Annual)	751988	$11 /M2	35
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			123

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	6847000	$100 /M2	20.7
Receiver Cost	2465186	$36 /M2	7.5
Energy Transport Cost	1042969	$15 /M2	3.2
Energy Conversion Cost	7152137	$715 /kWe	21.7
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	3751327	$375 /kWe	12.1
Indirects And Contingencies	7440516	$744 /kWe	22.5

Collector Field Size, M2	87,540
Storage Size, MWht	185
Plant Capacity Factor:	0.388

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	38221448	$3,822 /kWe	73
O&M Costs (Annual)	870962	$10 /M2	26
Replacement Capital	262566	$26 /kWe	1

TOTAL LEVELIZED ENERGY COST			99

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	8754000	$100 /M2	16.5
Receiver Cost	2912122	$33 /M2	5.5
Energy Transport Cost	1295188	$15 /M2	2.4
Energy Conversion Cost	7198323	$720 /kWe	13.6
Energy Storage Cost	3823485	$21 /kWht	7.2
Other Plant Costs	4329066	$433 /kWe	8.8
Indirects And Contingencies	9909264	$991 /kWe	18.7

TABLE E.14. Plant Cost Breakdown for Two CR-Na/S Systems at 2 MWe

Collector Field Size, M2	24,870
Storage Size, MWht	0
Plant Capacity Factor:	0.263

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	11371247	$5,686 /kWe	158
O&M Costs (Annual)	537999	$22 /M2	116
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			274

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	2487000	$100 /M2	34.0
Receiver Cost	1674884	$67 /M2	22.9
Energy Transport Cost	466319	$19 /M2	6.4
Energy Conversion Cost	2294230	$1,147 /kWe	31.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	1500713	$750 /kWe	22.8
Indirects And Contingencies	2948101	$1,474 /kWe	40.3

Collector Field Size, M2	24,870
Storage Size, MWht	40.5
Plant Capacity Factor:	0.44

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	13560621	$6,780 /kWe	112
O&M Costs (Annual)	567676	$23 /M2	73
Replacement Capital	57438	$29 /kWe	1

TOTAL LEVELIZED ENERGY COST			186

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	2487000	$100 /M2	20.3
Receiver Cost	1674884	$67 /M2	13.7
Energy Transport Cost	466319	$19 /M2	3.8
Energy Conversion Cost	2302179	$1,151 /kWe	18.8
Energy Storage Cost	1566575	$39 /kWht	12.8
Other Plant Costs	1547948	$774 /kWe	14.0
Indirects And Contingencies	3515716	$1,758 /kWe	28.7

TABLE E.15. Plant Cost Breakdown for Two CR-Na/S Systems at 0.5 MWe

Collector Field Size, M2	10,300
Storage Size, MWht	0
Plant Capacity Factor:	0.262

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	5552331	$11,105 /kWe	306
O&M Costs (Annual)	462590	$45 /M2	402
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			708

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1030000	$100 /M2	56.5
Receiver Cost	1174618	$114 /M2	64.4
Energy Transport Cost	273617	$27 /M2	15.0
Energy Conversion Cost	863046	$1,726 /kWe	47.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	771557	$1,543 /kWe	44.0
Indirects And Contingencies	1439493	$2,879 /kWe	78.9

Collector Field Size, M2	8,856
Storage Size, MWht	10.6
Plant Capacity Factor:	0.418

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	6428704	$12,857 /kWe	222
O&M Costs (Annual)	475635	$54 /M2	259
Replacement Capital	15006	$30 /kWe	1
TOTAL LEVELIZED ENERGY COST			482

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	885600	$100 /M2	30.4
Receiver Cost	1096420	$124 /M2	37.7
Energy Transport Cost	254519	$29 /M2	8.7
Energy Conversion Cost	864226	$1,728 /kWe	29.7
Energy Storage Cost	903567	$85 /kWht	31.1
Other Plant Costs	757671	$1,515 /kWe	27.0
Indirects And Contingencies	1666701	$3,333 /kWe	57.3

TABLE E.16. Plant Cost Breakdown for Two CR-W/S Systems at 100 MWe

Collector Field Size, M2	581,300
Storage Size, MWht	0
Plant Capacity Factor:	0.241

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	182772778	$1,828 /kWe	57
O&M Costs (Annual)	2846899	$5 /M2	13
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			70

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	58130000	$100 /M2	17.7
Receiver Cost	20161182	$35 /M2	6.2
Energy Transport Cost	5185434	$9 /M2	1.6
Energy Conversion Cost	30289907	$303 /kWe	9.2
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	21620722	$216 /kWe	7.4
Indirects And Contingencies	47385533	$474 /kWe	14.5

Collector Field Size, M2	1,003,000
Storage Size, MWht	2571
Plant Capacity Factor:	0.409

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	327322698	$3,273 /kWe	60
O&M Costs (Annual)	4595501	$5 /M2	13
Replacement Capital	7252246	$73 /kWe	2

TOTAL LEVELIZED ENERGY COST			74

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	100300000	$100 /M2	18.0
Receiver Cost	31099677	$31 /M2	5.6
Energy Transport Cost	9251974	$9 /M2	1.7
Energy Conversion Cost	30660213	$307 /kWe	5.5
Energy Storage Cost	39078516	$15 /kWht	7.0
Other Plant Costs	32070880	$321 /kWe	6.5
Indirects And Contingencies	84861438	$849 /kWe	15.3

TABLE E.17. Plant Cost Breakdown for Two CR-W/S Systems at 30 MWe

Collector Field Size, M2	190,000
Storage Size, MWht	0
Plant Capacity Factor:	0.244

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	68166342	$2,272 /kWe	69
O&M Costs (Annual)	1370090	$7 /M2	21
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			91

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	19000000	$100 /M2	19.1
Receiver Cost	8554723	$45 /M2	8.6
Energy Transport Cost	1472464	$8 /M2	1.5
Energy Conversion Cost	13016867	$434 /kWe	13.1
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	8449533	$282 /kWe	9.4
Indirects And Contingencies	17672755	$589 /kWe	17.8

Collector Field Size, M2	324,000
Storage Size, MWht	520
Plant Capacity Factor:	0.398

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	110202132	$3,673 /kWe	69
O&M Costs (Annual)	1864928	$6 /M2	18
Replacement Capital	1466719	$49 /kWe	1

TOTAL LEVELIZED ENERGY COST			88

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	32400000	$100 /M2	20.0
Receiver Cost	12817386	$40 /M2	7.9
Energy Transport Cost	2496681	$8 /M2	1.5
Energy Conversion Cost	13141557	$438 /kWe	8.1
Energy Storage Cost	8961972	$17 /kWht	5.5
Other Plant Costs	11813614	$394 /kWe	8.2
Indirects And Contingencies	28570922	$952 /kWe	17.6

TABLE E.18. Plant Cost Breakdown for Two CR-W/S Systems at 10 MWe

Collector Field Size, M2	74,840
Storage Size, MWht	0
Plant Capacity Factor:	0.247

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	30168922	$3,017 /kWe	90
O&M Costs (Annual)	764473	$10 /M2	35
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			126

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	7484000	$100 /M2	22.2
Receiver Cost	4331516	$58 /M2	12.9
Energy Transport Cost	591215	$8 /M2	1.8
Energy Conversion Cost	6033222	$603 /kWe	17.9
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	3907397	$391 /kWe	12.4
Indirects And Contingencies	7821572	$782 /kWe	23.

Collector Field Size, M2	123,000
Storage Size, MWht	178.7
Plant Capacity Factor:	0.403

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	46433371	$4,643 /kWe	85
O&M Costs (Annual)	954509	$8 /M2	27
Replacement Capital	504137	$50 /kWe	1
TOTAL LEVELIZED ENERGY COST			113

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	12300000	$100 /M2	22.4
Receiver Cost	6205082	$50 /M2	11.3
Energy Transport Cost	932940	$8 /M2	1.7
Energy Conversion Cost	6090077	$609 /kWe	11.1
Energy Storage Cost	3668483	$21 /kWht	6.7
Other Plant Costs	5198508	$520 /kWe	10.2
Indirects And Contingencies	12038281	$1,204 /kWe	21.9

TABLE E.19. Plant Cost Breakdown for Two CR-W/S Systems at 2 MWe

Collector Field Size, M2	25,030
Storage Size, MWht	0
Plant Capacity Factor:	0.269

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	11141646	$5,571 /kWe	150
O&M Costs (Annual)	534514	$21 /M2	113
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			263

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	2503000	$100 /M2	33.4
Receiver Cost	2046848	$82 /M2	27.3
Energy Transport Cost	237783	$9 /M2	3.2
Energy Conversion Cost	1966294	$983 /kWe	26.2
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	1499146	$750 /kWe	21.0
Indirects And Contingencies	2888575	$1,444 /kWe	38.6

Collector Field Size, M2	30,270
Storage Size, MWht	38.9
Plant Capacity Factor:	0.395

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	14707097	$7,354 /kWe	134
O&M Costs (Annual)	578915	$19 /M2	83
Replacement Capital	109747	$55 /kWe	1

TOTAL LEVELIZED ENERGY COST			219

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	3027000	$100 /M2	27.5
Receiver Cost	2318728	$77 /M2	21.1
Energy Transport Cost	274964	$9 /M2	2.5
Energy Conversion Cost	1977010	$989 /kWe	18.0
Energy Storage Cost	1609450	$41 /kWht	14.6
Other Plant Costs	1686994	$843 /kWe	16.1
Indirects And Contingencies	3812951	$1,906 /kWe	34.7

TABLE E.20. Plant Cost Breakdown for Two CR-W/S Systems at 0.5 MWe

Collector Field Size, M2	10,080
Storage Size, MWht	0
Plant Capacity Factor:	0.281

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	5181617	$10,363 /kWe	267
O&M Costs (Annual)	458324	$45 /M2	372
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			638

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1008000	$100 /M2	51.5
Receiver Cost	1188986	$118 /M2	60.8
Energy Transport Cost	131704	$13 /M2	6.7
Energy Conversion Cost	750982	$1,502 /kWe	38.4
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	758563	$1,517 /kWe	40.4
Indirects And Contingencies	1343382	$2,687 /kWe	68.7

Collector Field Size, M2	10,080
Storage Size, MWht	10.1
Plant Capacity Factor:	0.39

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	6287340	$12,575 /kWe	233
O&M Costs (Annual)	473332	$47 /M2	276
Replacement Capital	28696	$57 /kWe	1
TOTAL LEVELIZED ENERGY COST			511

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1008000	$100 /M2	37.1
Receiver Cost	1188986	$118 /M2	43.8
Energy Transport Cost	131704	$13 /M2	4.9
Energy Conversion Cost	751992	$1,504 /kWe	27.7
Energy Storage Cost	794188	$79 /kWht	29.3
Other Plant Costs	782419	$1,565 /kWe	30.0
Indirects And Contingencies	1630051	$3,260 /kWe	60.0

TABLE E.21. Plant Cost Breakdown for Two Dish Systems at 100 MWe

Collector Field Size, M2	394,740
Storage Size, MWht	0
Plant Capacity Factor:	0.267

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	126281809	$1,263 /kWe	35
O&M Costs (Annual)	8003893	$20 /M2	34
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			69

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	47368800	$120 /M2	13.0
Receiver Cost	8179013	$21 /M2	2.3
Energy Transport Cost	6519958	$17 /M2	1.8
Energy Conversion Cost	19087152	$191 /kWe	5.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	12387159	$124 /kWe	3.7
Indirects And Contingencies	32739727	$327 /kWe	9.0

Collector Field Size, M2	789,470
Storage Size, MWht	607.8
Plant Capacity Factor:	0.418

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	368343915	$3,683 /kWe	65
O&M Costs (Annual)	16859478	$21 /M2	46
Replacement Capital	72459931	$725 /kWe	17

TOTAL LEVELIZED ENERGY COST			129

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	94736400	$120 /M2	16.7
Receiver Cost	16357818	$21 /M2	2.9
Energy Transport Cost	13163251	$17 /M2	2.3
Energy Conversion Cost	38173800	$382 /kWe	6.7
Energy Storage Cost	89138040	$147 /kWht	15.7
Other Plant Costs	21278038	$213 /kWe	4.1
Indirects And Contingencies	95496568	$955 /kWe	16.8

TABLE E.22. Plant Cost Breakdown for Two Dish Systems at 30 MWe

Collector Field Size, M2	118,420
Storage Size, MWht	0
Plant Capacity Factor:	0.269

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	38956606	$1,299 /kWe	36
O&M Costs (Annual)	2457859	$21 /M2	35
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			71

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	14210400	$120 /M2	12.9
Receiver Cost	2453662	$21 /M2	2.2
Energy Transport Cost	1924189	$16 /M2	1.8
Energy Conversion Cost	5726112	$191 /kWe	5.2
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	4542382	$151 /kWe	4.5
Indirects And Contingencies	10099861	$337 /kWe	9.2

Collector Field Size, M2	236,840
Storage Size, MWht	182.3
Plant Capacity Factor:	0.419

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	112565381	$3,752 /kWe	66
O&M Costs (Annual)	5107200	$22 /M2	46
Replacement Capital	22938611	$765 /kWe	18

TOTAL LEVELIZED ENERGY COST			131

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	28420800	$120 /M2	16.6
Receiver Cost	4907325	$21 /M2	2.9
Energy Transport Cost	3884826	$16 /M2	2.3
Energy Conversion Cost	11452056	$382 /kWe	6.7
Energy Storage Cost	27485738	$151 /kWht	16.1
Other Plant Costs	7231020	$241 /kWe	4.7
Indirects And Contingencies	29183616	$973 /kWe	17.1

TABLE E.23. Plant Cost Breakdown for Two Dish Systems at 10 MWe

Collector Field Size, M2	39,470
Storage Size, MWht	0
Plant Capacity Factor:	0.27

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	13711387	$1,371 /kWe	38
O&M Costs (Annual)	870463	$22 /M2	37
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			74

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	4736400	$120 /M2	12.9
Receiver Cost	817818	$21 /M2	2.2
Energy Transport Cost	631832	$16 /M2	1.7
Energy Conversion Cost	1908480	$191 /kWe	5.2
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	2062053	$206 /kWe	6.0
Indirects And Contingencies	3554804	$355 /kWe	9.7

Collector Field Size, M2	78,950
Storage Size, MWht	60.8
Plant Capacity Factor:	0.42

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	39380527	$3,938 /kWe	69
O&M Costs (Annual)	1756889	$22 /M2	48
Replacement Capital	7751614	$775 /kWe	19

TOTAL LEVELIZED ENERGY COST			136

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	9474000	$120 /M2	16.5
Receiver Cost	1635844	$21 /M2	2.9
Energy Transport Cost	1275794	$16 /M2	2.2
Energy Conversion Cost	3817464	$382 /kWe	6.7
Energy Storage Cost	9985609	$164 /kWht	17.4
Other Plant Costs	2981791	$298 /kWe	5.7
Indirects And Contingencies	10210025	$1,021 /kWe	17.8

TABLE E.24. Plant Cost Breakdown for Two Dish Systems at 2 MWe

Collector Field Size, M2	7,890
Storage Size, MWht	0
Plant Capacity Factor:	0.27

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	3156294	$1,578 /kWe	43
O&M Costs (Annual)	232177	$29 /M2	49
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			92

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	946800	$120 /M2	12.6
Receiver Cost	163481	$21 /M2	2.2
Energy Transport Cost	123569	$16 /M2	1.6
Energy Conversion Cost	381528	$191 /kWe	5.1
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	722618	$361 /kWe	10.2
Indirects And Contingencies	818298	$409 /kWe	10.9

Collector Field Size, M2	13,160
Storage Size, MWht	12.1
Plant Capacity Factor:	0.398

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	8006418	$4,003 /kWe	73
O&M Costs (Annual)	359675	$27 /M2	51
Replacement Capital	1661239	$831 /kWe	20

TOTAL LEVELIZED ENERGY COST			144

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1579200	$120 /M2	14.2
Receiver Cost	272675	$21 /M2	2.5
Energy Transport Cost	207542	$16 /M2	1.9
Energy Conversion Cost	636384	$318 /kWe	5.7
Energy Storage Cost	2358644	$195 /kWht	21.3
Other Plant Costs	876235	$438 /kWe	8.5
Indirects And Contingencies	2075738	$1,038 /kWe	18.7

TABLE E.25. Plant Cost Breakdown for Two Dish Systems at 0.5 MWe

Collector Field Size, M2	2,630
Storage Size, MWht	0
Plant Capacity Factor:	0.31

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	1276646	$2,553 /kWe	60
O&M Costs (Annual)	124145	$47 /M2	91
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			151

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	315600	$120 /M2	14.6
Receiver Cost	54494	$21 /M2	2.5
Energy Transport Cost	40580	$15 /M2	1.9
Energy Conversion Cost	127176	$254 /kWe	5.9
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	407814	$816 /kWe	20.0
Indirects And Contingencies	330982	$662 /kWe	15.3

Collector Field Size, M2	3,290
Storage Size, MWht	3
Plant Capacity Factor:	0.398

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	2515583	$5,031 /kWe	92
O&M Costs (Annual)	144082	$44 /M2	82
Replacement Capital	434526	$869 /kWe	21

TOTAL LEVELIZED ENERGY COST			195

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	394800	$120 /M2	14.2
Receiver Cost	68169	$21 /M2	2.5
Energy Transport Cost	50918	$15 /M2	1.8
Energy Conversion Cost	159096	$318 /kWe	5.7
Energy Storage Cost	749734	$250 /kWht	27.1
Other Plant Costs	440678	$881 /kWe	16.8
Indirects And Contingencies	652188	$1,304 /kWe	23.5

TABLE E.26. Plant Cost Breakdown for Two Trough Systems at 100 MWe

Collector Field Size, M2	930,400
Storage Size, MWht	0
Plant Capacity Factor:	0.186

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	360056588	$3,601 /kWe	139
O&M Costs (Annual)	5790820	$6 /M2	35
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			175

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	139560000	$150 /M2	55.2
Receiver Cost	13025600	$14 /M2	5.1
Energy Transport Cost	51353410	$55 /M2	20.3
Energy Conversion Cost	43885028	$439 /kWe	17.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	18884548	$189 /kWe	4.3
Indirects And Contingencies	93348002	$933 /kWe	36.9

Collector Field Size, M2	1,861,000
Storage Size, MWht	3709.8
Plant Capacity Factor:	0.419

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	707192511	$7,072 /kWe	121
O&M Costs (Annual)	11521344	$6 /M2	31
Replacement Capital	10465875	$105 /kWe	3

TOTAL LEVELIZED ENERGY COST			155

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	279150000	$150 /M2	49.0
Receiver Cost	26054000	$14 /M2	4.6
Energy Transport Cost	114533958	$62 /M2	20.1
Energy Conversion Cost	46472075	$465 /kWe	8.2
Energy Storage Cost	27772982	$7 /kWht	4.9
Other Plant Costs	29863294	$299 /kWe	2.6
Indirects And Contingencies	183346202	$1,833 /kWe	32.2

TABLE E.27. Plant Cost Breakdown for Two Trough Systems at 30 MWe

Collector Field Size, M2	276,700
Storage Size, MWht	0
Plant Capacity Factor:	0.19

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	111556911	$3,719 /kWe	141
O&M Costs (Annual)	1940764	$7 /M2	39
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			180

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	41505000	$150 /M2	53.5
Receiver Cost	3873800	$14 /M2	5.0
Energy Transport Cost	12255020	$44 /M2	15.8
Energy Conversion Cost	18067286	$602 /kWe	23.3
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	6933644	$231 /kWe	6.3
Indirects And Contingencies	28922161	$964 /kWe	37.3

Collector Field Size, M2	553,300
Storage Size, MWht	1137.6
Plant Capacity Factor:	0.428

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	209072406	$6,969 /kWe	117
O&M Costs (Annual)	3531332	$6 /M2	31
Replacement Capital	3209532	$107 /kWe	3
TOTAL LEVELIZED ENERGY COST			151

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	82995000	$150 /M2	47.5
Receiver Cost	7746200	$14 /M2	4.4
Energy Transport Cost	26356097	$48 /M2	15.1
Energy Conversion Cost	18732621	$624 /kWe	10.7
Energy Storage Cost	8963881	$8 /kWht	5.1
Other Plant Costs	10074653	$336 /kWe	3.0
Indirects And Contingencies	54203954	$1,807 /kWe	31.0

TABLE E.28. Plant Cost Breakdown for Two Trough Systems at 10 MWe

Collector Field Size, M2	92,250
Storage Size, MWht	0
Plant Capacity Factor:	0.194

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	40207808	$4,021 /kWe	149
O&M Costs (Annual)	926670	$10 /M2	54
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			204

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	13837500	$150 /M2	52.3
Receiver Cost	1291500	$14 /M2	4.9
Energy Transport Cost	3640466	$39 /M2	13.8
Energy Conversion Cost	7996792	$800 /kWe	30.2
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	3017304	$302 /kWe	8.7
Indirects And Contingencies	10424246	$1,042 /kWe	39.4

Collector Field Size, M2	184,500
Storage Size, MWht	254.7
Plant Capacity Factor:	0.394

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	71492416	$7,149 /kWe	130
O&M Costs (Annual)	1434384	$8 /M2	41
Replacement Capital	718687	$72 /kWe	2

TOTAL LEVELIZED ENERGY COST			173

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	27675000	$150 /M2	51.5
Receiver Cost	2583000	$14 /M2	4.8
Energy Transport Cost	7830883	$42 /M2	14.6
Energy Conversion Cost	8079335	$808 /kWe	15.0
Energy Storage Cost	2750967	$11 /kWht	5.1
Other Plant Costs	4038161	$404 /kWe	4.2
Indirects And Contingencies	18535070	$1,854 /kWe	34.5

TABLE E.29. Plant Cost Breakdown for Two Trough Systems at 2 MWe

Collector Field Size, M2	26,830
Storage Size, MWht	0
Plant Capacity Factor:	0.233

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	11926345	$5,963 /kWe	180
O&M Costs (Annual)	546843	$20 /M2	134
Replacement Capital	0	$0 /kWe	0

TOTAL LEVELIZED ENERGY COST			314

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	4024500	$150 /M2	62.0
Receiver Cost	375620	$14 /M2	5.8
Energy Transport Cost	929966	$35 /M2	14.3
Energy Conversion Cost	2433198	$1,217 /kWe	37.5
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	1071046	$536 /kWe	12.7
Indirects And Contingencies	3092015	$1,546 /kWe	47.7

Collector Field Size, M2	33,350
Storage Size, MWht	84.5
Plant Capacity Factor:	0.395

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	16098677	$8,049 /kWe	144
O&M Costs (Annual)	622244	$19 /M2	90
Replacement Capital	238359	$119 /kWe	3

TOTAL LEVELIZED ENERGY COST			236

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	5002500	$150 /M2	45.5
Receiver Cost	466900	$14 /M2	4.2
Energy Transport Cost	1182679	$35 /M2	10.8
Energy Conversion Cost	2444768	$1,222 /kWe	22.2
Energy Storage Cost	1642588	$19 /kWht	14.9
Other Plant Costs	1185511	$593 /kWe	8.1
Indirects And Contingencies	4173731	$2,087 /kWe	37.9

TABLE E.30. Plant Cost Breakdown for Two Trough Systems at 0.5 MWe

Collector Field Size, M2	11,030
Storage Size, MWht	0
Plant Capacity Factor:	0.266

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	4941603	$9,883 /kWe	261
O&M Costs (Annual)	455025	$41 /M2	390
Replacement Capital	0	$0 /kWe	0
TOTAL LEVELIZED ENERGY COST			651

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1654500	$150 /M2	89.3
Receiver Cost	154420	$14 /M2	8.3
Energy Transport Cost	402456	$36 /M2	21.7
Energy Conversion Cost	900891	$1,802 /kWe	48.6
Energy Storage Cost	0	$0 /kWht	0.0
Other Plant Costs	548180	$1,096 /kWe	23.6
Indirects And Contingencies	1281156	$2,562 /kWe	69.2

Collector Field Size, M2	11,030
Storage Size, MWht	15951
Plant Capacity Factor:	0.401

System Cost Summary

	COST, $	UNIT COST	LEC MILLS/KWH
Capital Investment Costs	5957120	$11,914 /kWe	209
O&M Costs (Annual)	475535	$43 /M2	270
Replacement Capital	45000	$90 /kWe	2
TOTAL LEVELIZED ENERGY COST			481

Capital Cost Breakdown

	COST, $	UNIT COST	LEC MILLS/KWH
Concentrator Cost	1654500	$150 /M2	59.3
Receiver Cost	154420	$14 /M2	5.5
Energy Transport Cost	402456	$36 /M2	14.4
Energy Conversion Cost	900891	$1,802 /kWe	32.3
Energy Storage Cost	730325	$0 /kWht	26.2
Other Plant Costs	570089	$1,140 /kWe	15.9
Indirects And Contingencies	1544439	$3,089 /kWe	55.3

APPENDIX F

DISTRIBUTED COMPONENT MANUFACTURED COST MODEL

APPENDIX F

DISTRIBUTED COMPONENT MANUFACTURED COST MODEL

The model used to estimate the manufactured cost of distributed components is presented and described in this appendix. This model was used to help estimate the manufactured cost of concentrators for central receiver, dish, and trough systems, and the receiver for the trough system. Five inputs are required for each component estimate once cost and economic assumptions applicable to all components are specified. The five inputs are the annual direct material cost at the annual production volume, the annual direct labor manhours at the annual production volume, installed factory equipment costs, factory floor area in square feet, and factory land area in acres. The series of equations representing the model are presented in Table F.1 and the general economic assumptions are listed in Table F.2.

Table F.1. Manufactured Cost Model Equations

(1) Burdened Material = Direct Material * 1.10

(2) Burdened Labor = Direct Labor Hours * Labor Rate/hr * 2.50

(3) General and Administrative Costs = ((1) + (2)) * 0.20

(4) Annualized Building Capital = Building Ft^2 * Building Cost/Ft^2 * FCR_b

(5) Annualized Land Capital = Land Acres * Land Cost/Acre * FCR_l * 0.851(a)

(6) Annualized Equipment Capital = Equipment Cost * FCR_e

(7) Annualized Working Capital = 0.30 * ((1) + (2) + (3)) * FCR_{wc} * 0.851(a)

(8) Total Annual Cost = (1) + (2) + (3) + (4) + (5) + (6) + (7)

(9) Unit Cost = (8)/ Annual Production Volume

(a) The additional factor of 0.851 allows for the net present value of the land and working capital investment which will be returned to the investor at the end of the plant life.

Table F.2. Cost and Economic Assumptions

Direct Labor Rate = \$9/hr

Building Unit Cost = \$50/ft^2

Land Unit Cost = \$25,000/acre

FCR_b (Fixed Charge Rate For Factory Structure) = 0.186

FCR_l (Fixed Charge Rate For Factory Land) = 0.245

FCR_e (Fixed Charge Rate For Factory Equipment) = 0.138

FCR_{wc} (Fixed Charge Rate For Factory Working Capital) = 0.245

Note: Factory equipment is assumed to be depreciable over five years and the factory structure is assumed to be depreciable over 10 years according to ACRS depreciation tables. Land and working capital are not depreciable.

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