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VOLUME IV

SOLAR THERMAL CONVERSION MISSION ANALYSIS

Mission/System and Economic Analysis

THE AEROSPACE CORPORATION

Report No. ATR-74(7417-05)-1

SOLAR THERMAL CONVERSION MISSION ANALYSIS

VOLUME IV

MISSION/SYSTEM AND ECONOMIC ANALYSIS

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FOREWORD

This report presents the Mission/System and Economic Analysis results of the Solar Thermal Conversion Mission Analysis performed by The Aerospace Corporation under contract to the National Science Foundation/Research Applied to National Needs. The time period of the contract was from April 15, 1973 to October 15, 1973. This Summary Report is the fourth of five volumes; the remaining four volumes include a Summary Report and describe in detail the findings of the Demand Analysis, Southern California Insolation Climatology Analysis, and Area Definition and Siting Analysis

This study was conducted under NSF Contract C797 by the Energy Programs Group of the Civil Programs Division. Mr. D. F. Spencer was the NSF Program Manager for this contract; and Dr. A. B. Greenberg, General Manager of The Civil Programs Division, was the Principal Investigator. Dr. M. B. Watson, Associate Group Director of The Energy Programs Group was the NSF/RANN Coordinator; and Mr. P. B. Bos, Associate Director, Solar Projects, provided Program Management.

This report was prepared by the following authors: Mr. P. B. Bos, Mr. R. W. Bruce, Dr. P. J. Peters, and Mr. R. M. Selter

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The authors express their sincere appreciation to Mr. M. S. Ensign for producing the tables and figures, to Mr. C. R. Olsen for technical editing, to Mr. H. Fockler for the cover design, and to Ms. Anita Diekelman for the typing and preparing of this document.

ABSTRACT

This report describes the mission/systems and economic analyses performed to examine the dynamic interaction of insolation, demand, and solar power systems. These analyses utilized the hourly demand projections and regional insolation data described in the previous volumes. A methodology was developed to parametrically assess the performance characteristics of alternative solar thermal conversion missions and systems in realistic operating environments on a consistent basis. This model permits the simulation of one or more solar power plants integrated into a power grid on an hour-by-hour basis for at least a full year. When more detailed subsystem descriptions, representative of the alternative solar power plants, become available from various system design studies now under way, the subroutines will be increased in complexity to more accurately reflect the system design characteristics and to examine the effect and sensitivity of the major design parameters.

To ensure against the probability that the electrical load or demand exceeds the available generating capacity for a particular electric power utility, the installed generating capacity for United States utility companies is designed to be in excess of the anticipated peak loads. This incremental generating capacity over peak load is called the margin. Margin requirements for power plants arise from unscheduled outages. These unscheduled outages are separate from outages for scheduled maintenance and seasonal deratings of power plants. In addition to mechanical outages, solar power plants incur insolation outages. Consequently, when solar thermal conversion solar power plants are integrated with conventional nuclear and fossil power plants in a total power grid, a margin analysis must be performed to ensure

that the integrated system provides equally reliable electric service. If, because of this criterion, a solar plant requires the construction of conventional backup generating capacity, this standby capacity must be taken into account when making a comparative economic evaluation.

Having parametrically determined the technical performance of solar power plants for different modes of operation, a comparative economic evaluation of these alternative power plant concepts and conventional power plants can be made. The technical and economic results in this report are based upon preliminary descriptions of a single solar power plant concept. These results serve primarily to illustrate the potential capabilities of the methodology itself. As technical and economic characteristics of alternative solar thermal conversion systems become better defined from systems analyses conducted by the National Science Foundation, applications of the mission analysis methodology will become more significant.

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1. INTRODUCTION

The issues and methodology of the mission analysis are shown schematically in Figure 1-1. A systems analysis typically involves the balancing of incoming insolation with a demand load. Much of the effect is directed at selecting the proper subsystems such as collectors, storage, and conversion units. When the insolation energy is insufficient to meet the demand, it is assumed that energy can be drawn from conventional power sources to make up the difference.

In contrast with the typical systems analysis, the mission analysis evaluates one or several solar power plants integrated in a power grid with a number of conventional power plants to supply the aggregate demand in a particular service area. The mission analysis concerns itself with the interaction of these various systems, particularly with the constraints and mode of operation that may be imposed upon the solar plants by the integrated system.

An example of such an interaction is derived from the reliability requirements imposed by all major utility systems. Besides the repetitive daily and seasonal variations in the insolation, there are also periods of poor weather with little or no insolation. This situation can be considered the equivalent of a forced outage for a conventional plant and can be compensated for in solar plants by providing a large energy storage subsystem. Unfortunately, energy storage is costly and may be impractical in some situations. In this case, the forced outage rate of the solar plant might be larger than for a similar conventional plant. The utility would then have to increase the generating capacity margin to provide the same degree of reliability. Margin is the excess of the generating capacity over the peak demand. The ability of a solar plant to displace a conventional plant while maintaining equal

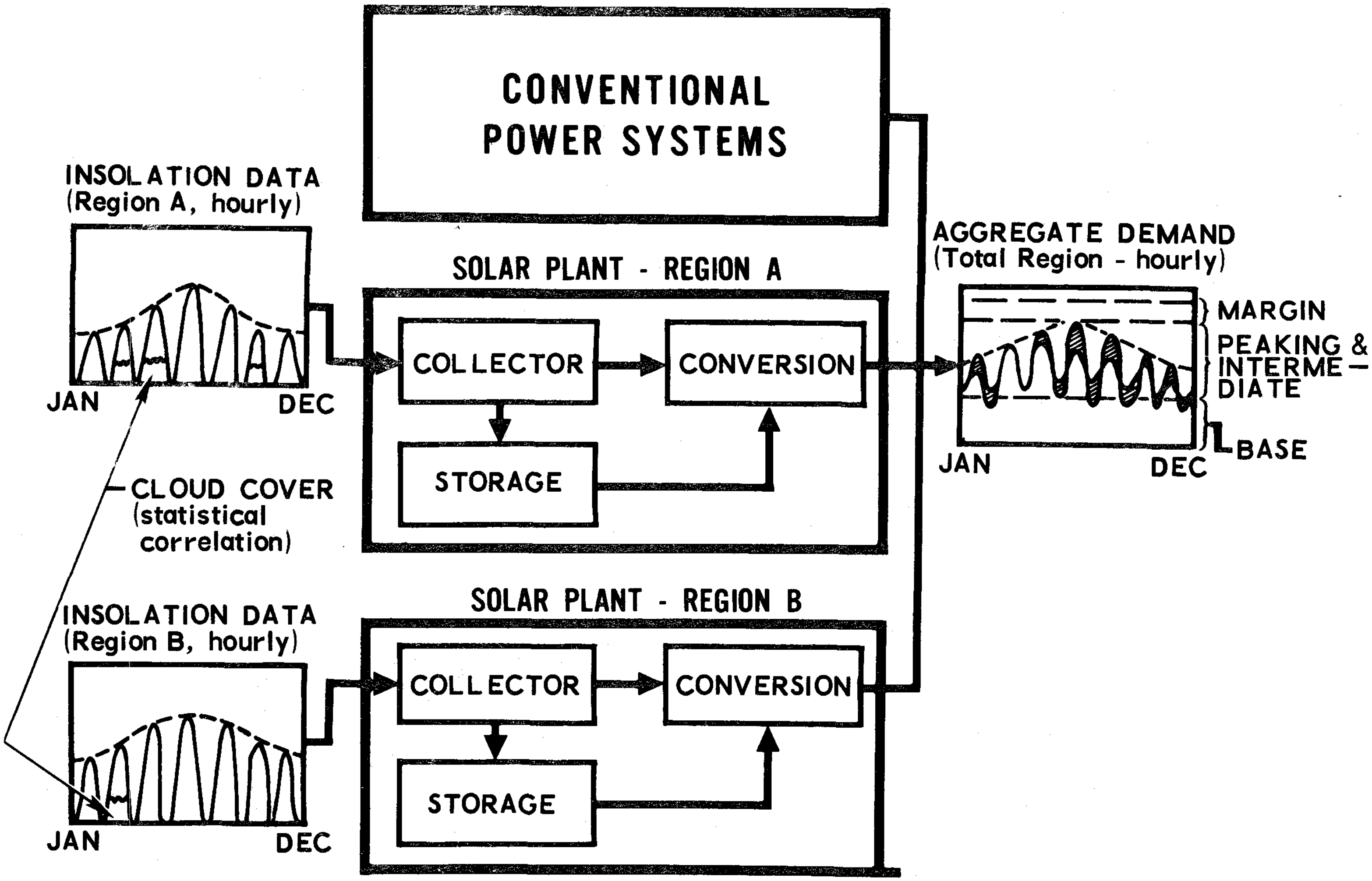


Figure 1-1. Mission Methodology - Integrated Solar and Conventional Power Grid

reliability for the total utility system is the "capacity displacement."

Once a utility has built a solar plant, it is reasonable that it would be operated whenever possible. This is because the fuel is essentially free and the solar plant would probably have the minimum incremental or marginal cost. This would result in a saving of the conventional plant fuels or "energy displacement."

If the capacity displacement of a solar plant is found to be low due to weather outages, it is possible that two or more plants, placed at different sites and of equivalent total size, would be preferred. This result depends on the statistical independence of insolation outages for the various solar plant sites.

Another correlation of interest is that occurring between the insolation and the demand. If there is a correlation between periods of poor insolation and reduced demand, as appears to be the case in California during the summer, then insolation reductions would be less important.

The tradeoff between thermal storage and collector size, and the impact on margin requirements, can be determined by system simulation. For this detailed simulation, hourly data for both insolation and demand must be determined. The hourly demand data must be for the 1980 to 2000 time period, which requires an hourly forecasting model for this time period. Both total and direct normal incidence hourly insolation data are required for the several regions identified in California. The geographically dispersed power plant and insolation demand correlations are important for the margin analysis. The dynamic interaction between insolation, the solar power plant within the total system grid, and the aggregate demand will determine the technical, operational, and economic characteristics for comparative evaluation of alternative solar thermal conversion systems with conventional power plants. Based upon these results, technical and economic requirements can be established for system, subsystem, and component design. Subsequently, the market capture potential of these preferred solar plants can be determined.

2. MISSION/SYSTEM ANALYSES

2.1 INTRODUCTION

This section describes the mission/system analyses performed to examine the dynamic interaction of insolation, demand, and solar power systems. These analyses utilized the hourly demand projections and regional insolation data described in Volumes II and III. A methodology was developed to parametrically assess the performance characteristics of alternative solar thermal conversion missions and systems in realistic operating environments on a consistent basis. Based on the mission/system analysis results, an economic analysis was performed to assess the potential role or mission of alternative solar thermal conversion systems.

2.2 SYSTEM MODELING

One of the objectives of the mission/system analysis is to examine the interaction of the cyclically varying insolation, demand, and the implications of this interaction relative to solar power system characteristics. The solar power plants must be evaluated in a realistic operating environment by simulating the solar plant performance as part of an integrated total power system.

For compatible subsystem combinations, alternative operational modes to provide base load, intermediate, peaking, or load-following power were examined to determine the preferred mission applications of solar power plants.

For alternative solar power plants, with parametrically varied collector area, storage capacity and different modes of operation, the energy displacement and solar plant outage rates were determined. The solar plant outage rate determines the capacity displacement of these solar plants which, when combined with the energy displacement, permits the economic assessment of the alternative mission/systems applications. Furthermore, this methodology is generally applicable to a wide variety of solar plant system concepts and provides a basis for consistent system concept evaluation.

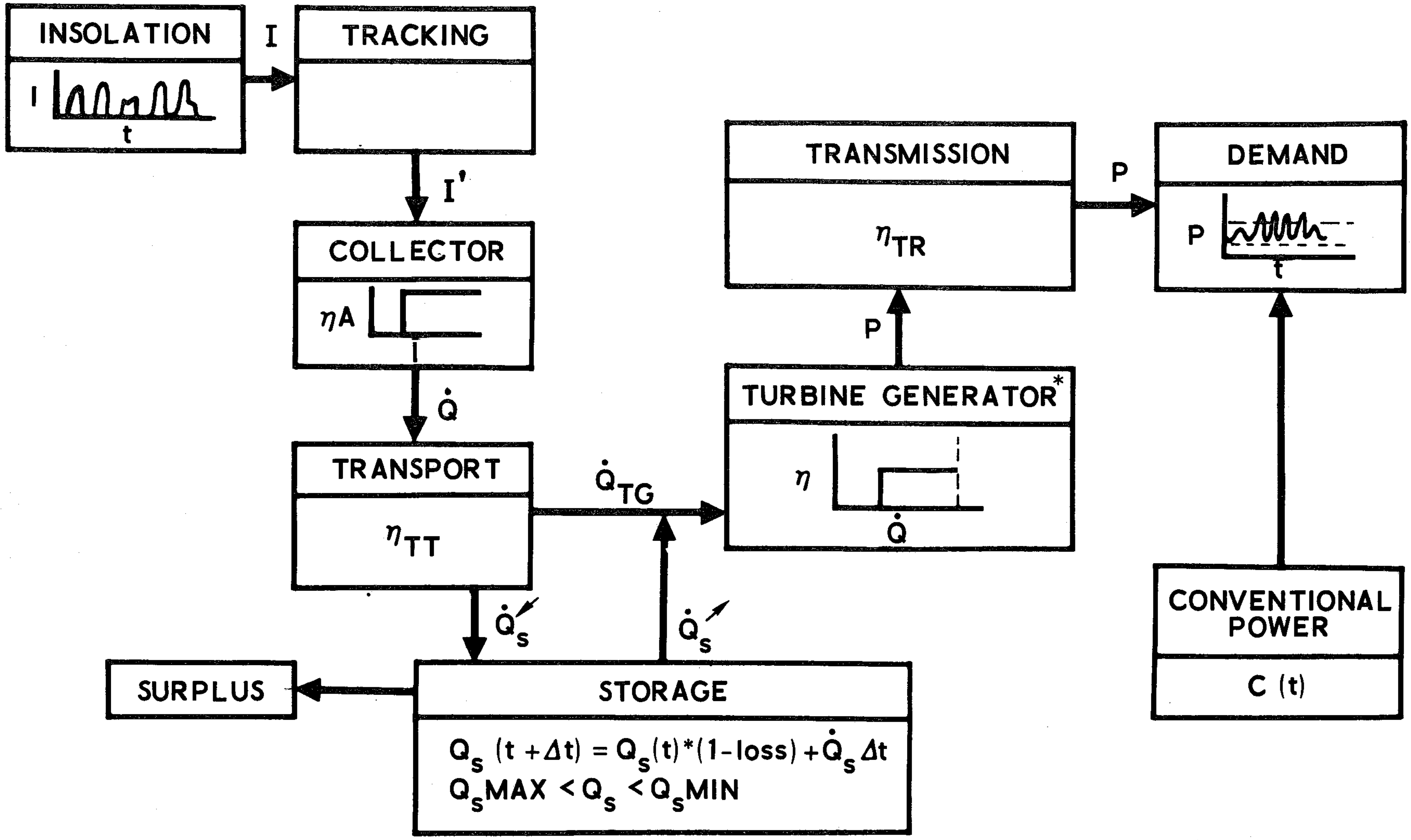
The approach used was to first develop a simple systems model with modular subsystem routines and, secondly, to improve the model by increasing the complexity of the subroutines in an evolutionary fashion. Consequently, the capability of evaluating the effect and sensitivity of important system parameters, such as system temperature, waste heat management, etc., can be incorporated.

2.3 SYSTEM METHODOLOGY

A block diagram of the simple system model is shown in Figure 2-1. This model consists of modular subsystem routines to facilitate substitution of more complex subroutines as these evolve. The insolation subroutines are the hourly total and normal incidence insolation data described in Volume III. These data are representative of the various climatological subregions of Southern California.

Since total insolation is measured on a horizontal plane, and normal incidence radiation is measured normal to the direction of the sun, the tracking model applies the appropriate geometrical and tracking corrections for the alternative collector configurations analyzed. Included in this subroutine is the sky brightness model which will be subsequently described. The tracking model will therefore compute the insolation energy which can potentially be collected.

The collector subsystem for a particular design and operating temperature was represented by its collector area and thermal efficiency. Provision is made for incorporation of a threshold insolation level, below which the collector does not operate. Similarly, the energy transport subsystem, for



*Turbogenerator

Figure 2-1. Simple System Block Diagram

a given operating temperature, is simply represented by its efficiency. The thermal energy can be utilized directly by the turbine generators, or stored for future utilization, depending on the power demand and generator rating.

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

The turbine generator subroutine converts input thermal energy into electrical energy with a conversion efficiency. This efficiency is, of course, a function of operating temperatures exhaust back pressure, etc. The turbine-generator model incorporates a maximum design (name plate) rating, as well as a minimum level of operation.

The electrical energy generated, when transmitted and combined with the conventional systems power output, is matched to meet the aggregate electrical base, intermediate, and peaking hourly demand load for any given year as forecasted by the demand methodology discussed in Volume II.

This model permits the simulation of one or more solar power plants that are integrated into a power grid on an hour-by-hour basis for at least a full year. The following detailed description of some of the major subroutines of the system simulation model provides additional insight into the present capabilities of this methodology. As the various NSF-contracted system analyses progress, these subsystem descriptions will be expanded in an evolutionary fashion to incorporate the effects of major system parameters. Rather than duplicating the system analysis efforts of other contractors, the increase in complexity will only be to the extent necessary to assess the effects and sensitivity of major system parameters on overall system performance and economics.

2.3.1 Insolation Data Input

An hourly insolation data base was formulated for nine regions, eight in Southern California and one for Albuquerque, New Mexico. These data are available for use in system simulation and mission analyses. The data base is stored on computer-compatible magnetic tape and contains hourly insolation data for a two-year time period.

The contents of the data base can be summarized in three categories:

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

In contrast to the insolation data, the available weather information is incomplete and no effort has been made to fill in the missing data.

The insolation data for the Inyokern, California and Albuquerque, New Mexico stations have been designated by the National Science Foundation as the standard insolation data base for use by all Solar Thermal Conversion System contractors. The use of these data by all contractors in at least one of their performance calculations will greatly facilitate the consistent evaluation of alternative system concepts.

In order to proceed with mission/system analyses, some basic information about the collecting devices is required. Two quantities of particular interest are the incident insolation available for the collecting device and the efficiency with which the device is going to convert this energy to the remainder of the solar conversion plant.

2.3.2 Tracking Subroutine

In order to realistically represent the insolation input for a solar collector as a function of time and site, an appropriate geometry model was developed. The model describes the relative orientation of the collector aperture with respect to the sun as well as with respect to the horizon.

The inclusion in the study of diffuse as well as direct insolation is required, not only because of the effective usage of diffuse insolation by flat plate type collecting devices but also in that diffuse insolation effectively subtracts from the total direct component which primarily effects concentrator type systems.

Diffuse insolation may be further subdivided into an istropic and an anisotropic contribution. A sky brightness distribution model was included in this subroutine to account for these contributions. The mathematical formulation adopted for the contribution to the incident insolation from an incremental area of the sky is:

$$dI = A\,(\Delta\theta) + Be^{-k\theta^2} + C \qquad (2\text{-}1)$$

where
- A = direct insolation coefficient
- B = anisotropic insolation coefficient
- C = isotropic insolation coefficient
- k = coefficient denoting rate of decrease of anisotropic insolation as θ increases
- θ = angle between earth-sun line and an incremental area of the sky
- $\Delta\theta = 1$ for $\theta \leqslant 16'$
- $\Delta\theta = 0$ for $\theta > 16'$.

The coefficients A, B, C, and k are all functions of time. The coordinate system is depicted in Figure 2-2.

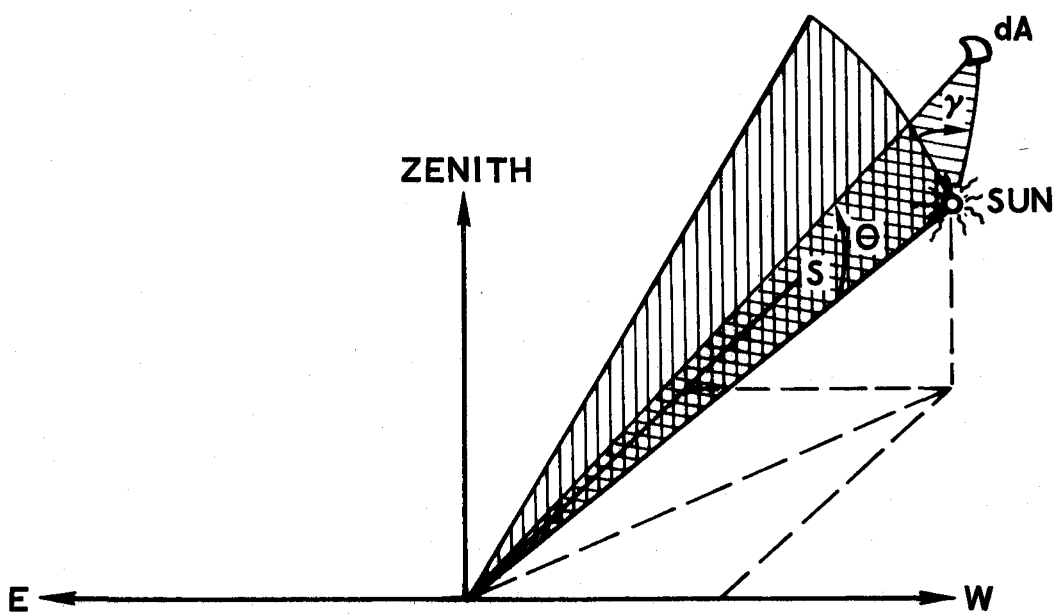


Figure 2-2. Basic Coordinate System Used in the Tracking Model

In the tracking subroutine of the system analysis model, all three terms in the mathematical formulation were included. These three terms contain five coefficients, all of which depend on atmospheric conditions. Only two routinely measured insolation values are included in the data base:

- The normal incidence insolation, which is the integral over the 3° field of view of the pyrheliometer;

- The total insolation which is the integral over the entire hemisphere with an appropriate weighting factor to account for the horizontal orientation of the receiver.

Since it is not possible to determine five coefficients from two measurements, estimates of at least some of the coefficients are required. Initially it was hoped that a literature search would provide some independent measurements of the sky brightness distribution which could be used to determine the additional parameters. However, very few measurements are made of the way in which the sky brightness falls off near the solar rim. Such measurements are difficult because of the discontinuity at the edge of the solar disk. All of the measurements found were made under clear sky conditions. For the present study, information was needed under a variety of sky conditions, and consequently, this is an area which needs additional measurements.

Since such measurements were unavailable for the mission analysis performed under this contract, the B coefficient in the formulation was set to zero and the A and C coefficients were adjusted to agree with the data base values for normal incidence and total insolation.

The quantity dI may be expressed in kilowatts/meter^2 steradian. Therefore the total incident insolation is obtained by integrating over the portion of the sky which the aperture "sees." The boundaries of that portion of the sky which is "seen" by the aperture consist of the plane defined by the plane of the aperture and the horizon. The boundary that is utilized is that which indicates the smaller limit of integration over θ. The second variable of integration is the azimuthal angle γ. This angle is measured in the plane perpendicular to the earth-sun line. The integration:

$$\text{I (total incident)} = \iint dI(\theta)\ d\theta d\gamma$$

$$= \int_0^{2\pi} \left[\int_{\theta_1(\gamma)}^{\theta_2(\gamma)} dI(\theta)\ d\theta \right] d\gamma \qquad (2\text{-}2)$$

may be represented numerically as:

$$\text{I (total incident)} = \sum_{\gamma=0}^{\gamma=2\pi} \sum_{\theta_i=0}^{\theta_i=\theta_{limit}(\gamma)} [dI(\theta_i)]\ \Delta\theta\ \Delta\gamma$$

The great majority of solar collector configurations (i. e., parabolic trough, flat plate) consist of those which are east-west oriented and possibly track in the north-south direction. The tracking model presently accommodates these types of systems. The tilt φ of the collector aperture from the vertical may either be fixed or the optimum tilt determined for the particular location of the sun so as to optimize the amount of direct incident insolation. The additional option of a variable azimuth for the collecting aperture will be included in future studies (i. e., central receiver concept).

The optimum tilt (for an east-west oriented collector) may be expressed in terms of the azimuth (α) and altitude (β) of the sun:

$$\varphi\ \text{(Optimum)} = \frac{\tan\beta}{\cos\alpha} \qquad (2\text{-}3)$$

The limits of integration for θ are functions of γ as well as the azimuth and altitude of the sun and the tilt from the vertical of the collecting aperture. The determination of these limits involves a complex manipulation of trigonometric functions describing the solid geometry of the various limiting planes and the orientation of the sun. The equations leading to these limits are contained in Appendix A of this volume.

2.3.3 Solar Collector Subroutine

After appropriate geometrical tracking transformations have been performed, the program models the operation of the solar collector by relating the solar insolation input to the collector and the working fluid heat flow output. Parameters affecting collector performance are the collector area, reflectivity, emissivity, absorptivity, working fluid temperature, and re-radiation losses, among others. An overall collector efficiency η_c taking into account the combined effect of these parameters is used to approximate the collector performance such that the total heat flow output from the collector $\dot{Q}$ is:

$$\dot{Q} = \eta_c \, A_c \, I' \qquad (2\text{-}4)$$

Within the collector module a lower limit of insolation is introduced to account for the fact that the collector will not function when the solar insolation is less than some specific input value. In other words, this constraint results in a zero output when the insolation is too low for the collector to operate.

2.3.4 Energy Transport Subroutine

The heat flow output from the collector is transported directly to the turbine-generator or to a thermal storage unit, or to both simultaneously in some instances. In the thermal transport process losses are incurred. These losses are modeled by the transport module in the program in an overall loss or efficiency factor of thermal transport (η_{TT}). The value of η_{TT} can be related to such factors as the distance traveled by the working fluid, the size and insulation of the pipes, and the temperature of the working fluid.

After the heat flow has been reduced by the thermal transport efficiency (η_{TT}), the thermal energy is either input directly to the turbine-generator,* thermal storage, or both. The criteria governing the disposition of the thermal energy output from the collector are as follows:

- If an electric demand is present which is greater than the minimum operating level of the turbine-generator (G_{min}) all thermal energy available from the collector is sent to the turbine-generator.
- If the demand is less than G_{min}, all thermal energy available from the collector is deposited in storage.
- If the thermal energy available from the collector is less than the amount required to operate the turbine-generator at G_{min}, it is deposited in storage.
- If the thermal energy available is greater than that required to meet the demand, the excess energy is deposited in storage.

2.3.5 Thermal Energy Storage Subroutine

The thermal storage unit is treated as a separate subroutine in the system model. The storage unit has been modeled to have the following characteristics and to operate in accordance with the following criteria:

- The thermal storage unit can accept thermal energy from the collector.
- The storage unit has a maximum heat capacity specified in terms of the number of hours (N) of the turbine-generator operation at its rated capacity (G_{max}).
- The storage unit loses thermal energy to its surroundings at a rate (α) proportional to the amount of energy in storage.

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* Also turbo-generator.

- The storage unit can supply thermal energy to the turbine-generator at a rate sufficient for operation at its maximum rated capacity (G_{max}).
- If a minimum value of thermal energy in storage (β) is reached, the storage unit will not supply further energy to the turbine-generator.
- The storage unit will supply thermal energy to the turbine-generator when the demand exceeds the collector thermal output.
- If the thermal storage is full and the generator is meeting the demand, any excess thermal energy over the turbine-generator demand supplied by the collector is dumped as surplus heat.

The capacity of a thermal storage unit to operate a turbine-generator for a specified number of hours is determined as follows:

Since:

$$HIS_t = HIS_{t-1}\,(1-\alpha) - G_{in} \qquad (2\text{-}5)$$

therefore:

$$HIS_N = HIS_o\,(1-\alpha)^N - G_{in}\left[\frac{1-(1-\alpha)^N}{\alpha}\right] \qquad (2\text{-}6)$$

if:

$$HIS_N = \beta\, HIS_o \qquad (2\text{-}7)$$

then:

$$HIS_o = G_{in}\left[\frac{1-(1-\alpha)^N}{\alpha\left[(1-\alpha)^N-\beta\right]}\right] \qquad (2\text{-}8)$$

where:

N	=	thermal storage in number of hours of turbine-generator operation at maximum capacity
G_{max}	=	maximum rated capacity of generator, (KW_e)

G_{in}	=	thermal power input to the turbine-generator required for operation at maximum rated capacity, (KW_t)
HIS_o	=	maximum capacity of the thermal energy storage unit, (Kwh_t)
HIS_t	=	thermal energy in storage at a given time (t), (Kwh_t)
α	=	rate of thermal energy loss from storage (Kwh/hr)
β	=	minimum level of thermal energy in storage, expressed as a percent of the maximum storage capacity.

2.3.6 Turbine-Generator Subroutine

For a given turbine inlet temperature, condenser temperature and pressure, and number of reheats, the power output of the turbine-generator (at rated capacity) is related to the thermal power input as follows:

$$G_{out} = \eta_{TG} \; G_{in} \tag{2-9}$$

2.3.7 Demand Requirements

The electrical power demand is the hourly forecast as determined by the demand analysis (Volume II). This total utility system demand is supplied by the combination of solar and conventional power plants. The solar power plants can be programmed to operate in either base, intermediate, or peaking power modes.

2.3.8 Program Inputs and Outputs

The basic inputs to the program are:

1. Hourly insolation data
2. Collector concept and orientation
3. Collector tracking parameters

4. Collector area
5. Collector efficiency
6. Thermal transport efficiency
7. Maximum and minimum thermal storage capacity
8. Thermal storage loss rate
9. Maximum and minimum turbine-generator operation levels
10. Turbine-generator efficiency
11. Electric power transmission losses
12. Hourly demand data.

The output of the program as a function of time is:

1. Insolation energy into the collector and thermal energy output from the collector
2. Thermal power sent directly to the turbine-generator
3. Thermal power to storage
4. Thermal energy in storage
5. Thermal power from storage to the turbine-generator
6. Solar electric power output from the turbine-generator
7. Electric demand
8. Conventional electric power assist
9. Integrated solar electric energy output over the entire period of simulation (e.g., a full year)
10. Integrated conventional assist electric energy required over the period of simulation
11. Percent of time solar electric power meets specified percentage of electric demand (solar power plant outage frequency distribution).

2.3.9 Computer Program

The computer program incorporates all of the system modular subroutines discussed above. This program has been tested to parametrically determine the importance of a variety of system parameters and operating modes. The results of these illustrative simulations are summarized in the following section.

2.4 SYSTEM ANALYSIS

Typical examples of the solar thermal electric generating system simulations are included here based on a projected system demand that corresponds to the Southern California Edison Company service territory in the year 1990.

The range of collector areas and thermal storage times considered in the systems simulation example are shown in Table 2.1 for each of these demand ranges. The collector areas range between 5 and 40 square kilometers and the storage ranges between 0 and 18 hours depending upon the application.

2.4.1 Electric Power Demand

Figure 2-3 shows the electric power demand used for system simulation. For illustration, only the first weeks in April, August, and December are shown. This demand is a projected hourly electrical load for the Southern California Edison Company territory during the year 1990 with a peak demand of 32,000 MWe.

The potential capacity displacement for different modes of operation for solar power plants was examined by selecting the various operating ranges shown in Figure 2-3:

Table 2.1. Solar Thermal Conversion Systems Simulation

BASE LOAD SOLAR PLANT	
• DEMAND RANGE	0 - 1000 mWe
• COLLECTOR AREAS	10 - 40 KM^2 (3.86 - 15.44 MI^2)
• THERMAL STORAGE	0 - 18 HRS
INTERMEDIATE SOLAR PLANT	
• DEMAND RANGE	20,000 - 21,000 mWe
• COLLECTOR AREAS	10 - 25 KM^2 (3.86 - 9.65 MI^2)
• THERMAL STORAGE	3 - 12 HRS
PEAKING SOLAR PLANT	
• DEMAND RANGE	25,500 - 26,500 mWe
• COLLECTOR AREA	5 - 15 KM^2 (1.93 - 5.79 MI^2)
• THERMAL STORAGE	0 - 6 HRS

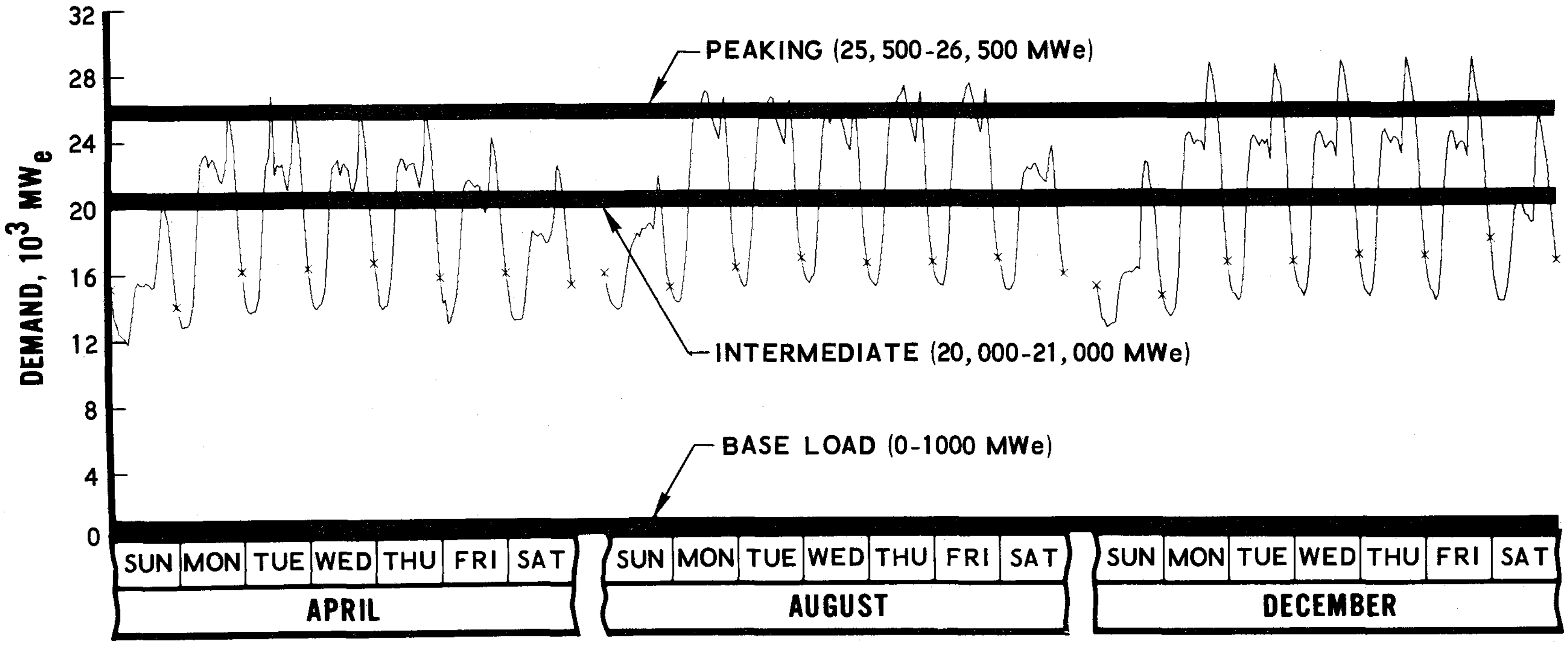


Figure 2-3. Electric Power Demand 1990
Southern California Edison Company

- Base-load between 0 and 1000 MWe.
- Intermediate-load between 20,000 and 21,000 MWe.
- Peaking load between 25,500 and 26,500 MWe.

The 0-1000 MWe demand range was selected for base power applications of solar plants because, once the capital investment is made, the marginal cost of solar power plants is lower than for conventional nuclear or fossil base load power plants.

As can be seen, the peaking range does not intersect many peaks in the beginning of the year, which indicates an ideal period for scheduled maintenance.

A solar power plant might reasonably be expected to operate at times when the electrical demand does not fall in one of the intermediate or peaking bands indicated. For purposes of determining the capacity displacement of a solar plant operating in a particular mode, operation outside these bands was permitted only when storage was full and turbine-generator capacity was available. However, operation outside these bands contributed only to energy (fuel) displacement in the economic evaluations which are described in later sections of this report. (Sections 2.4.8 and 2.4.10)

The aforementioned demand ranges for solar power plant application to provide base load, intermediate, and peaking power are summarized in Table 2.1.

In addition, the collector areas and thermal storage were varied parametrically in the systems simulation to determine the technical performance of various combinations of these parameters. The system combination with the lowest electrical cost was determined by means of economic and financial evaluation of the energy and capacity-displacement potential for each mode of operation of the solar plants, as determined by system simulation.

2.4.3 Solar Thermal Conversion Plant Characteristics

Having developed the systems models, these methodologies were tested by selecting a set of solar plant design parameters summarized in Table 2.2, representative of the parabolic cylindrical type of concentrator design. These concentrating collectors have an east-west orientation with north-south diurnal tracking and a combined collector/thermal transport efficiency of 45 percent. Thermal storage is assumed to have aheat loss of 2 percent per hour. The turbo-generator was rated at 1000 MWe, with a minimum operating level of 100 MWe, and a conversion efficiency of 30 percent.

The illustrative 1000 MWe solar power plant was assumed to be located in Yuma, Arizona; consequently, the normal incidence insolation developed for this station was used for simulation. Hourly simulations were made for the entire year 1990 using the Southern California Edison Company territory hourly demand forecast shown in Figure 2-3.

These assumed solar plant design characteristics are only representative and were selected to illustrate the capabilities of the methodology developed. Actual system design data will be used when these become available.

2.4.4 Normal Incidence and Collector Insolation

Figure 2-4 shows the relationship between the normal incidence insolation, as measured by a pyrheliometer, and the insolation which is potentially available for a parabolic cylinder-trough type of concentrating collector with an east-west orientation and north-south diurnal tracking.

The data shown are only for the first week in April at Yuma, Arizona. The outer envelope is the normal incidence insolation, and the inner envelope is the available insolation after correction for geometry and sky brightness. The geometric cosine effect for the parabolic cylindrical type of concentrator with the fixed east-west orientation is apparent in this figure.

Table 2.2. Solar Thermal Conversion Plant Charactersitics

CONCENTRATING COLLECTOR	
• E-W ORIENTATION; N-S DIURNAL TRACKING	
COLLECTOR/THERMAL TRANSPORT	
• EFFICIENCY (η_C)	45%
THERMAL STORAGE	
• HEAT LOSS	2%/HR
TURBO-GENERATOR	
• RATING	1000 mWe
• MINIMUM OPERATING LEVEL	100 mWe
• EFFICIENCY (η_{TG})	30%
LOCATION	YUMA, ARIZONA
TIME PERIOD	1990
DEMAND DATA	SOUTHERN CALIFORNIA EDISON CO.

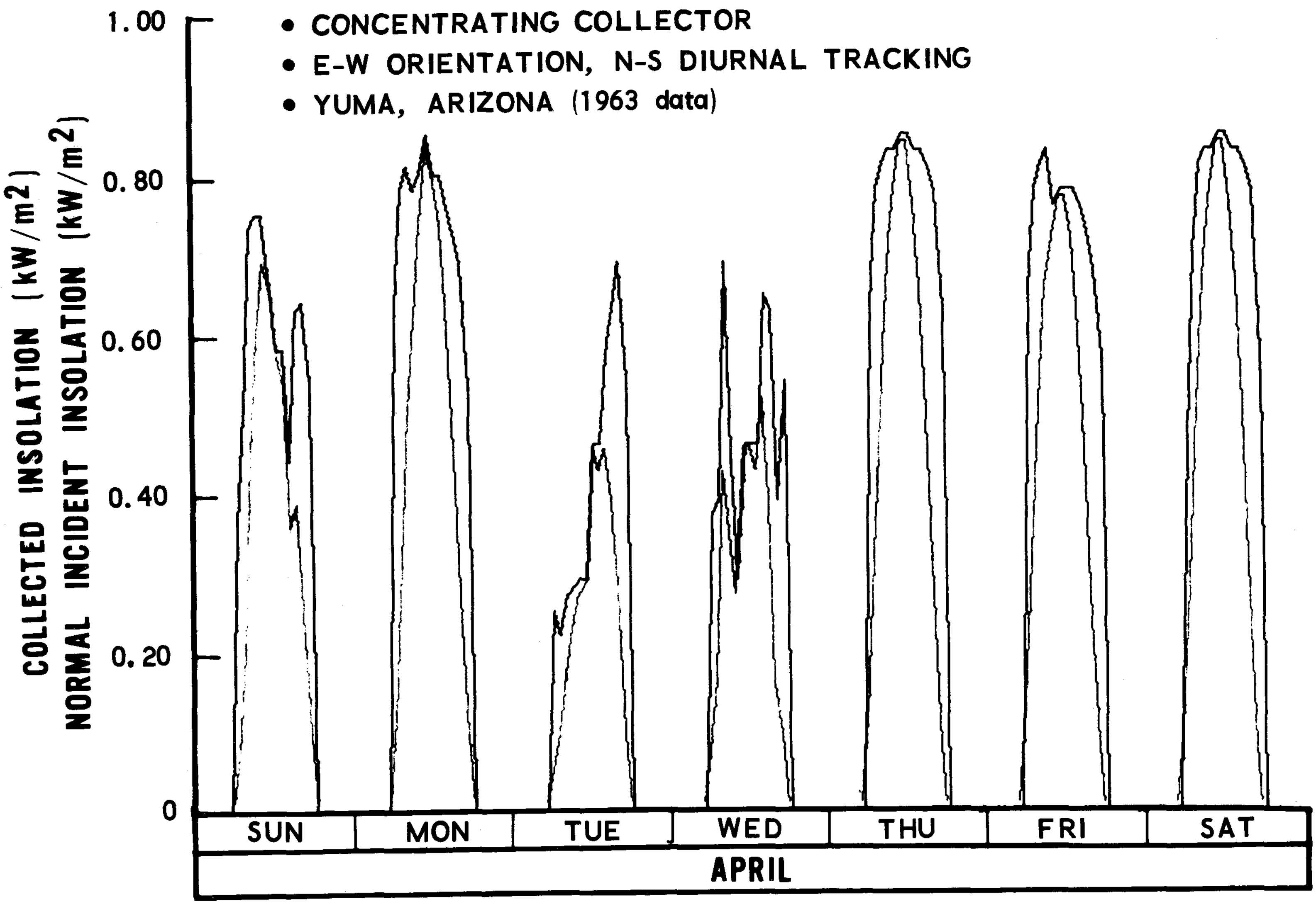


Figure 2-4. Normal Incidence and Collector Insolation

The available collector insolation energy, when integrated over the entire year, is 72 percent of the normal incidence insolation. Combining the above 72 percent with the 45 percent collector and 30 percent turbine-generator efficiencies results in an overall systems efficiency of approximately 9.7 percent for this hypothetical solar thermal conversion system.

2.4.5 Base Load Solar Plant - Operating Characteristics

Some of the results of actual simulation of a solar power plant with previously defined characteristics for base load application are shown in Figure 2-5. Even though the simulation was performed on an hourly basis for a full year (1990) and for many combinations of collector area and storage, this figure shows only the results for the first week in December and a single combination of collector area and storage capacity for illustrative purposes. These results are for a 1000 MWe generator rated solar power plant with a 30 Km^2 collector area, and a 12-hour storage capacity.

The top figure shows the relationship between the 1000 MWe base load electricaldemand (1000 MWe line), the power output of the turbo-generator to meet this demand (line between 0 and 1000 MWe), and the electrical equivalent insolation at the collector (sinusoidal-shaped curves). The electrical equivalent insolation is the actual normal incidence insolation, corrected for geometry, multiplied by the respective collector and turbo-generator efficiencies and the collector area.

The bottom figure shows the dynamics of storage in terms of power from the collector to storage (sinusoidal-shaped curves), power from storage to the turbo-generator (trapezoidal-shaped curves), and energy available in storage (triangular-shaped curves).

OPERATING CHARACTERISTICS

- CONCENTRATING COLLECTOR AREA ~ 30 km^2 (E-W orientation)
- THERMAL STORAGE ~12 hr
- YUMA, ARIZONA

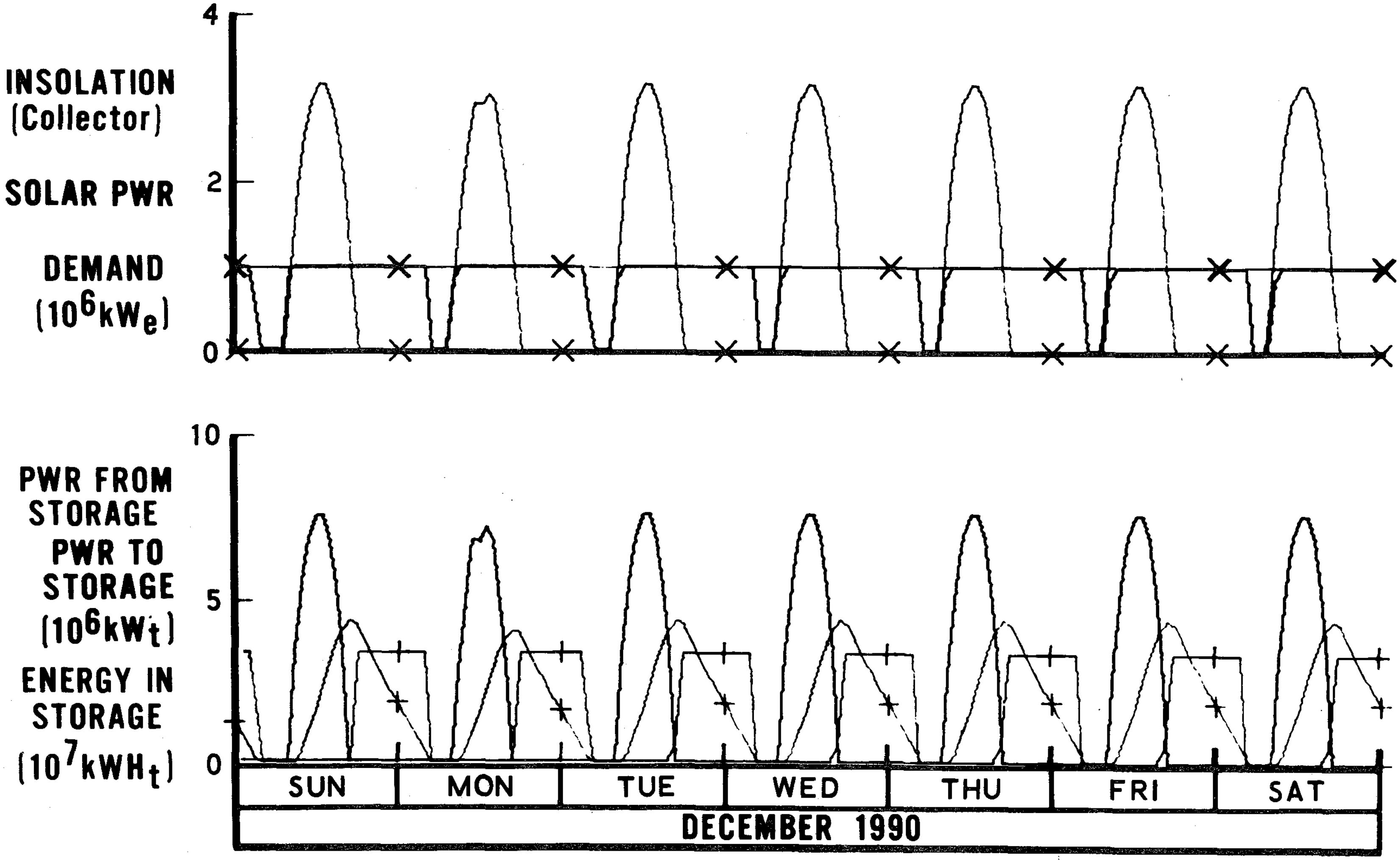


Figure 2-5. Base Load Solar Thermal Conversion Plant (1000 MWe) Operating Characteristics

As can be seen, power not used by the turbo-generator during sunshine hours flows to storage, thereby increasing the energy in storage. During nonsunshine hours, the turbo-generator draws power from storage to meet the demand and, consequently, reduces the energy in storage.

Each of the significant parameters is integrated over the full year of operation to provide a measure of the technical performance for the solar plant.

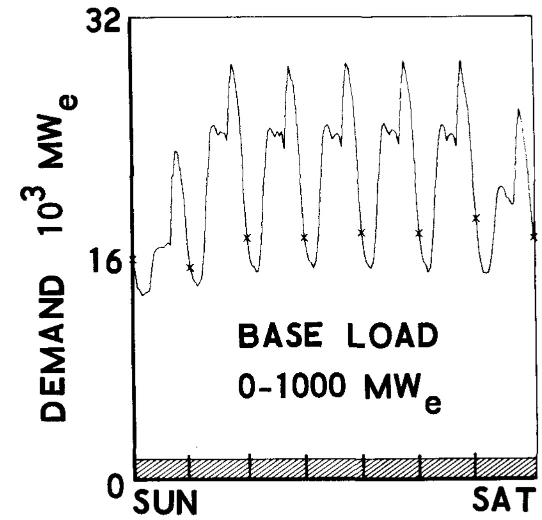
2.4.6 Base Load Solar Plant - Technical Performance

The preceding base-load (0-1000 MWe) system simulation was performed for many combinations of collector areas and storage capacities. The parametric performance results, based upon an hourly simulation for a full year for this base load application, are summarized in carpet plot format in Figure 2.6.

The solar capacity factor, plant capacity factor, and energy displacement are shown for different combinations of solar collector areas and storage capacities. The solar capacity factor is the actual integrated turbo-generator energy output divided by the maximum theoretical total capacity output. The plant capacity factor is 90 percent of the solar capacity factor, based on the assumption of a 5-week per year (10 percent) scheduled maintenance period. The energy displacement is the integrated turbo-generator output divided by the demand energy for the year 1990 (within the assumed band of operation). Since the base-load demand of 1000 MWe, continuous, is the same as the rated capacity of the plant, the energy displacement is the same as the solar capacity factor for base-load applications.

The energy displacement is a measure of how well a particular solar plant design meets the demand specified and, consequently, provides an estimate

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



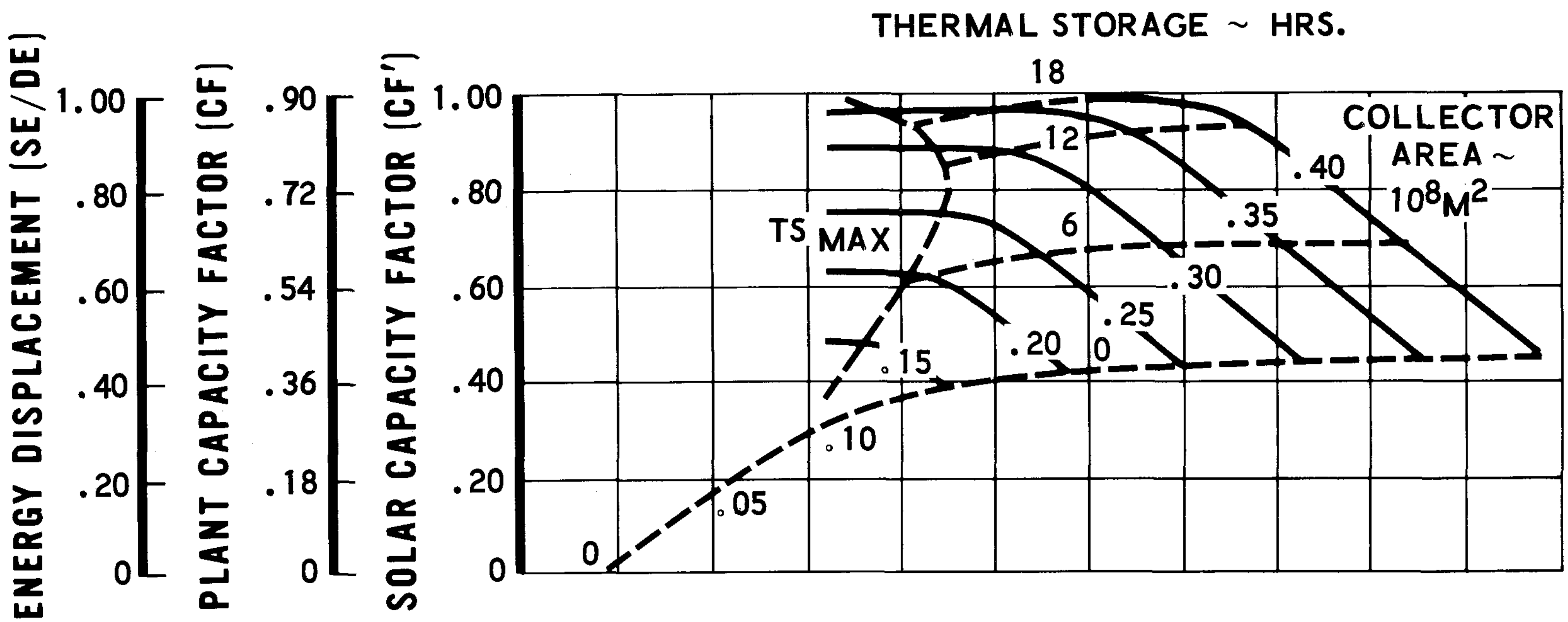


Figure 2-6. Base Load Solar Thermal Conversion Plant

of the solar power plant outage rate. The outage rate is necessary in computing the capacity displacement of solar power plants when placed in the total power system grid, as will be discussed in the margin analysis section. The plant capacity factor provides a measure of the actual useful electrical energy per year delivered by the solar power plant. The combination of this latter energy output and capacity displacement are important inputs to the economic evaluation of solar power plants, discussed in a following section.

As can be seen from Figure 2-6, for a particular collector area such as 25 Km^2, a significant improvement in base-load performance is attained by increasing storage capacity. However, this improvement has diminishing returns when more storage is added and finally, beyond 10 hours of storage, no further improvement in performance can be attained for this particular collector area of 25 Km^2. At this point, the collector area is too small to add additional energy to storage. This limit condition of maximum storage is shown in Figure 2-6 by the near-vertical dashed line. In this case, additional performance can only be attained by increasing the collector area, which permits additional useful storage capacity to be added.

A plant capacity factor of 80 percent for base load applications was attained by a solar plant with a collector area of 25 Km^2 and storage capacity of 12 hours, located at Yuma, Arizona. This case has an energy displacement of almost 90 percent (and an unscheduled outage of approximately 10 percent).

The relative merits of the various combinations of collector area and storage capacity are the subject of the economic and financial analysis in Section 4 of this volume.

2.4.7 Intermediate Load Solar Plant - Operating Characteristics

Figure 2-7 shows simulation results of the operating characteristics for the previously defined 1000 MWe rated solar power plant applied to the 20,000 to 21,000 MWe intermediate demand range. The simulation results are shown for the first week of April of the year 1990 for illustration purposes and reflect a plant with a collector area of 20 Km^2 and storage capacity of 6 hours.

The top figure shows the electrical equivalent insolation at the collector, demand, and solar plant turbo-generator output to meet this demand. As can be seen, the intermediate load demand is discontinuous, corresponding to intersections with the total demand profile between 20,000 and 21,000 MWe. As expected, the weekend demand is smaller than for week days.

The bottom figure displays the operating characteristics of the storage subsystem in terms of power from the collector to storage, power from storage to the turbo-generator, and energy available in storage.

2.4.8 Intermediate Load Solar Plant - Technical Performance

The parametric technical performance characteristics for intermediate load solar power plants, based upon a full year of hourly simulation, are shown in Figure 2-8.

For the 1000 MWe rated solar power plant, the collector area and storage capacity were varied in order to parametrically assess the technical performance for various combinations of these subsystems.

Shown in Figure 2-8 are the solar capacity factor, plant capacity factor, and energy displacement for various combinations of collector area and storage capacity, when operating within the 20,000 to 21,000 MWe intermediate demand range.

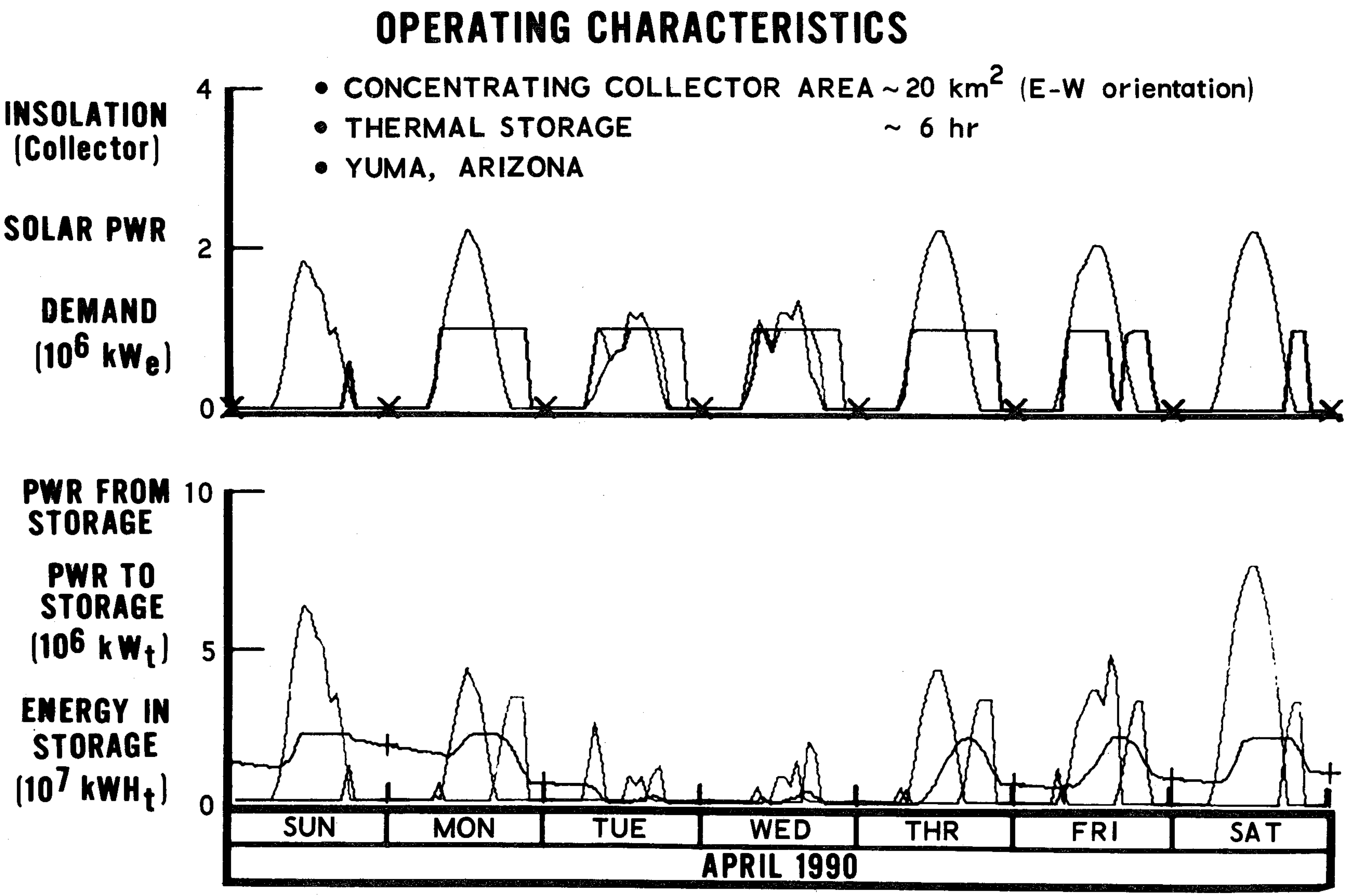
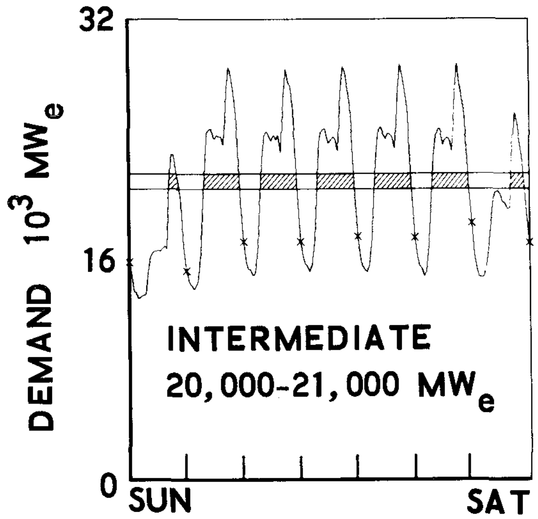


Figure 2-7. Intermediate Solar Thermal Conversion Plant (1000 MWe)

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



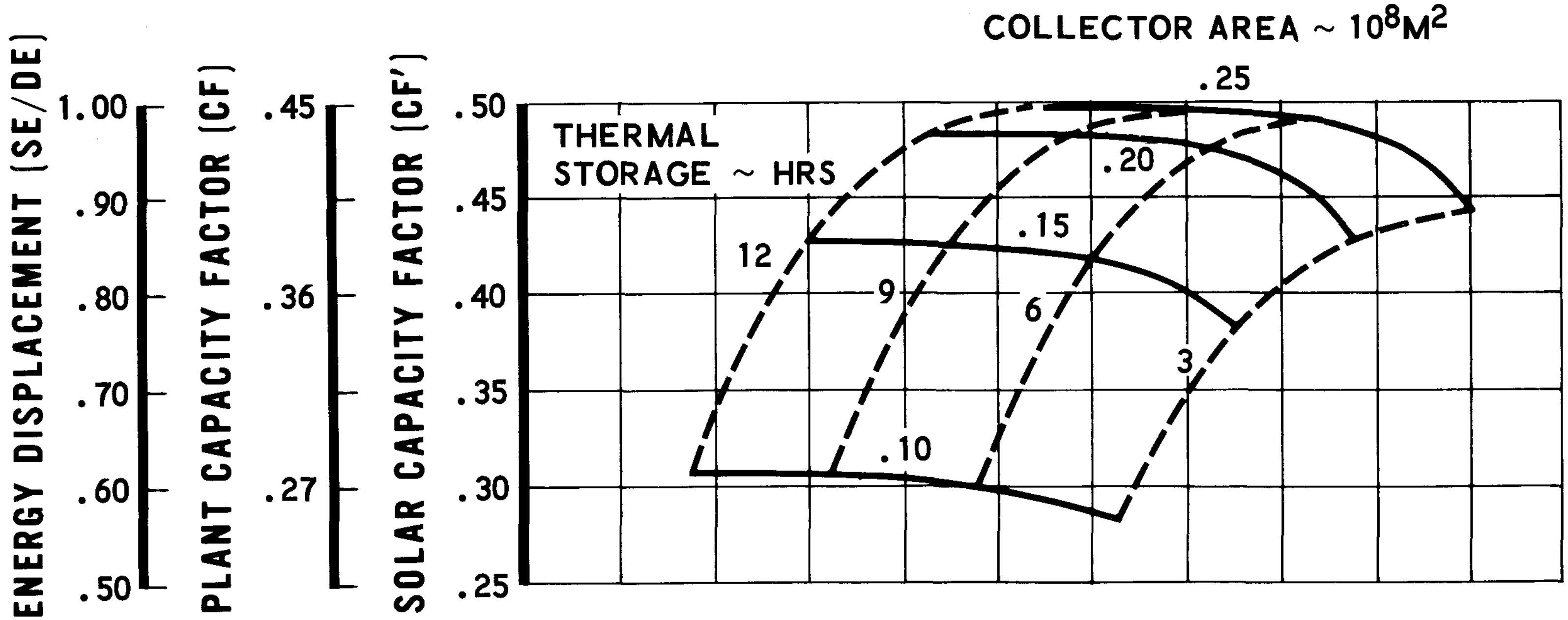


Figure 2-8. Intermediate Solar Thermal Conversion Power Plant

Again, the plant capacity factors were assumed to be 90 percent of the solar capacity factor, assuming a 5-week per year (10 percent) scheduled maintenance period.

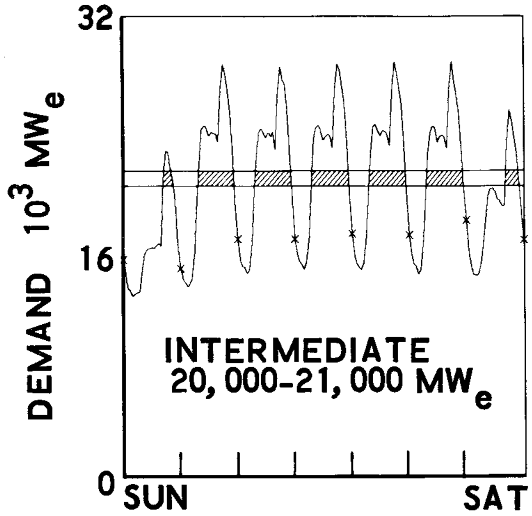
The energy displacement within the 20,000 to 21,000 MWe intermediate demand range is the integrated turbo-generator energy output divided by the integrated energy demand within the 20,000 to 21,000 MWe intermediate range, which is different from the solar capacity factor in this case (the solar capacity factor and energy displacement factor are identical for base load operations).

The energy displacement is a measure of the unscheduled outage characteristics in the 20,000 to 21,000 MWe demand range, which determines through the margin analysis the capacity displacement potential.

As can be seen from Figure 2-8, the storage requirement for intermediate-load solar plant applications are much smaller than for base-load operation.

In the intermediate demand applications for certain combinations of collector area and storage there may be situations where solar plant power is available and storage is full during periods of low or zero demand within the 20,000 to 21,000 MWe range. Because of the low marginal cost of solar energy, (because of zero fuel cost), once the solar plant has been built it was assumed to continue operating, displacing energy in the base-load region; however, no capacity displacement was assumed for this base-load energy displacement. This additional energy displacement and associated incremental capacity factor in the base-load region is shown in Figure 2-9 for the various combinations of collector area and storage capacity analyzed. The electrical and thermal base-load energy displacement shown on this Figure are related by the turbo-generator efficiency.

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



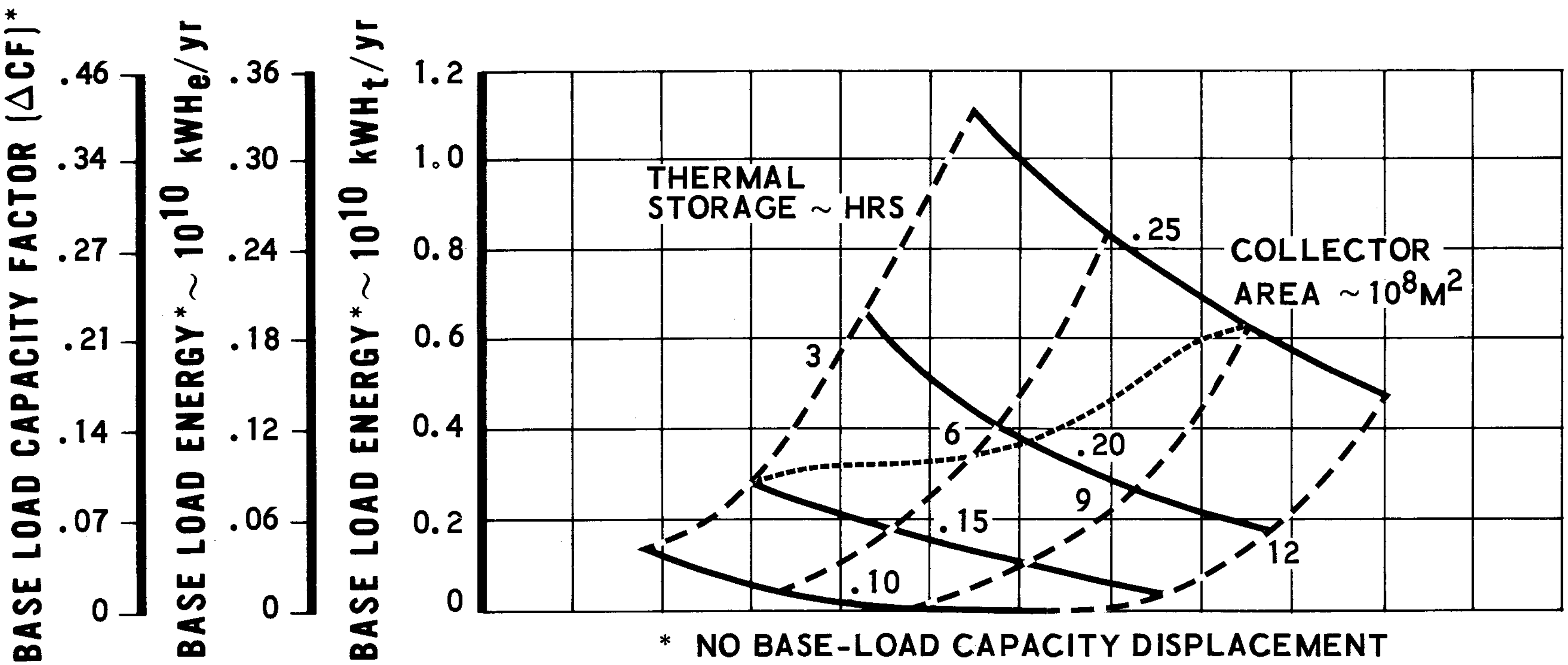


Figure 2-9. Intermediate Solar Thermal Conversion Power Plant, Energy Displacement and Incremental Capacity Factors

For certain combinations of large collector areas and small storage capacity, the turbo-generator with a rating of 1000 MWe cannot handle all the insolation energy available; consequently, this energy was assumed to be lost. These combinations of collector area and storage capacity are shown in Figure 2-9 above the dottle line, which represents the maximum base-load energy displacement available for these cases.

In the economic assessment of the intermediate-range solar power plants, credit was taken for the displaced conventional base-load fuel only, since no capacity displacement in the base load region was assumed.

2.4.9 Peaking Load Solar Power Plant - Operating Characteristics

The simulation results of the operating characteristics of a solar power plant, with previously defined characteristics, when applied to the 25,500 to 26,500 MWe peaking demand range, are shown in Figure 2-10. The results show for illustrative purposes are only for the first week of December of the year 1990, and reflect a 1000 MWe solar plant with a collector area of 10 Km^2 and storage capacity of three hours.

The top figure shows the electrical equivalent insolation at the collector, demand within the 25,500 to 26,500 MW band and solar plant turbo-generator output supplying this demand. As expected, the energy demand in the peak load range between 25,500 and 26,500 MWe is smaller than for the intermediate case, and is only present during week days.

The bottom figure displays the operating characteristics of the storage subsystems in terms of power from the collector to storage, power from storage to the turbo-generator, and energy available in storage.

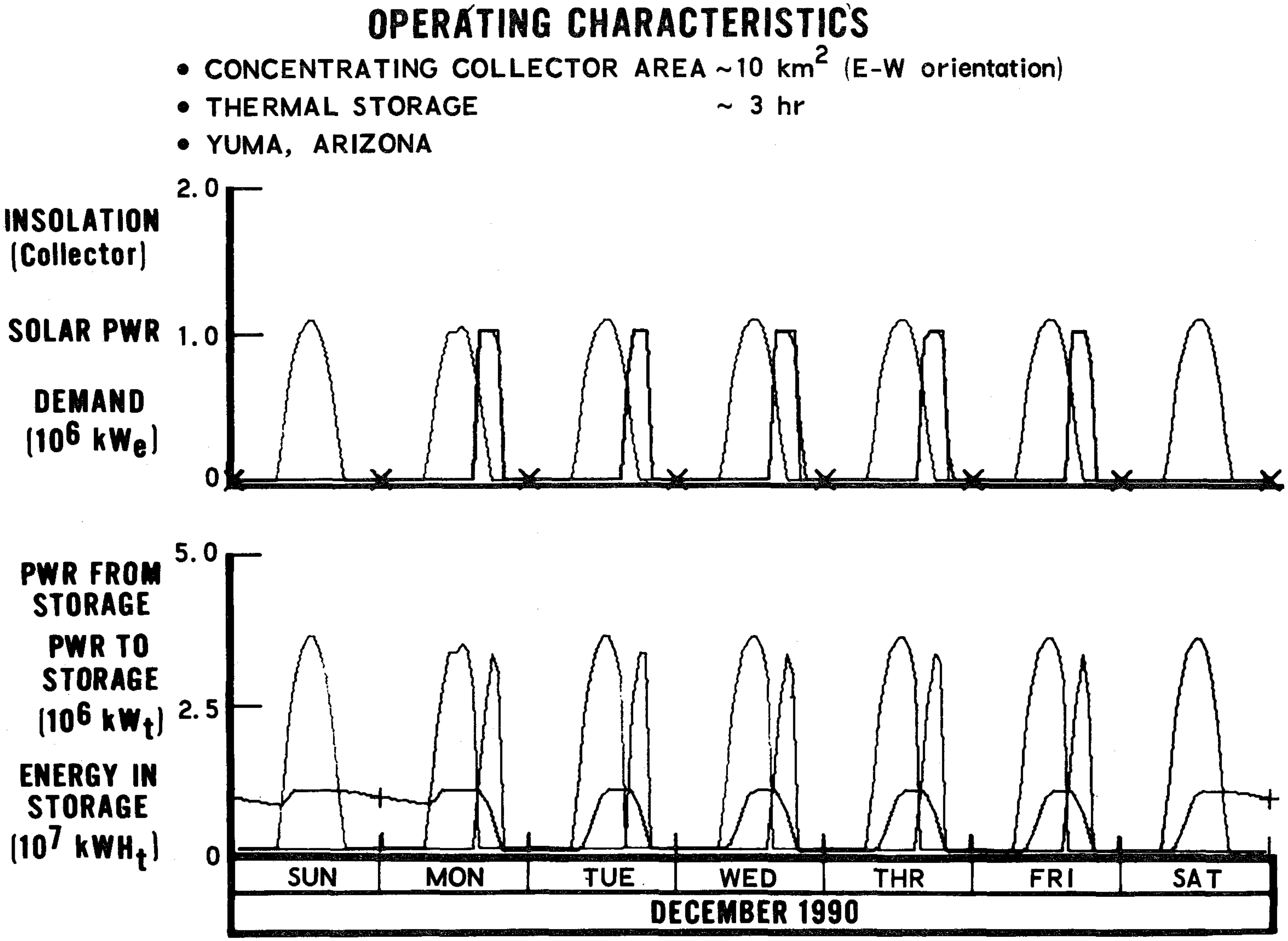


Figure 2-10. Peaking Solar Thermal Conversion Plant (1000 MWe) Operating Characteristics

2.4.10 Peaking Load Solar Power Plants - Technical Performance

The parametric technical performance characteristics for peak-load solar power plants are shown in Figure 2-11. The collector area and storage capacity were varied parametrically for the solar plant with a fixed 1000-MWe generator rating.

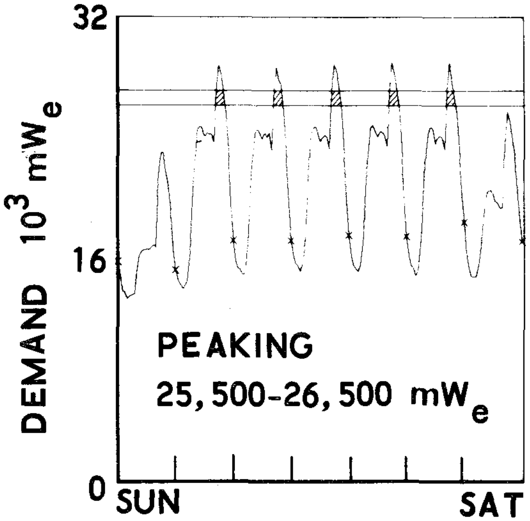
Shown in Figure 2-11 are the plant capacity factor and energy displacement for the various combinations of collector area and storage capacity when operating within 25,500 to 26,500 MWe peak-demand range. The plant capacity factor is the same as the solar capacity factor (not shown), since the maintenance period for this case can be scheduled in the beginning of the year, where no demand exists within the defined peak-demand range (see Figure 2-3).

For these peaking solar plants, solar energy may be available during periods of low or zero peak-load demand within the 25,500 to 26,500 MWe range. Because of the low marginal cost of this electrical output, the solar plant was assumed to continue operating during these periods to displace intermediate and base-load energy. No capacity displacement was assumed for this additional energy displacement.

The intermediate and base-load energy displacement and the associated incremental capacity factor are shown in Figure 2-12 for various combinations of collector area and storage capacity. The plant essentially operates in a load-following mode, with only capacity displacement assumed within the specified peak-demand range of 25,500 to 26,500 MWe.

Those collector area and storage capacity combinations above the dotted line in Figure 2-12 indicate the conditions where the solar energy available is in excess of the turbo-generator rating and storage capability. Thus, the dotted line represents the maximum intermediate and base-load energy displacement potential for these cases.

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



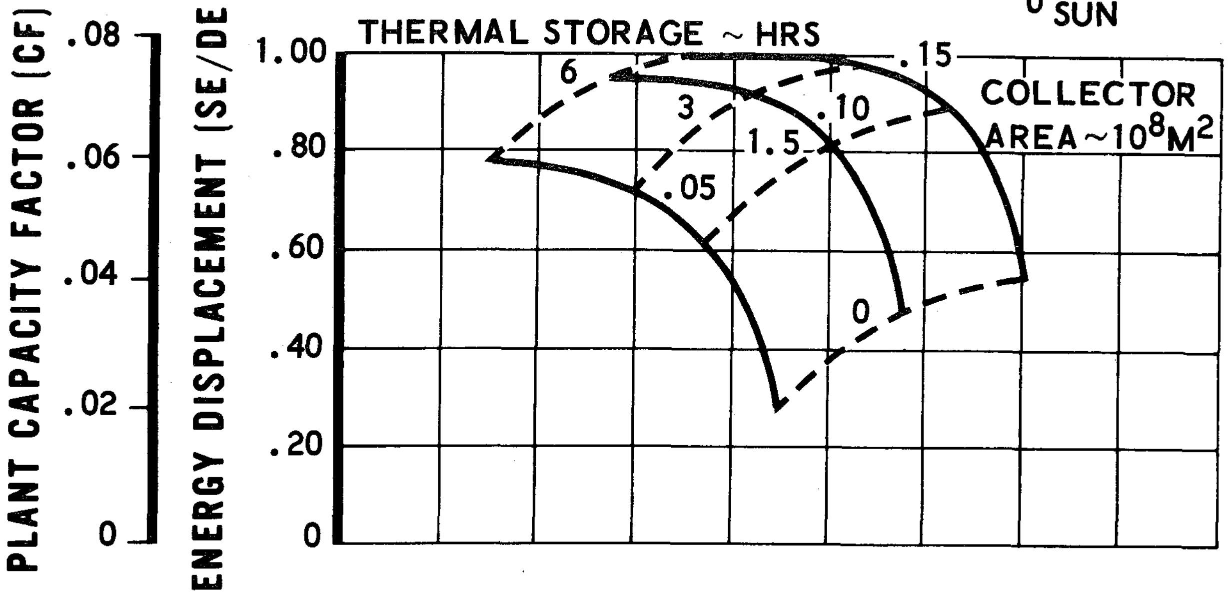


Figure 2-11. Peaking Solar Thermal Conversion Power Plant

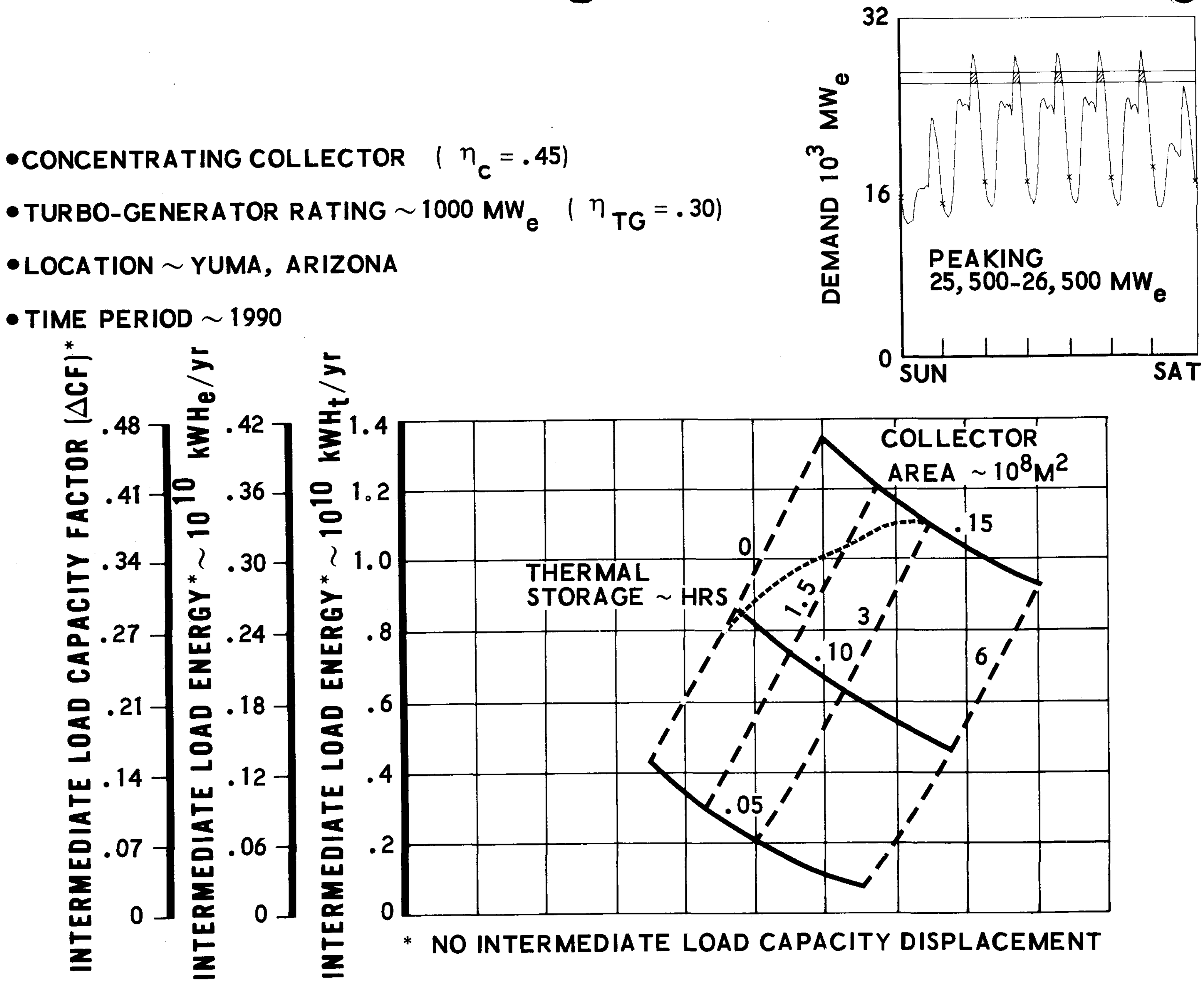


Figure 2-12. Peaking Solar Thermal Conversion Plant, Energy Displacement and Incremental Capacity

The plant capacity factor, capacity displacement, and intermediate and base-load fuel displacement are the factors required for economic evaluation of solar thermal conversion plants applied to peak-load applications.

The analyses described in this section illustrate the application of the system simulation methodology. The technical performance of a specific solar thermal conversion concept has been parametrically assessed for base, intermediate, and peaking operating modes. Additional parametric analyses can also be conducted to examine other operating ranges, increased numbers of solar plants of varying sizes, and geographically dispersed solar plants. Furthermore, when more detailed subsystem descriptions of alternate solar power plant concepts become available, the simulation can be increased in complexity to reflect major system design characteristics and to examine the effect and sensitivity of design parameters.

3. MARGIN ANALYSIS

3.1 INTRODUCTION

In order to provide reliable service to the public during times when forced outages are experienced at some generating stations, the installed generating capacity for U. S. utility companies is designed to be in excess of the anticipated peak loads. This incremental generating capacity over peak load is called the margin. The margin requirements for utility systems arise due to unscheduled outages at particular plants which, for conventional power plants, are due to component failures. These unscheduled outages are separate from outages for scheduled maintenance and seasonal deratings of power plants.

When Solar Thermal Conversion solar plants are integrated with conventional nuclear and fossil power plants in a total power grid, a margin analysis must be performed to ensure that the new system with solar plants provides equally reliable electric service. If, because of this criterion, a solar plant requires conventional backup generating capacity, this standby capacity must be taken into account when making a comparative economic evaluation. Consequently, as shown in Figure 3-1, the principal issue is to establish the potential of solar power plants to provide capacity displacement as well as energy displacement when functioning in realistic operating environments.

In addition to component outages, solar plants may also have solar insolation outages. These insolation outages occur during nonsunshine hours and periods of cloud cover. The occurrence and time durations of these outages will greatly affect the amount of energy storage required or conventional backup needs such as in a hybrid plant. Since energy storage or hybrid plants are expensive, an economic tradeoff must be made between the amount of storage and associated larger collector field, and the outage

PRINCIPAL ISSUE

- ESTABLISH THE POTENTIAL OF SOLAR POWER PLANTS, IN REALISTIC OPERATIONAL ENVIRONMENTS, TO PROVIDE CAPACITY AS WELL AS ENERGY DISPLACEMENT

SOLAR PLANT IMPLICATIONS

- SOLAR PLANT OUTAGE RATE
  - MECHANICAL & INSOLATION
  - STORAGE OR HYBRID OPERATION
- CORRELATION OF INSOLATION OUTAGE AT SEPARATE PLANTS
  - GEOGRAPHIC DISPERSION
  - PLANT SIZE
- CORRELATION OF INSOLATION AND DEMAND
  - SEASONAL & DAILY INSOLATION WITH DEMAND VARIATIONS
  - WEATHER IMPACT ON INSOLATION & DEMAND

Figure 3-1. Margin Analysis, Electrical Power Systems rate with the associated backup capacity.

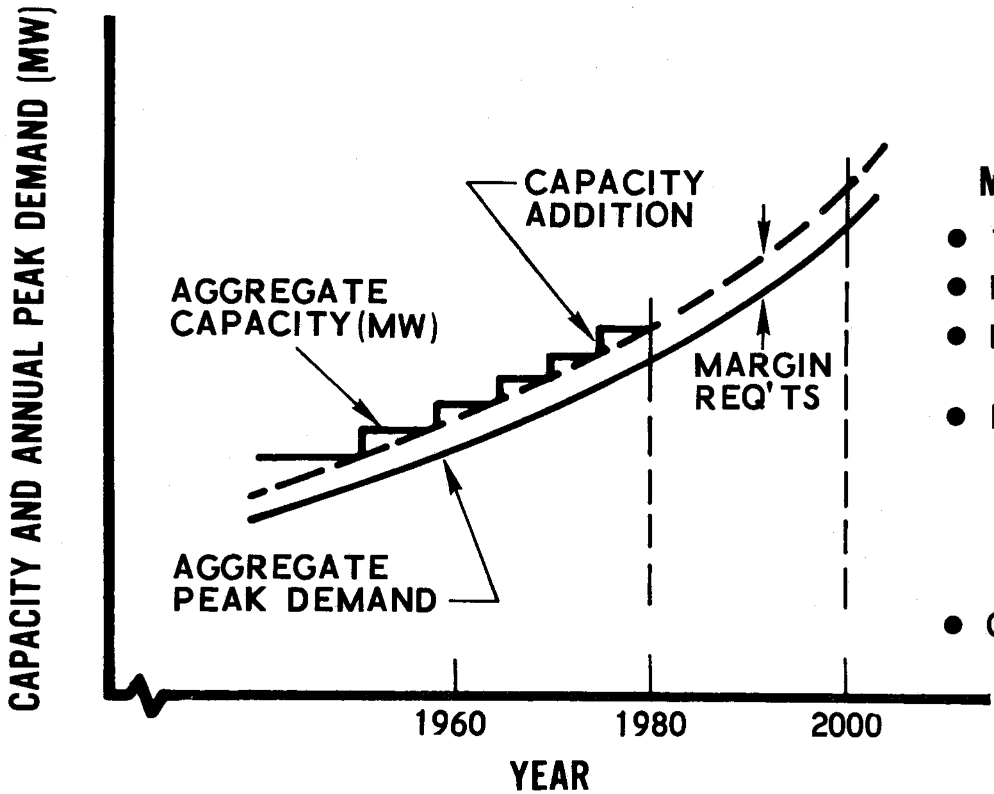
Two correlation analyses that may significantly impact the margin requirements for solar power plants have been identified. In contrast to component outages at different power plants, which are statistically independent, insolation outages are concurrent for solar plants in the same geographic region. By geographic dispersion of solar power plants, a degree of statistical independence may be introduced related to the variability of cloud cover between different locations.

In addition to the potential for statistical independence of geographically dispersed solar plants, the correlation between insolation and demand has a significant bearing on the margin requirements and, hence, the potential of capacity displacement of solar power plants. Besides the normal seasonal and daily insolation and demand variations, a statistical dependence between high insolation and peak demand would reduce the margin requirements of systems that include solar power plants.

3.2 DEFINITION AND APPROACH

Margin is a safety factor that assures that even in the event of component failures at one or more plant units, the electrical demand will not exceed the remaining generating capacity at a given time. When solar electrical generating plants are considered as part of the total system, the added possibility that the solar insolation will be lower than anticipated can also be regarded as an unscheduled outage similar to a failure of some component in the system. Therefore, solar insolation outage considerations must be taken into account in the margin analysis involving solar power plants.

The definition of margin is shown graphically in Figure 3-2. Depicted is the annual peak demand for electric power as a function of years, such as provided by the California Power Utility Commission. Since there is a



MARGIN CALCULATION APPROACH

- 15-20% OF PEAK DEMAND
- LOSS OF TWO LARGEST RISKS
- LOSS OF LARGEST RISK PLUS 7% PEAK DEMAND
- PROBABILISTIC CALCULATIONS
  - LOSS OF LOAD
  - TIME AND DURATION

RELIABILITY CRITERIA

- ONE DAY IN TEN YEARS

Figure 3-2. Margin Analysis, Definition and Approach lead time required in the installation of new generating units of several years, the required margin must be projected years in advance. This means that annual peak loads must be projected well in advance and, therefore, errors that are involved in the projection of demand must also be considered in determining the margin requirements. The generating capacity required by the utility company to supply this demand reliably is shown by the dotted line. The incremental generating capacity over peak demand for a particular year, expressed as a percent of the peak demand, is the margin. A utility company provides for the growing demand by adding discrete plants to the power grid; consequently, the actual margin varies in a discontinuous manner.

There are various approaches to calculating the margin requirements. The simplest and one of the oldest approaches is to provide a generating capacity 15 to 20 percent in excess of peak demand. With the addition of very large power plants, some utilities adopted the loss of the two largest risks or, alternatively, the loss of the largest risk plus 7 percent of peak demand. Because of the increased capital investment costs of power plants, a more precise determination of total generating requirements is desirable, which is based on probabilistic calculations, subject to a loss of load criterion. The most widely used method based on probabilistic techniques is called the "Loss of Load" method. This method measures the required reserve as a function of the probability of loss of capacity to meet demand. The term loss of load will usually be expressed in terms of days per year that some loss of load can be expected. The duration of the loss is unspecified. A common criterion for the loss-of-load reliability of a system is one day in ten years. This means that on the average, over a ten year span, an electric generating system with this reliability would have an aggregate loss of load condition of only one day. A more complex calculation in which the duration of outages is included is the "Time and Duration" method. This method requires a great deal of input data which is normally not available for many systems. For purposes of this study, the loss-of-load probabilistic approach was adopted.

3.3 INPUT REQUIREMENTS

The necessary elements required in applying the loss-of-load probability method depend on the amount and nature of the available generating capacity and the variability and magnitude of the demand or load. These elements are called the generation model and the load model. The typical input requirements to probabilistic margin analyses are shown in Figure 3-3.

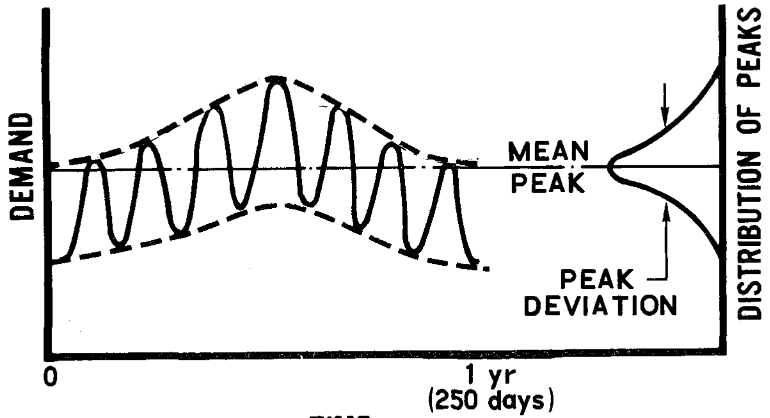
The load model is a statistical description of the electric demand for a full year, excluding weekends and holidays, since these are days with low peak demands. Consequently, the load model is based on a 250-day year and computes the statistical description of the peak demand characteristics.

The generation model incorporates the various power plant units within a power grid as a function of their individual capacities and outage rates. This permits a calculation of the probability that a given amount of generating capacity is available. This probability distribution is referred to as the capacity model.

The system loss-of-load calculations which typically use a reliability criterion of one day in ten years combine the generating capacity probability with the probability that the demand load exceeds this capacity.

The forced outage rates for conventional power plants are a function of type, size, and maturity of power plants. Some typical values are shown in Figure 3-3. The actual generation, capacity, and load models used in this study will be discussed in more detail in subsequent sections.

LOAD MODEL



FORCED OUTAGE RATES (MATURE UNITS)

NAMEPLATE RATING (mW)	RATE %
EXISTING FOSSIL	
0-100	1.5
101-300	3.9
301-500	5.5
FUTURE FOSSIL	
600	5.8-7.8
800	6.7-9.4
1000	7.4-10.7
FUTURE NUCLEAR	
600	5.1-7.2
800	5.8-8.7
1000	6.5-10.0

GENERATION MODEL

UNIT ID	CAPACITY (mW)		OUTAGE RATE		SCHEDULED MAINTENANCE
	FULL	PARTIAL	TOTAL	PARTIAL	
HYDRO No. 1	100	50	1	1	-
COAL No. 3	800	700	5	8	-
NUCLEAR No. 1	1140	900	6	12	-
GAS TURBINE No. 4	140	-	5	-	-
SOLAR No. 9	200	150	8	20	-

IMMATURE AND OLD PLANTS

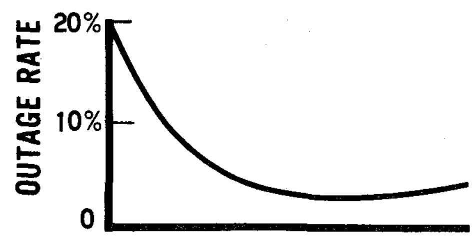


Figure 3-3. Margin Analysis, Input Requirements

3.4 METHODOLOGY COMPARISON

Computations involved in formulating capacity, load, and reliability models can be lengthy and quite complex when dealing with large electrical generating systems and require sophisticated mathematical techniques. Present day computers permit lengthy computations to be performed rapidly and accurately, but alternatives do exist in the methodology selected.

For this reason, a number of different methodologies were examined from the standpoint of assessing their relative accuracy, flexibility, and other advantages or disadvantages.

One of the most critical elements from a computational viewpoint is the determination of the capacity model. In the capacity model formulation of a large system, consideration must be made of literally billions of combinatorial possibilities of available generation capacities and their associated probabilities. Analysis of conventional and solar plant units operating at partial outage rates adds to the dimension of the problem. Consideration of correlated outages for solar plants and scheduled maintenance complicates the analysis even further.

Even if the selected methodology which takes all of these effects into account uses only a few minutes of computer time for each separate case examined, computational time differences are important. The reason is that for parametric analyses, many cases must be examined.

The various margin methodology routines presently operational are summarized in Figure 3-4. The binomial method provides an exact solution; however, this method is limited to a small number of plant units, due to computer limitations and costs. Furthermore, this method is limited in flexibility.

METHODOLOGY	ADVANTAGES	DISADVANTAGES
BINOMINAL	EXACT SOLUTION	HIGH COMPUTER COST • SMALL No. OF PLANTS LIMITED FLEXIBILITY
ALGORITHM	EXACT SOLUTION LOW COMPUTER COST	LIMITED FLEXIBILITY • PARTIAL OUTAGE • CORRELATED OUTAGES • SCHEDULED MAINT.
MONTE CARLO	REASONABLE COMPUTER COST FLEXIBLE • PARTIAL OUTAGE • CORRELATED OUTAGES • SCHEDULED MAINT.	APPROXIMATE SOLUTION NOISE

Figure 3-4. Margin Analysis, Methodology Comparison

As a consequence, two methods were adopted, an algorithm solution and a Monte Carlo routine. The first method was obtained from the Southern California Edison Company. This method solves the binomial problem by means of an algorithm, thereby providing an exact solution while significantly reducing computer costs. The disadvantage of this method is limited flexibility when trying to incorporate correlated outages for solar plants with scheduled maintenance.

These disadvantages are compensated for by the Monte Carlo method at the expense of slightly increased computer costs. A disadvantage of the Monte Carlo method is that this approach provides an approximate solution requiring a large number of trials.

3.5 METHODOLOGY COST COMPARISON

The various margin methodologies were compared on the basis of computer cost. A 10, 30, and 100-unit power plant system with each unit having a capacity of 100 MWe, and an unscheduled outage rate of 2 percent were analyzed by the algorithm and Monte Carlo methods and compared to the exact solution. Since all unit capacities and forced outages were the same, an exact solution to the capacity model could be obtained by simple binomial techniques. The probabilities of available capacity for the 100-unit system are shown in Table 3.1. As can be seen, the algorithm method is an exact solution, while the Monte Carlo method provides an approximate solution, with improved accuracy as the number of trials are increased.

Comparing the relative computer costs, the Monte Carlo approach with 10,000 trials has a slightly higher computer time than the algorithm method; however, the former method is more flexible for statistical analysis.

Table 3-1. Margin Analysis, Methodology Comparison

100 UNIT SYSTEM, 100 mW EACH, 2% OUTAGE

SYSTEM CAPACITY mW	PROBABILITY OF AVAILABLE CAPACITY			
	EXACT SOLUTION	ALGORITHM	MONTE CARLO TRIALS 1000	MONTE CARLO TRIALS 10,000
10,000	0.13262	0.13262	0.127	0.1289
9,900	0.27065	0.27065	0.269	0.2721
9,800	0.27342	0.27342	0.258	0.2756
9,700	0.18227	0.18227	0.189	0.1842
9,600	0.09021	0.09021	0.108	0.0891
9,500	0.03535	0.03535	0.035	0.0351
COMPUTER RUNNING TIME-sec	--	3.6	0.417	5.288

Both of these methods were subsequently applied to the margin calculations of a postulated power system to determine the capacity displacement potential of solar power plants when integrated into a total power grid.

3.6 SIMPLIFIED EXAMPLE

3.6.1 Simple Capacity Model

For the probability calculations of system reliability, the capacity model must consider all possible combinations of generating capacity of the various plant units comprising the total system and their associated component outage rates. In the case of solar plant units, in addition to component outage rates, the outages due to insolation must also be included.

For illustration of the development of the capacity model, a simple generation model consisting of only four conventional units with capacities of 150, 125, 100, and 75 megawatts respectively was selected. In this system, each unit is either operating (in) or not operating (out). For this illustrative example, it was assumed that each of the units has a forced component outage rate of two percent. (An unscheduled failure downtime frequency equal to two percent of the time.) This example produced the capacity model shown in Table 3.2.

The fact that each generator is either "in" or "out" results in a two-state system. In the case of this example consisting of four units operating in either of two states, there are 2^4 or 16 combinatorial variations. A two-state system comprised of 300 units would have $2^{300} \simeq$ or 2×10^{90} combinatorial variations. This number of combinations is in excess of present day computer capabilities. Consequently, the number of combinations for a realistic system requires the use of

Table 3.2 Illustrative Simple Capacity Model

Unit Capacity (MW) 150	125	100	75	Total capacity available (Mw)	Probability of occurrence		
In	In	In	In	450	......$(0.98)^4$	=	0.92236816
In	In	In	Out	375	$(0.98)^3(0.02)$	=	0.01882384
In	In	Out	In	350	$(0.98)^3(0.02)$	=	0.01882384
In	Out	In	In	325	$(0.98)^3(0.02)$	=	0.01882384
Out	In	In	In	300	$(0.98)^3(0.02)$	=	0.01882384
In	In	Out	Out	275	$(0.98)^2(0.02)^2$	=	0.00038416
In	Out	In	Out	250	$(0.98)^2(0.02)^2$	=	0.00038416
Out	In	In	Out	225	$(0.98)^2(0.02)^2$	=	0.00038416
In	Out	Out	In	225	$(0.98)^2(0.02)^2$	=	0.00038416
Out	In	Out	In	200	$(0.98)^2(0.02)^2$	=	0.00038416
Out	Out	In	In	175	$(0.98)^2(0.02)^2$	=	0.00038416
In	Out	Out	Out	150	$(0.98)\ (0.02)^3$	=	0.00000784
Out	In	Out	Out	125	$(0.98)\ (0.02)^3$	=	0.00000784
Out	Out	In	Out	100	$(0.98)\ (0.02)^3$	=	0.00000784
Out	Out	Out	In	75	$(0.98)\ (0.02)^3$	=	0.00000784
Out	Out	Out	Out	0	......$(0.02)^4$	=	0.00000016
							1.00000000

more sophisticated techniques or approximations which make the solution of the problem feasible.

Fortunately, alternative techniques exist for determining the capacity model which are easily handled by computers. These alternative techniques were discussed in the previous sections together with their relative advantages and disadvantages.

3.6.2 Simple Load Model

As mentioned previously, the load model to be used in the calculation of the overall system reliability is generated from the time history of the demand taken over the span of a year. Weekends and holidays are omitted from the data since peak demands on those days are much lower than for the five working days. This results in a sample data year consisting of 250 days, although the time span covered is 365 days.

Load models may be quite complex; however, a simple model is shown here to illustrate the basic analysis. Based on a representative time span, usually a year, the demand profile is broken down into blocks or levels. The percentage of the time that the demand falls within these levels is calculated. Shown in Table 3.3 is the load model for a typical system (this load model does not represent any system studies in this analysis and is used for illustration only). From the table it is apparent that the demand virtually never exceeds 370 MW and is always above 250 MW for this example.

3.6.3 Loss of Load Calculation

As discussed in the previous sections, the determination of generating capacity reserve or margin is necessary to provide the required degree of insurance that generating capacity will be available to meet demand

Table 3.3 Illustrative Load Model

Load Blocks (MW)	Probability of occurrence	Cumulative probability (probability load has value shown or higher)
359 - 370	0.0012	0.0012
347 - 358	0.0085	0.0097
335 - 346	0.0384	0.0481
323 - 334	0.1105	0.1586
311 - 322	0.2107	0.3693
299 - 310	0.2614	0.6307
287 - 298	0.2107	0.8414
275 - 286	0.1105	0.9519
263 - 274	0.0384	0.9903
251 - 262	0.0085	0.9988
239 - 250	0.0012	1.0000
	1.0000	

at any specified time. The determination of the margin requirements depends upon interrelating projected capacity and projected demand, and setting up a criterion of reliability that is to be satisfied.

The margin requirements are determined using the example capacity model and load model shown in Tables 3.2, and 3.3 respectively. These are combined in the manner shown in Table 3.4. For each level of generation available, the probability that the load will exceed this amount is indicated. Combining the generating capacity probability with the probability that the demand load exceeds this capacity results in the loss of load for this system.

For a given level of generation, the product of the probability of its availability and the probability that the load will exceed that level is the probability of a loss of load at this level. The total loss of load probability of the system is obtained by adding the probabilities of loss of load for all possible levels of generating capacity in the system, since all generating capacity levels are mutually exclusive. The total probability of loss of load for this example case is 0.01736 per unit of time. The example load model was based on a 250-day year. Therefore, the number of days of loss of load per year is:

$$(0.01736) \times (250) = 4.34 \text{ days/year.}$$

This example calculation results in a system reliability that is much lower than is acceptable under present day utility standards. The reliability criterion used by many utilities is an expected loss of load not to exceed one day in ten years.

10 yr = 2500 days

$\frac{1}{2500} = \frac{4}{10{,}000} = 4 \times 10^{4} = .0004$

3.7 MARGIN REQUIREMENTS

Figure 3-5 shows the relationship of the margin requirements as a function of the number of plants within a given system.

Table 3.4 Example Loss of Load Calculation

(1) Generation available (MW)	(2) Probability this generation being available	(3) Probability that loads exceed capacity	(2) x (3) Probability that load will be lost
450..........	0.92236816	0	0
375..........	0.01882384	0	0
350..........	0.01882384	0.0097	0.00018259
325..........	0.01882384	0.1586	0,00298546
300..........	0.01882384	0.6307	0.01187220
275..........	0.00038416	0.9519	0.00036568
250..........	0.00038416	0.9988	0.00038370
225..........	0.00076832	1.0	0.00076832
200..........	0.00038416	1.0	0.00038416
175..........	0.00038416	1.0	0.00038416
150..........	0.00000784	1.0	0.00000784
125..........	0.00000784	1.0	0.00000784
100..........	0.00000784	1.0	0.00000784
75...........	0.00000784	1.0	0.00000784
0............	0.00000016	1.0	0.00000016
Total Probability of Some Loss of Load.........			0.01735779

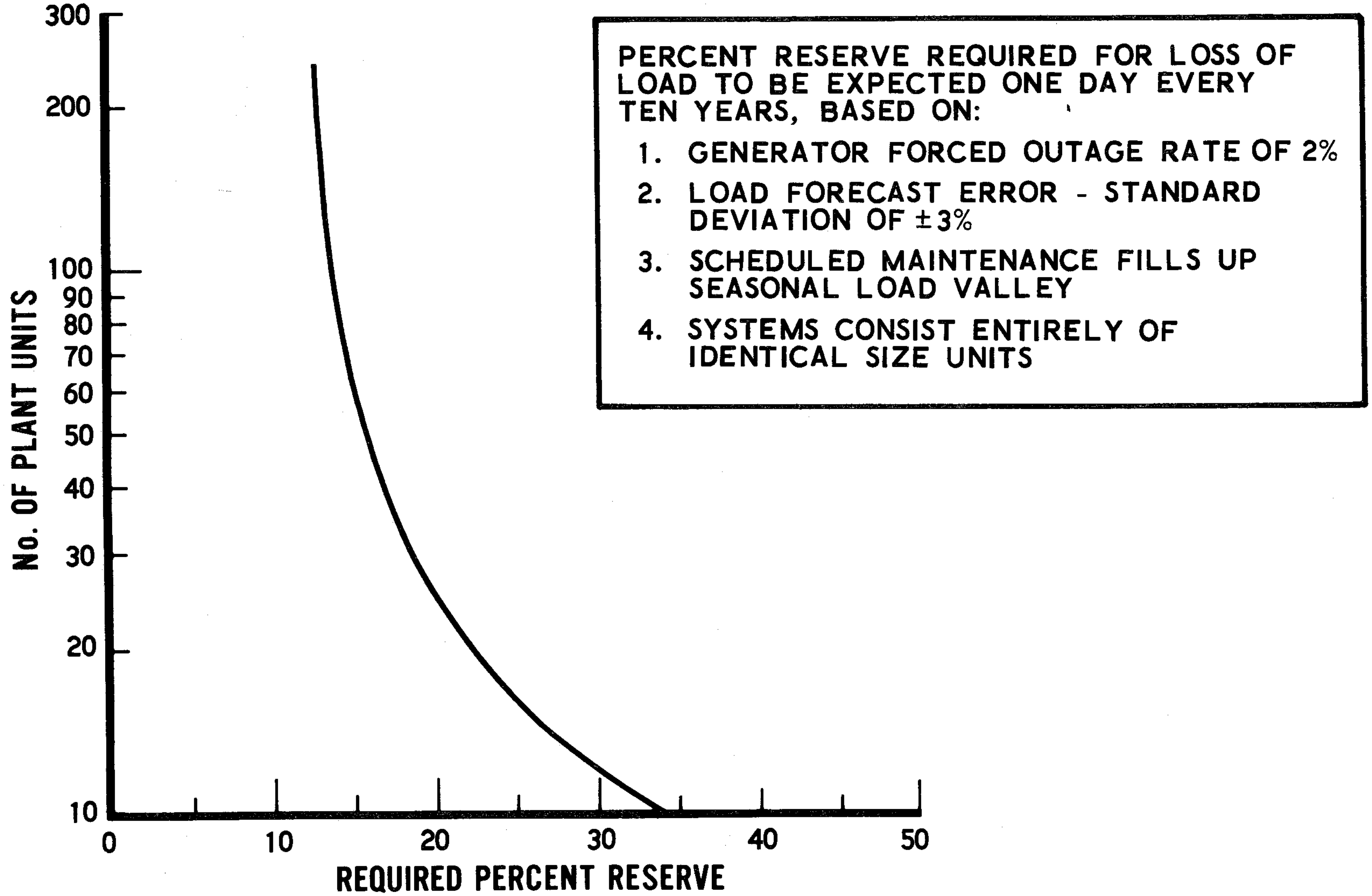


Figure 3-5. Margin Requirements

All plants were assumed to be of equal size, each with a forced outage rate of 2 percent. The load was assumed to have a normal distribution with a standard error of ±3 percent, and the loss of load was not to exceed one day in ten years. Scheduled maintenance was assumed to occur during seasonally low-demand periods. As can be seen, the margin requirements are significantly reduced as the number of plants within a system increases.

3.8 SOLAR PLANT IMPACT ON MARGIN REQUIREMENTS

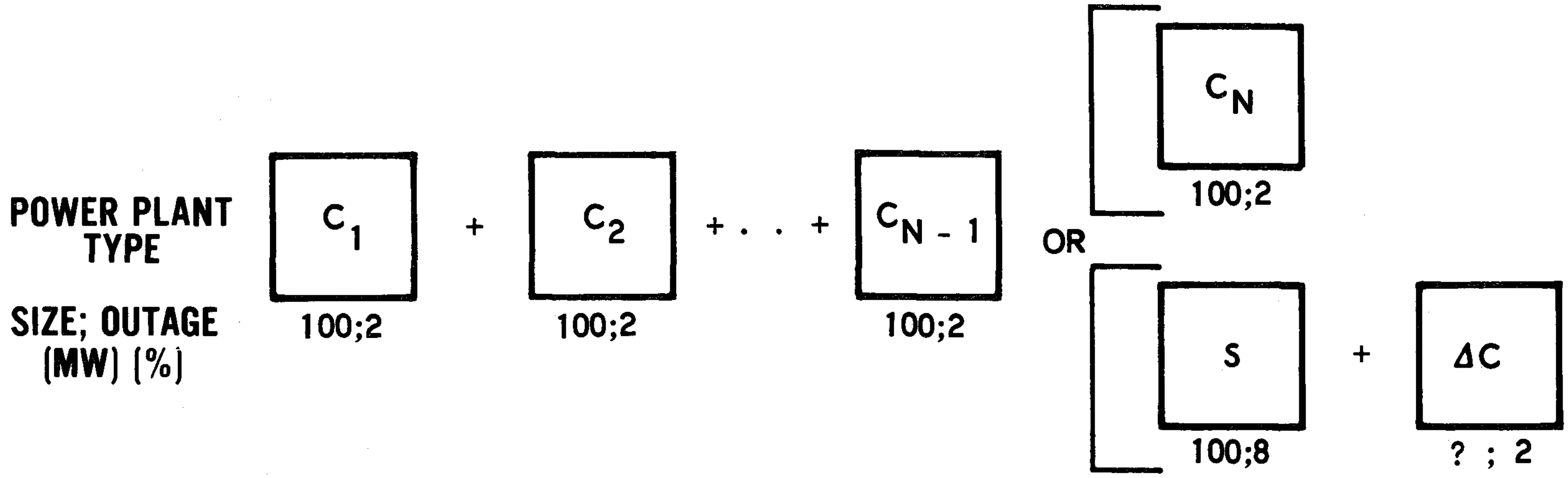
As mentioned previously, a number of margin calculational routines, based on a probabilistic approach, were developed for these analyses.

One such method, based upon binomial statistics, was used to illustrate, in Table 3.5, the impact of solar power plants on the margin requirements when operating in a power grid with conventional power plants. All calculations were performed with the reliability criterion that the loss of load equaled one day in ten years. Consequently, the total system, including the solar power plants, when introduced in the hypothetical power grid, has the same reliability of delivering electric power as when only conventional plants are utilized.

In the illustration, a conventional system comprised of N-1 units each with a capacity of 100 MWe and a forced outage rate of 2 percent is postulated. Either an additional 100 MWe conventional unit or a 100 MWe solar unit with a higher outage rate (8 percent) and an unspecified amount of conventional back up capacity is added to meet a growth in demand.

Looking at the first case (N-1 = 6 units), the conventional system requires 700 MWe generating capacity to reliably serve the 521 MWe

Table 3-5. Solar Impact on Margin Requirements



TOTAL CAPACITY (mW)		MEAN DAILY PEAK LOAD (mW)	+3 σ PEAK LOAD (mW)	MARGIN * % PEAK LOAD		CAPACITY DISPLACEMENT % OF SOLAR
C ONLY	C&S			C ONLY	C&S	
700	745	453	521	34 Δ 9	43	55
800	835	530	610	31 Δ 6	37	65
900	925	609	700	29 Δ 3	32	75

* RELIABILITY CRITERION: LOSS OF LOAD 1 DAY IN 10 YEARS

(3σ) electrical load, with a margin of 34 percent. Introducing a solar plant with an assumed outage rate of 8 percent requires a total generating capacity of 745 mWe to meet this same load with equal reliability. The margin requirements in this case are higher (43 percent), and a conventional back up capacity of 45 MWe is required. Consequently, the 100 MWe solar plant was found to have a capacity displacement of 55 mWe or 55 percent for this case.

When the size of the original system is increased (N-1 = 8), the margin requirement for the conventional system is reduced to 29 percent, which effect is consistent with the previous Figure 3-5. For the case with the addition of a solar power plant, the margin is also reduced (32 percent), albeit still higher than for the all conventional system. More important, the conventional backup capacity requirement duced to 25 MWe resulting in a much higher capacity displacement of 75 percent.

This case was selected for illustration only to show the impact of the margin requirements on the comparative evaluation of solar and conventional power plants. The outage rate to be associated with a solar plant must be deduced from a detailed simulation that considers the functional use and technical performance of the solar plant.

3.9 GENERATION MODEL

It appears reasonable to begin the discussion of the Southern California generation model by examining the various utility companies serving this region.

3.9.1 Southern California Region Generation Description

The presently existing electrical generation facilities to supply the

Southern California electric load total 20, 357 MWe in capacity. Of this total capacity, slightly more than one-half (11, 085 MWe) is located within the greater Los Angeles area roughly corresponding to the southern portion of Los Angeles County and a portion of the western part of Orange County. An additional 4, 499 MWe of generation capacity in the surrounding counties raises the Los Angeles area generation capacity to 15, 860 MWe. The next largest metropolitan area, San Diego, contains 1, 085 MWe of capacity. An additional 394 MWe outside the San Diego area raises the capacity of the San Diego region to 1, 478 MWe.

Interestingly, the ratio of steam capacity to gas turbines is almost 2 to 1 for the San Diego Gas & Electric Company system. In contrast, the ratio of steam to gas turbine generation in the Los Angeles area is almost 40 to 1.

The out-of-state contribution to the total capacity is approximately 2 percent. The total in-state hydro generation capacity of 906 MWe plus 744 MWe from the Hoover Dam is about 1 percent of the total capacity. The AC and DC interties with the Pacific Northwest are rated at approximately 3, 300 MWe. The available capacity from these two interties is subject to contract agreements with the northwest utility companies and the availability of water resources. In recent times, both factors have tended to reduce the available capacity significantly below rated capacity.

Most of the plants in the Los Angeles and San Diego areas are located along the coast to allow once through cooling and only a few are located inland. The coastal plants are typically the larger plants with the largest having a rating of 806 MWe (name plate rating of 750 MWe). All of the coastal plants have been sited along beach areas, estuaries, or within harbors where the sea terrain interface is of low relief.

Much of the remaining coast has either a steep shore line relief or is designated as state beaches. However, some beach areas are held in utility ownership.

3.9.2 Generation Capacity Expansion Plans

The preparation of generation unit forecasts for 10, 20, and 30 years into the future requires much effort, information, and time. For a period into the future of approximately 10 years, each utility will usually have a fairly detailed description of its future generation needs and how the increased demand is to be met with additional generation plants. Beyond the ten-year interval, the details of future generation plans are only very broadly defined without much attention to the details of plant size, location, and type.

In a mission analysis study of the type reported in this report, it is necessary to have reasonably complete and detailed plans of the generation expected to be installed for the 1980 to 2000 time period. Contacts and discussions with the several utilities involved (Southern California Edison Company, Los Angeles Department of Water & Power, and San Diego Gas & Electric Company) produced much helpful information, but did not completely satisfy the input requirements. Consequently, it was necessary to independently prepare the plans for future Southern California generation needs for the 1980 to 2000 time period. Although the future generation plans are postulated in considerable detail, many controversial issues are involved which are not resolved. The model presented is consistent with a large number of specific considerations which are discussed subsequently and appears to be a reasonable projection for the purpose of the mission analysis study.

The approach selected in preparing the generation unit plan was to examine each of the three major utilities individually and prepare separate plans for each. Finally, the summation of all these plans, including considerations for interaction between systems, produced a plan for the entire Southern California region.

3.9.3 Generation Model Considerations

A first step was the preparation of criteria to guide the planning efforts. The elements of the planning criteria are shown in Figure 3-6.

To assess the market capture potential of solar power plants, the present and planned generating capacity must be determined for a particular region. Utility companies forecast the generating capacity requirement for planning future power plant construction, since long approval, design, and construction lead times are experienced. Such a generation model will be based on the demand forecasts and the margin requirements for reliable power delivery. Starting with the existing plant status and retirement schedules of the various plants, total plant additions can be forecast. This generation capacity can be divided by load type (base, intermediate, and peaking) as well as by fuel type. Based upon demand and economic considerations, unit plant sizes can be determined with their associated construction lead times and siting availability. For a particular utility or service area, the generation model will determine the number, size, type, and commitment time of power plants.

For a given year of the commercial availability of solar thermal conversion plants, the maximum market capture potential can be determined by assuming that all conventional power plants not committed by this time can be replaced by solar plants.

The activities associated with the preparation of the generation description as defined by the above criteria is reviewed subsequently.

- EXISTING PLANT STATUS
- UTILITY FORECASTS FOR PLANT ADDITIONS
- GOVERNMENT AGENCY DEMAND FORECASTS
- MARGIN ANALYSIS
- RETIREMENT SCHEDULES
- LOAD SPLIT: BASE, INTERMEDIATE, PEAKING
- PROPORTIONS BY FUEL TYPE
- UNIT SIZE PROJECTION
- SITE SATURATION
- CONSTRUCTION SCHEDULES

Figure 3-6. Generation Model Considerations

3.9.3.1 Existing Plant Status, Utility Forecasts

The characteristics of existing plants were secured from each of the three utilities (Southern California Edison Company (SCE), Los Angeles Department of Water & Power (LADWP), and San Diego Gas & Electric Company (SDG&E). Additional data relative to the future generating plans were supplied by the Los Angeles Department of Water & Power (LADWP) and the Southern California Edison Company (SCE). The LADWP data included forecasts to the year 2000, while the SCE projections extended only to 1983. SDG&E had not yet responded at the time this report was written.

3.9.3.2 Government Agency Forecasts

Several reports (References 21 through 30) were reviewed to extract guidelines on the number, size, and type of future generation units. No single report was found that covered the time period under study in sufficient detail to avoid synthesizing the generation model from scratch.

3.9.3.3 Margin Estimates

The generating capacity margin requirements as projected in one scenario by the SCE are shown in Table 3.6. The ten-year average based on peak demand is 20.4 percent. Based on these data and common practice in the past, it was decided to assume a 20-percent margin over peak demand for generation planning purposes.

3.9.3.4 Retirement Schedules

An analysis of the SCE planned installed generation for the year 1980 shows the average age to be 25 years. For planning purposes, SCE assumes a useful operating life of 35 years for nuclear plants, 40 years

Table 3.6 Southern California Edison Company
Capacity Margin Forecast
(Percent)

Year	Margin based on peak demand
1973	28.4
1974	21.3
1975	21.7
1976	22.3
1977	22.3
1978	19.9
1979	15.7
1980	14.6
1981	16.7
1982	20.8

for oil, gas and coal plants, and 25 to 35 years for combined cycle plants. Electric utilities have historically operated the more efficient and reliable plants to furnish the baseload demand and used the remaining plants to supply intermittent and peak load demands. Experience has shown the newer plants to be more efficient and have a lower marginal cost. For this analysis, it was assumed that a typical baseload fossil plant would have base, intermediate, and peaking operation in three equal time periods; i.e., a plant with an expected operating life of 30 years would operate as a baseload plant for 14 years, for 13 years as a intermittent plant, and the remaining period as a peaking plant. At the end of expected lifetime of the plant, the unit is assumed to be placed on cold standby. This assumption approximates past practice. However, specific information was lacking to specify the division into base, intermediate, and peaking operation.

3.9.3.5 Load Split: Base, Intermediate, Peaking

In order to determine the load split, the load duration curve for SCE during the year 1972 was analyzed. This load duration curve and an idealized curve are shown in Figure 3-7 (a). The ordinate of the load duration curve is electric power demand in percent of the peak demand, and the abscissa is percent of total hours. The area under the curve represents the electric energy production (Kwh). The integral of the load duration curve is shown in Figure 3-7 (b) which is useful in determining the load split of electric power systems.

For the SCE system, the baseload portion of the curve accounts for 66.3 percent of the electrical energy produced, while the intermediate load accounts for 33.2 percent. The total system capacity factor for the 1972 SCE load duration curve was 60.3 percent. Consequently, the total electric energy demand is:

Total Energy Demand (Kwh) = .603 x Peak Power Demand (KW) x 8760 (Hours).

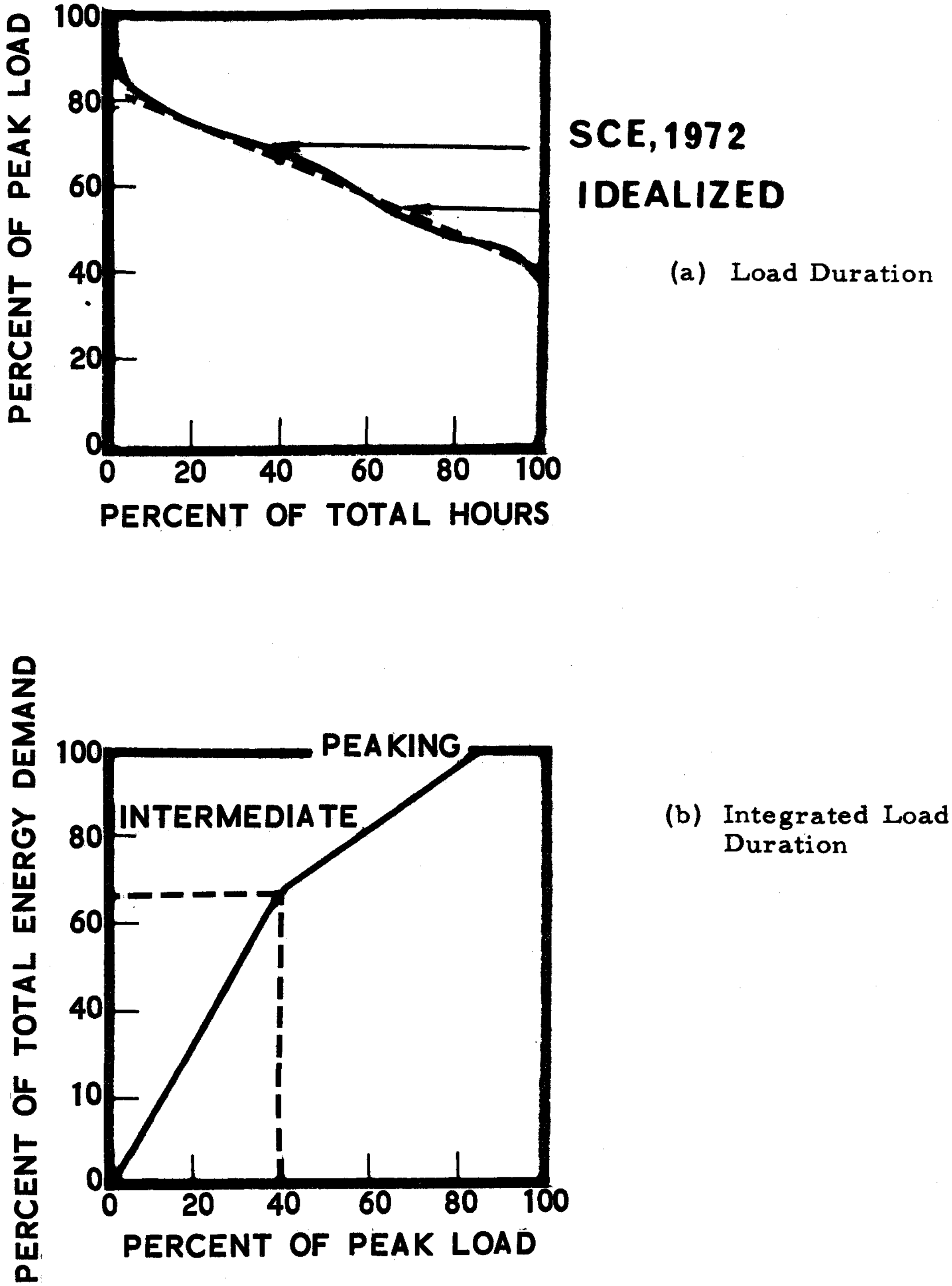


Figure 3-7. Load Duration Curves

With a margin of generating capacity over peak-power demand of 20 percent, the total energy demand in terms of total generating capacity is:

$$\text{Total Energy Demand (Kwh)} = .603 \times \left[\text{Total Capacity (KW)}/1.20\right] \times 8760 \text{ (Hours)}$$

The amount of base load and intermediate-load generation capacity was computed using the following formulation:

$$\text{Capacity (KW)} = \frac{\text{Energy Demand (Kwh)}}{\text{Capacity Factor x 8760 Hours}}$$

The peak-load generation capacity is the remainder of the total generation capacity required to meet the peak demand.

Since base-load plants account for 66.3 percent of the total energy demand, and assuming a plant capacity factor of 80 percent, the base-load capacity is 41.7 percent of the total generating capacity, or 50.0 percent of the peak power demand. The intermediate load with 33.2 percent of the total energy demand, and a plant capacity factor of 42 percent results in an intermediate-load capacity of 39.7 percent of the total generating capacity, or 47.6 percent of the peak-power demand. The peaking-load generation required is the 18.6 percent remainder of the total generating capacity, or 22.4 percent of the peak-power demand.

These proportions were used to determine the load split into base, intermediate, and peaking. For example, in the year 1990, the SCE peak demand forecast is 32,000 MWe. With a 20 percent margin, the total generating capacity required to meet this demand is 38,400 MWe. Using the above load split, the base, intermediate, and peaking generation capacities are 16,000, 16,250, and 7,150 MWe respectively.

3.9.3.6 Proportions by Fuel Type

The Atomic Energy Commission (AEC) and other agencies have made forecasts by type of generation. Table 3.7 compares the forecasts of the California Resources Agency (CRA) and the Stanford Research Institute (SRI).

These forecasts share the common characteristic of the increasing dependence upon nuclear plants for electric generation. Also the use of coal as a fuel is explicitly projected in the CRA forecast. The coal plants are expected to be located in New Mexico, Arizona, and Nevada. A total of 23,500 MW of coal plant capacity is projected by the year 2000 for Southern California.

3.9.3.7 Unit Size Projection

The maximum unit sizes assumed for various time periods are presented in Table 3.8.

3.9.3.8 Site Saturation

For the early time period (1980), the selection of sites for future power plants is fairly well established though construction of these plants is not assured. Beyond 1980 to the year 2000 such siting plans are almost nonexistent.

3.9.3.9 Construction Schedule

Sufficient lead time must be allowed for the plant construction and equipment testing followed by a period of several years for the plant to reach maturity. A construction period of five years for fossil and 7 1/2 years for nuclear power plants was assumed. Following plant start-up, two to four additional years are typically required to reach maturity. Both factors are reflected in the planning schedule.

Table 3.7 Comparison of Generation Mix Forecasts
(Percent)

Type	CRA (1991)	SRI (2000)
Nuclear	56	52
Gas & Oil	15	32*
Hydro	11	16
Geothermal	9	0
Coal	9	--
Total:	100	100

*Includes coal

Table 3. 8 Unit Size Projection

Type	Size	Time Period
Nuclear	1500 MW	to 1989
	2000 MW	1990 - 2000
Coal	1200 MW	to 1992
	2000 MW	1992 - 2000

3.10 SOUTHERN CALIFORNIA EDISON COMPANY GENERATION

Electric power generation requirements for the 1980 to 2000 time period were postulated for the Southern California Edison Company service territory as shown in Figure 3-8.

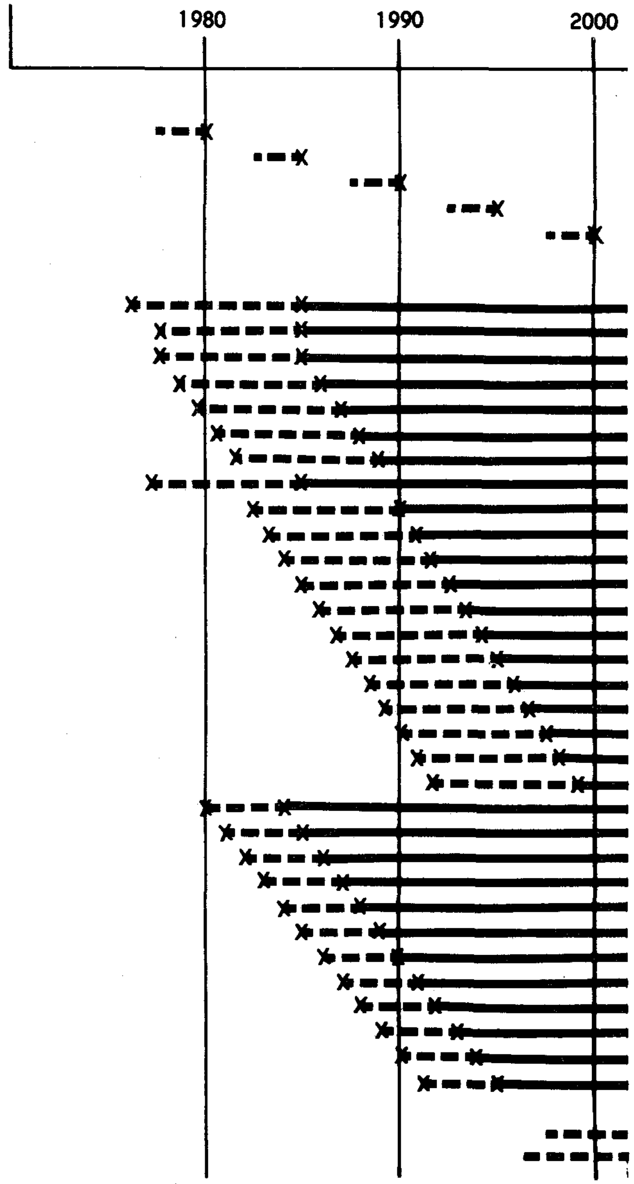
By combining the demand projections and margin requirements projected for this area (shown at the bottom of Figure 3-8) with the existing and definitely planned (through 1982) generation in the system (as shown at the top of Figure 3-8), the required generation additions by plant type and size were postulated. The assumed design and construction commitment lead times, as shown by dotted lines, are 7.5 years for nuclear and 5.0 years for fossil power plants respectively.

Assuming that solar thermal conversion plants are commercially available by 1990, solar power plants can potentially replace the addition of 10,000 MWe of nuclear and 6,000 MWe of fossil type power plants that might otherwise be committed between 1990 and 2000. Additionally, as much as 6,000 MWe generating capacity may be retired in this time period which represents an additional market potential for solar plants. Consequently, for the SCE service territory, a market capture potential based solely on schedule commitments of approximately 16,000 to 22,000 MWe is indicated for solar thermal conversion systems.

3.11 GENERATION MODEL

To determine the margin requirements and capacity displacement of solar power plants in a realistic operating environment, a conventional generation model was projected for the 1990 time period. This generation model (slightly different from that shown in Figure 3-8) consists of 89 units. Table 3.9 shows a summary of this generation

EXISTING GENERATION IN SYSTEM:	CAPACITY-mW
1980	19,200
1985	23,000
1990	22,500
1995	21,900
2000	20,200
2010	9,300
GENERATION ADDITIONS TO SYSTEM:	
NUCLEAR PLANTS	770
	1140
	1140
	1240
	1240
	1240
	1500
	1160
	2000
	2000
	2000
	2000
	2000
	2000
	2000
	2000
	2000
	2000
	2000
	2000
COAL PLANTS	1200
	1200
	1200
	1200
	1200
	1200
	2000
	2000
	2000
	2000
	2000
	2000
GENERATION COMMITTED PRIOR TO 2000	
NUCLEAR	4000
COAL	2000



	1980	1990	2000
TOTAL CAPACITY, mW	19,200	39,100	72,800
% MARGIN @ PEAK	15%	22%	21%

Figure 3-8. Postulated SCE Generation in 1980 to 2000

Table 3-9. Margin Analysis, Generation Model

UNIT	mW	OUTAGE
1	70	1.4%
2		
3		
4		
5		4.5%
6		5.0%
7		
8		
9		
10		
11		
12		
13		
14	150	1.4%
15		
16		2.2%
17		
18		
19		
20		
21		
22		4.5%
23		
24		
25		
26	235	0.4%
27		
28		
29		
30		
31	235	0.4%
32		
33		
34		
35		
36		
37		
38		
39		
40		1.4%
41		2.2%
42		
43		
44		
45		
46		
47		4.5%
48		
49		
50		
51		
52	330	2.8%
53		
54		
55		
56		
57		
58		3.2%
59		4.5%
60		
61	440	0.4%
62		
63		
64		
65		3.2%
66		
67		
68		
69		4.5%
70		
71	760	3.7%
72		
73		5.7%
74		
75	910	3.7%
76		
77	1000	
78	1140	5.7%
79		
80		
81		
82	1210	3.7%
83		
84		
85		4.5%
86		
87		
88		
89		

TOTAL 36290 MW

model in terms of the various power plant capacities and outage rates. The total generating capacity of the 89 units of 36,290 MWe was configured to meet the 1990 projected peak demand of 32,000 MWe for the Southern California Edison Company service territory with an outage rate of less than one day in ten years. The associated margin, excluding any provision for scheduled maintenance, is approximately 14 percent.

3.12 OUTAGE RATES

The problem of the computation of a capacity model for a large system is further complicated by the fact that the individual generating units are not necessarily operating in an "in" or "out" mode, but can be operating at partial capacity. Depending upon the number of partial states of operation, the model becomes a three-state (or larger) system.

States in which only a part of the maximum capacity is available is particularly characteristic of solar electric generating units because of the variation in the level of solar insolation caused by the position of the sun and by cloud cover. A solar electric generating plant may in general operate at many different levels ranging from the minimum operating level to the maximum rated output of the generator. The solar unit then becomes a many-state device, which should be taken into account in the development of the capacity model.

From the systems simulation model discussed in an earlier section, solar outage distributions for many states have been obtained using insolation data for Yuma, Arizona, (see Volume III) and demand for the SCE territory projected for the year 1990. The resulting solar outage distributions indicated that the assumed solar power system, with moderate energy storage, can be reasonably approximated as a two-state system rather than the multi-state system as had been presupposed. The major cause of this result is due to the energy storage component in the system which tends to smooth out the effects of cloud cover and darkness.

Typical solar outage distributions corresponding to baseload, intermediate, and peaking load applications are shown in Table 3.10. Realistic solar outage distributions such as these have been used in the computation of the capacity models. Use of solar outage distributions as illustrated in Table 3.10 result in capacity models different from one another depending upon the number of solar units in the generation model and the mode of application. The appropriate capacity model was used for each case simulated in the study.

3.13 DEMAND MODEL

The demand model profile for the 1990 time period shown in Figure 3-9 was developed using the demand decomposition/recomposition model discussed in Volume II. This load profile is based upon the 32,000 MWe (3 σ) peak demand forecast, combined with the seasonal and hourly indices determined from historic load data from the Southern California Edison Company.

This demand model, in conjunction with the generation model, allows determination of the margin requirements required to meet the reliability criterion of the loss of load not to exceed one day in ten years. By substituting one or more solar plants with associated outages within this system, and requiring the same reliability of service, the capacity displacement potential of the solar plants can be determined.

The larger the capacity displacement, the smaller the conventional

Table 3.10 Typical Solar Outage Rates
(Percent of Time)

Solar Power/ Demand (percent)	0	5	10	15	20	25	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
Baseload (30/12)*	9	0	0	1	0	0	0	1	0	0	1	0	0	1	0	0	1	0	1	1	84
Intermediate (20/6)*	2	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	96
Peaking (15/3)*	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	99

*Collector Area (km^2)/Energy Storage (hrs.)

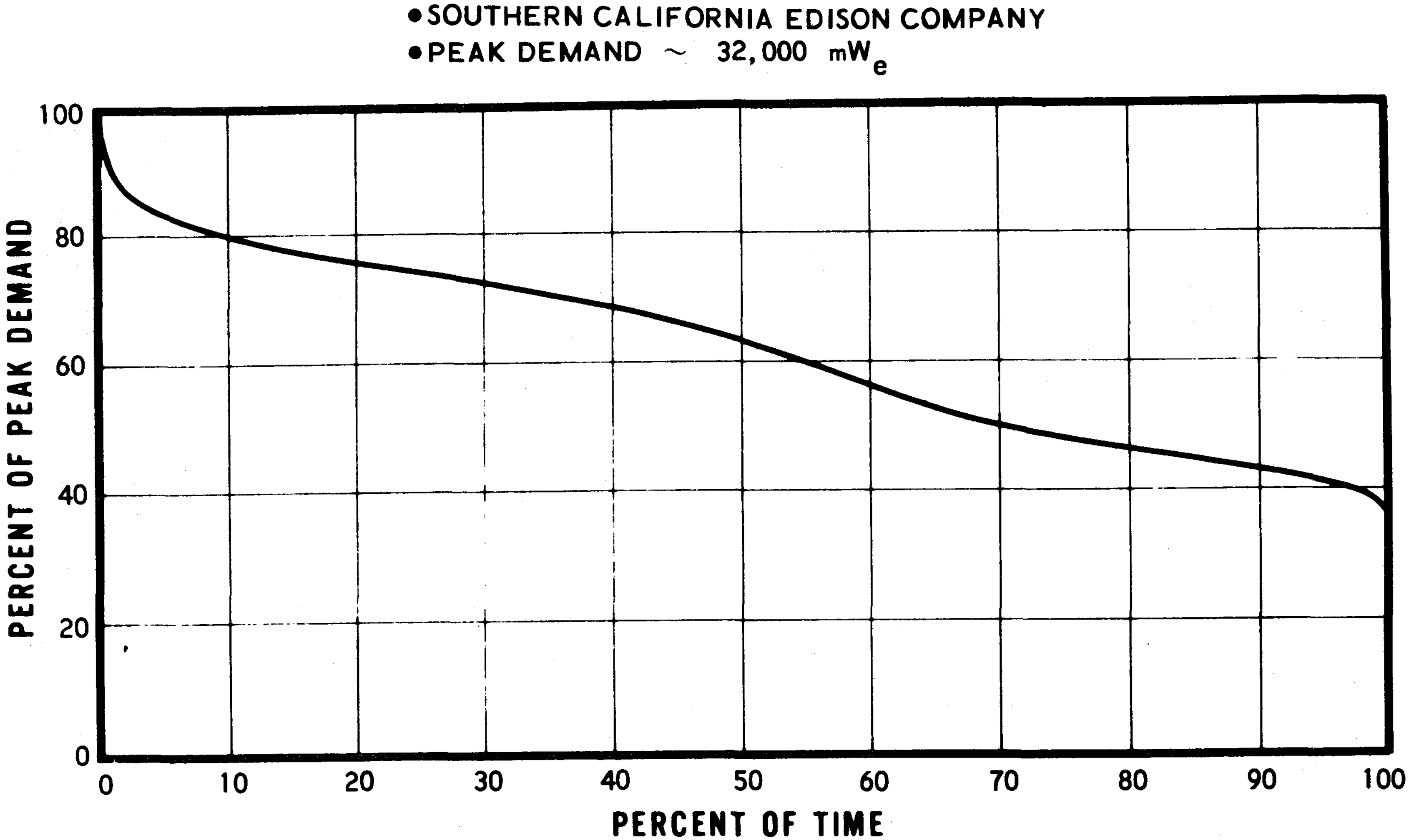


Figure 3-9. Demand Load Model ~1990

backup capacity required to meet the reliability criterion. Consequently, this has important economic implications which will be dealt with in the subsequent comparative economic evaluation of solar and conventional power plants.

3.14 CAPACITY DISPLACEMENT

Starting with the 1990 Southern California Edison generation model, consisting of 89 units with a total generating capacity of 36,290 MWe, one and two 1,000 MWe solar power plants with parametrically varying outage rates were substituted for conventional units with an outage rate of 3.7 percent.

With the requirement of servicing the 32,000 MWe peak demand with equal reliability (ensuring that the loss of load would not exceed one day in ten years), the capacity displacement of the solar plants were determined.

The resulting capacity displacement of these solar plants is shown in Figure 3-10. The specific solar plant outages must be determined from parametric system simulations of a full year's operation of these plants.

In the economic evaluation, the capacity not displaced by the solar plants was accounted for by requiring a backup capacity to be provided by additional conventional power plants.

CONVENTIONAL SYSTEM CAPACITY ~ 36,290 mWe (89 units)

LOSS OF LOAD CRITERION ~ 1 day/10 yr

PEAK LOAD (3σ) ~ 32,000 mWe

SOLAR PLANT SIZE ~ 1000 mWe

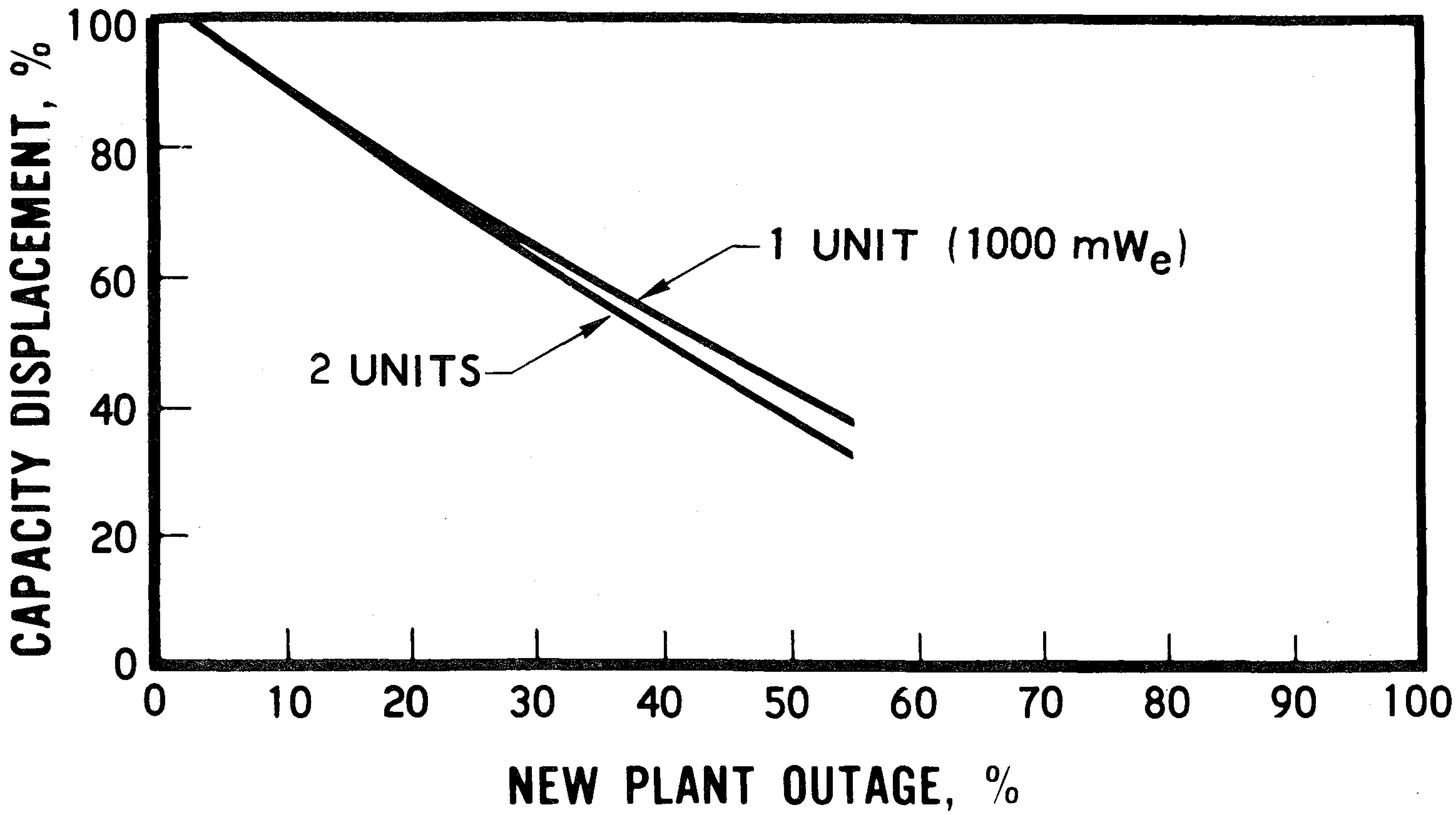


Figure 3-10. Margin Analysis, Capacity Displacement

4. ECONOMIC ANALYSIS

Having parametrically determined the technical performance of the solar power plants for different modes of operation, a comparative economic evaluation of these alternative power plants with conventional power plants was made and is discussed in this section.

4.1 SCOPE

The scope of the economic analysis effort included the development of recommended data standards which might be used by other NSF contractors to facilitate consistent economic comparisons.

The principal effort was to develop a methodology for comparative economic analyses of solar thermal power plants and conventional power plants. The methodology developed was also to be tested by an illustrative application to the extent possible. The illustrative application discussed subsequently depends heavily on the results of the Mission/Systems and Margin Analyses, which are described in preceding sections. A partially complete cost sensitivity analysis was also performed for those items which have either a large impact on the total cost or have a substantial amount of uncertainty associated with their estimates.

4.2 DATA STANDARDS

The initial effort was to recommend data standards suitable for use in other solar energy studies. The year 1972 was selected as the base year for economic data, since this is the most recent complete calendar year for which published capital and operating cost data are available. The rate of inflation, as measured by the gross national product implicit price deflator, was assumed to average three percent per year from 1972 into the future, even though fluctuatuions in this rate will occur for certain time periods. While this rate is less than the 1972-73 level, it is consistent with the long term (1958 to 1972) annual rate of 2.9 percent (Ref. 1,2). It is recognized that this three-percent rate may be too low for an analysis with 1980 as the year of commercial operation.

This rate of inflation is the basis for the projected escalation rates of six price indices. These indices and their projected escalation rates are shown in Table 4.1.

In addition, escalation rates for fifteen different capital-investment-cost categories were developed. These are essentially the Federal Power Commission two-digit accounts, such as facilities and structures, to which were added special accounts for solar collectors and thermal storage subsystems (those subsystems not found in conventional-type power plants). Each of these accounts has a composite escalation rate, and these rates are based on the proportions of construction materials, construction labor, and factory equipment. Table 4.2 shows the account numbers, title, basis, and composite escalation rates. Escalation rates for the two other direct cost investment accounts; contingency and spare parts, are determined by the composite escalation rates of the direct cost accounts in Table 4.2. The projected rate of inflation is used as the basis for these escalation values, so that a higher rate of inflation implies higher escalation rates.

Escalation rates for operating costs are shown in Table 4.3. The reason for the 0% escalation rate for insurance and property tax during the plant lifetime is that the depreciating plant value was assumed to compensate for increased insurance and property tax rates. The projected escalation rates for fuels and the effect of resource depletion on future nuclear fuel cycle costs were investigated. These escalation rates and estimates of fuel prices are discussed in Section 4.5.

Table 4.1

Price Indices Inflation Rates

Price Index	Projected Annual Escalation Rate
1. Industrial and Commercial Construction Labor and Materials (Boeckh Index of Construction Costs) (Ref. 1,2)	4.7%
2. Electrical Machinery and Equipment (Wholesale Price Index) (Ref. 1,2)	1.0%
3. All Machinery and Equipment (Wholesale Price Index) (Ref. 1,2)	1.8%
4. Iron and Steel Products (Wholesale Price Index) (Ref. 1,2)	3.6%
5. Rural Land (Department of Argiculture Index) (Ref. 3)	6.1%
6. GNP Implicit Price Deflator (Ref. 1,2)	3.0%
7. Materials*	

*Varies with Materials

Table 4.2

Capital Investment Accounts Escalation Rates

Account Number & Title		Escalation Rate Per Year	Basis*
A12	Boiler Plant Equipment	.033	3 (50%) and 1 (50%)
A20	Land	.061	5
A21	Structures	.047	1
A22	Reactor Plant Equipment	.042	1 (50%) and 4 (50%)
A23	Turbine Plant Equipment	.024	1 (24%), 2 (61%), 4 (15%)
A24	Accessory Electrical Plant Equipment	0.35	1 (69%) and 2 (31%)
A25	Miscellaneous Plant Equipment (Environmental Sys.)	.039	4 (70%) and 1 (30%)
A26	Special Materials - Nuclear	.036	4
A27	Solar Equipment	.028r	1 (25%r), 4 (10%r), 3 (55%r)**, 6 (10%r)
A28	Solar Heat Materials	Varies	7
A29	Special Construction	.047	1
A30	Miscellaneous	.03	6
A90	Indirect Construction Costs	.047	1

* Numbers reflect the price indices shown in Table 4.1 (r = revised)

** Assumes factory production of all solar collectors.

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Table 4.3

Operating Cost Escalation Rates

Category	Escalation Rate per Year
Operation & Maintenance	4%
Insurance & Property Tax	Composite of capital investment accounts to year of commercial operation. Thereafter, 0%.
Fuel	Varies with fuel type (see Section 4.5 for fuel costs and escalation).

The cost-of-capital (after taxes) is also related to the assumed rate of inflation. It is based upon historical data for the time period 1956 to 1972, assuming equal debt and equity ratios of 50 percent and a combined state and federal income tax rate of 40 percent (Ref. 4, 5). This historical time period was selected as an appropriate one to use as a basis for the future debt and equity costs, since interest rates are positively correlated with inflation. Therefore it was desireable to select a time period when the rate of inflation was about the same as previously assumed for the study time period (3 percent per year). The rate of inflation for the 1956 to 1972 time period was 2.9 percent per year. The capital structure, tax rate, and cost-of-capital used reflects values representative of the electric utility industry. The costs of debt and equity are shown in Table 4.4. Details concerning the cost of capital are discussed Section 4.3, Economic Analysis Methodology.

4.3 METHODOLOGY

The economics of solar systems is an important criterion for determining the market capture potential. By comparing the capital investment requirements and operating costs of the alternative solar missions and systems, preferred concepts can be identified. The economic feasibility of these preferred mission and systems can be determined by comparative economic evaluation of these and conventional nuclear and fossil-power plants for identical periods of commercial operation. The economic analysis methodology developed for conducting these assessments on a consistent basis is shown in Figure 4-1. The capital investment costs for each subsystem account can be estimated for a given size power plant in terms of base-year (1972) dollars. To determine the relative economics of different size power plants, an economics of scale subroutine has been included, consisting of cost scaling relationships.

Table 4.4

Historical Utility Industry Debt and Equity Costs

Year	Debt*	Equity	Net Cost of Capital**
1956	4.18	11.1	6.80
1961	4.57	11.2	6.93
1966	5.36	12.8	8.01
1972	7.50	11.6	8.05

* Before Taxes

** After taxes assuming a tax rate of 40%, and 50% debt/50% equity structure.

Source: References 3, 4.

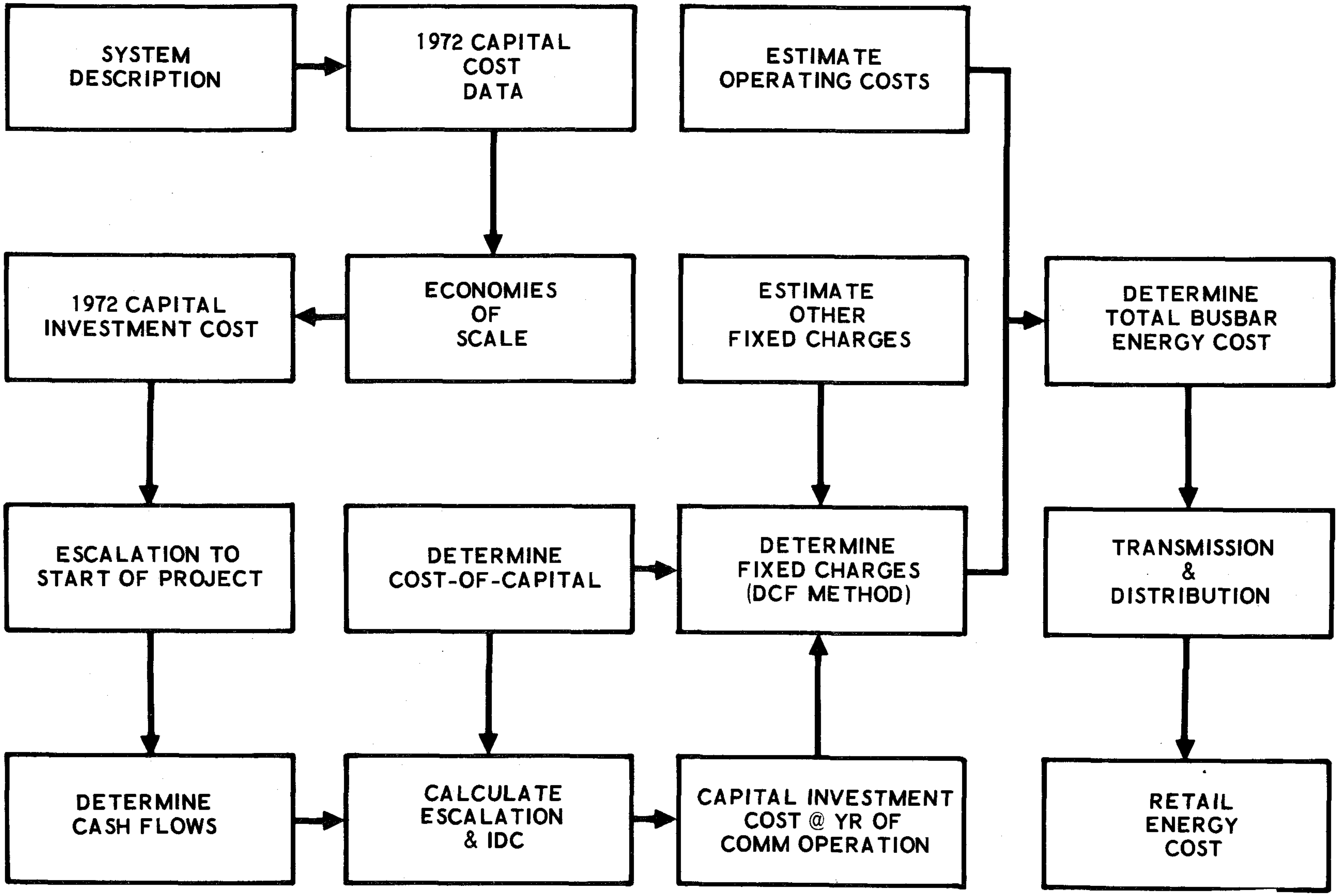

Figure 4-1. Economic Analysis Methodology

A significant contribution to power plant cost is due to escalation, which is included in the model by an escalation subroutine. This subroutine determines the escalation in costs until the start of construction. During construction, cash flows are expended which incur interest-during-construction (IDC) expenses in addition to the continued escalation of costs during the construction time period.

The base-year (1972) capital investment costs combined with the escalation and IDC determine the total capital investment cost at the year of commercial operation. Using the discounted cash flow method, the capital investment cost at the year of commercial operation together with other fixed charges such as insurance and property taxes determine the fixed charges. The cash flows are determined from pro-forma income statements, and the rate-of-discount is the cost-of-capital typical of the utility industry, which is the weighted average cost of common and preferred equity and long-term debt.

The discount rate calculates the present value of the future income cash flows during the operating life of the plant. The estimated operating costs are combined with the fixed charges to determine the total busbar energy cost using the discounted cash flow analysis method.

Transmission and distribution costs can be added to determine the retail energy costs for comparative evaluation of plants with different locations and distances from the load center.

4.3.1 Economics of Scale Model

For each two-digit investment account (Table 4.2) scaling relations were developed. These relations were normalized for a 1000-MW plant. For each direct cost investment account, these equations have the form:

$$\text{cost ratio} = a + b\,(\text{MW})^{c}$$

Two ORNL publications on capital cost estimating, are the basic source for data used to obtain these scaling equations. (Ref. 6, 7)

Thus base year costs by account may be input for a single plant size and costs for different plant sizes can be determined using these scaling relations. The resulting values for each account are summed and the base year total direct investment cost can be calculated. Accounts A40 (contingency), A41 (spare parts), and A90 (indirect costs) are derived as functions of either total direct investment or components of direct investment. Scaling equations exist for account A90 (indirect costs), but the estimates of accounts A40 (contingency) and A41 (spare parts) are derived without scaling equations.

4.3.2 Cost-of-Capital Model

The cost-of-capital is the return-on-investment required by investors as determined in the market place. This required return-on-investment relates the net cash inflows (revenues less cash expenses) over the operational lifetime of the plant with the net discounted value of the total initial investment at the year of commercial operation. This is accomplished by discounting these net cash inflows at the cost-of-capital. Interest during construction (IDC) also is computed using the cost-of-capital model.

The cost-of-capital model determines the weighted average cost of common equity, preferred stock, and long term debt, calculated after taxes. The weighting is in accordance with the proportion of each method of financing as a percent of the total market value of a typical electric utility company representative of the total electric utility industry. The rationale for selecting present market values in determining the cost-of-capital is that these values represent the investment required to replace the assets of a going concern utility company today.

Thus, the cost-of-capital can be computed from the following relationship:

$$k = (E/V)\, k_e + (P/V)\, k_p + (L/V)\, k_\ell \qquad (4\text{-}1)$$

where: (E/V), (P/V), and (L/V) are the proportions of common equity, preferred stock, and long-term debt to total market value, respectively, and k_e, k_p, and k_e are the cost of common equity, preferred stock equity, and long-term debt, respectively.

k_e is the return-on-common equity demanded by investors for this particular risk-class. Return-on-equity (k_e) can be determined from the equity valuation model for steady growth and constant dividend payout ratio. If the growth rate of earnings (E) is g and the dividends (D) are a constant percentage (1-b) of these earnings, (b = retention rate of earnings), then:

$$D = (1\text{-}b)\, E \qquad (4\text{-}2)$$

and since $E = E_o \exp(ft)$ for compound growth:

$$D = D_o \exp(gt) = (1\text{-}b)\, E_o \exp(gt) \qquad (4\text{-}3)$$

The price of common stock is determined by discounting the dividened stream at the required rate-of-return for the given risk class as determined by the investors:

$$P_o = \int_0^\infty D_o \exp(gt) \exp(-k_e t)\,dt = D_o/(k_e - g) \qquad (4\text{-}4)$$

or

$$k_e = (D_o/P_o) + g \qquad (4\text{-}5)$$

Thus, the cost-of-equity is the dividend yield plus growth rate of earnings.

For example, in 1972, the electric utility industry yield of 6.5 percent combined with an annual earnings growth rate of 6.0 percent resulted in a 12.5 percent return-on-equity as required by investors. (Ref. 8, 9)

The cost of capital contributed by preferred stock (k_p) can be determined from:

$$k_p = \frac{Fd}{P} \approx d \tag{4-6}$$

where: P = market price of preferred stock

d = contractual preferred dividend rate

F = face value of the preferred stock

The effective interest rate on debt financing (k_ℓ) is defined by the following formula (Ref. 10):

$$P = \sum_{t=1}^{N} \frac{rF\,(1-\tau) + \tau\,(P-F)/N}{(1+k_\ell)^t} + \frac{F}{(1+k_\ell)^N} \tag{4-7}$$

where: P = market price per bond

r = coupon rate of interest on the bond

F = face value of the bond

k_ℓ = effective rate of interest on the bond (after taxes)

N = maturity of the bond, years

τ = marginal tax rate on corporate income

Note that the terms on the right-hand side of the above equation are, respectively, the present value of the after-tax interest expenses and the present value of the principal repayment at maturity. As an approximation the net after tax interest cost is:

$$k_\ell \approx \frac{(1-\tau)\, r\, F}{P} \tag{4-8}$$

The computation of the cost-of-capital for the utility industry based on proportions of 50 percent equity, 50 percent long-term debt and a 40 percent corporate tax rate was made. The resulting cost-of-capital after taxes was 7.42 percent, based upon historical market values.

4.3.3 Escalation and Interest-During Construction (IDC) Model

All base-year investment costs escalate until the start of design and construction at escalation rates appropriate for the individual two-digit accounts. Because of the large time period from the start of design and construction to commercial operation of an electric utility plant both escalation and interest-during-construction (IDC) add significantly to the total capital investment cost for power plants. Consequently, these investment cost components are addressed in considerable detail in the escalation and IDC computer model.

The detailed calculation of escalation and interest-during-construction uses cash flow curves of the type illustrated in Figure 4-2. (Ref. 6) This figure is representative of a nuclear power plant for each two-digit account. The two-digit accounts are in accordance with the standard classification of construction accounts, which represent the major subsystems of the plant. (Ref. 11). The cash flows shown are representative of pressurized water reactor (PWR) type nuclear power plants. However, these can be changed in the program to be representative of other type power plants (Ref. 7). The curves are normalized such that the range for both axes is from zero to one. This normalization simplifies studies in which construction periods and cash flows are altered concurrently. The origin corresponds to the date of placing the order for the nuclear reactor; however, it can be made to correspond to the time of start of construction. These cash flow curves were approximated in the model by three straight line segments as shown in Figure 4-3.

Interest during construction is computed using the cost-of-capital (k) as previously determined. As mentioned before, this rate has averaged about 7.4 percent per year for the 1956 to 1972 time period. This value is assumed for the average in the future.

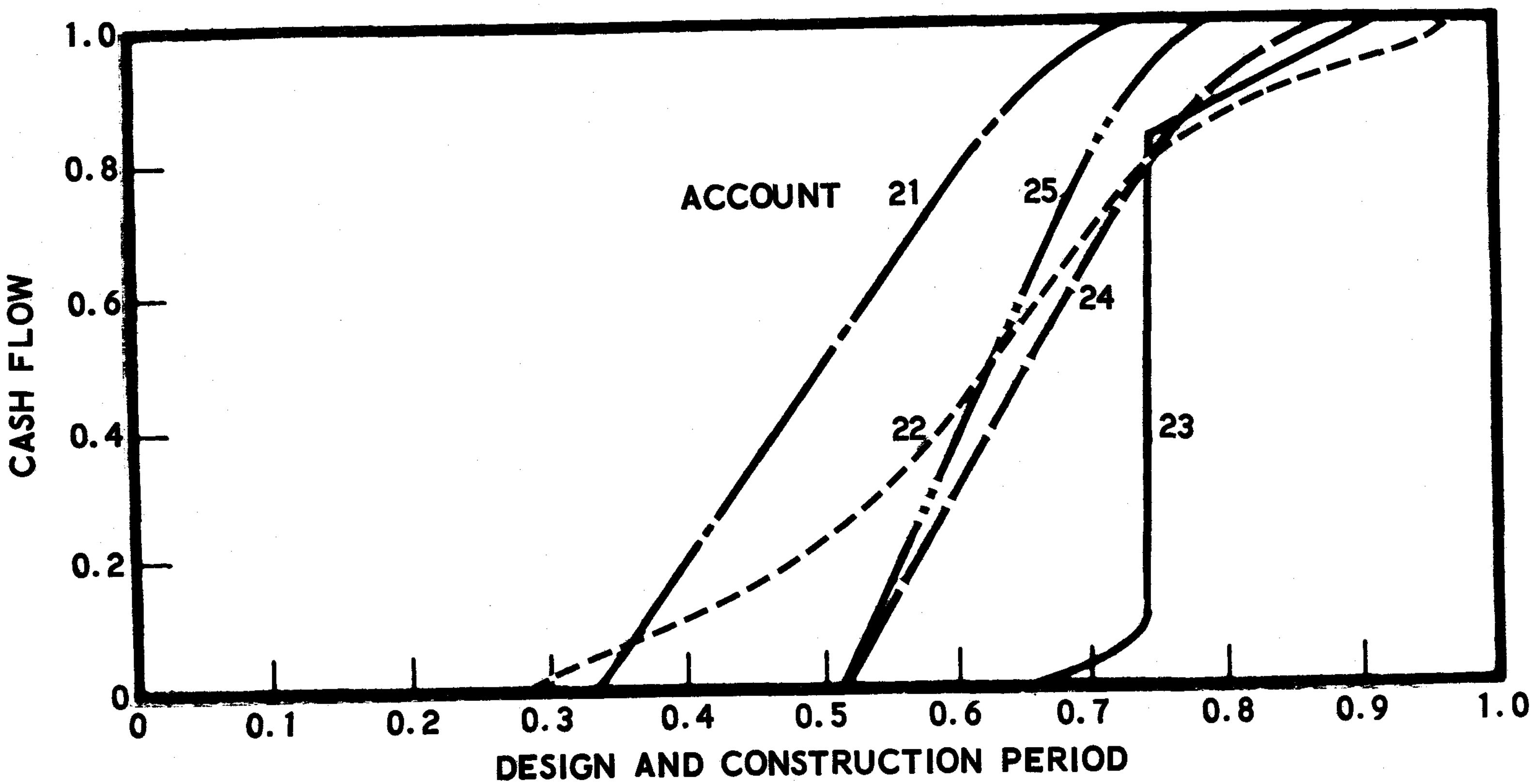

Figure 4-2. Two-Digit Account Cash Flow Curves (Ref. 6)

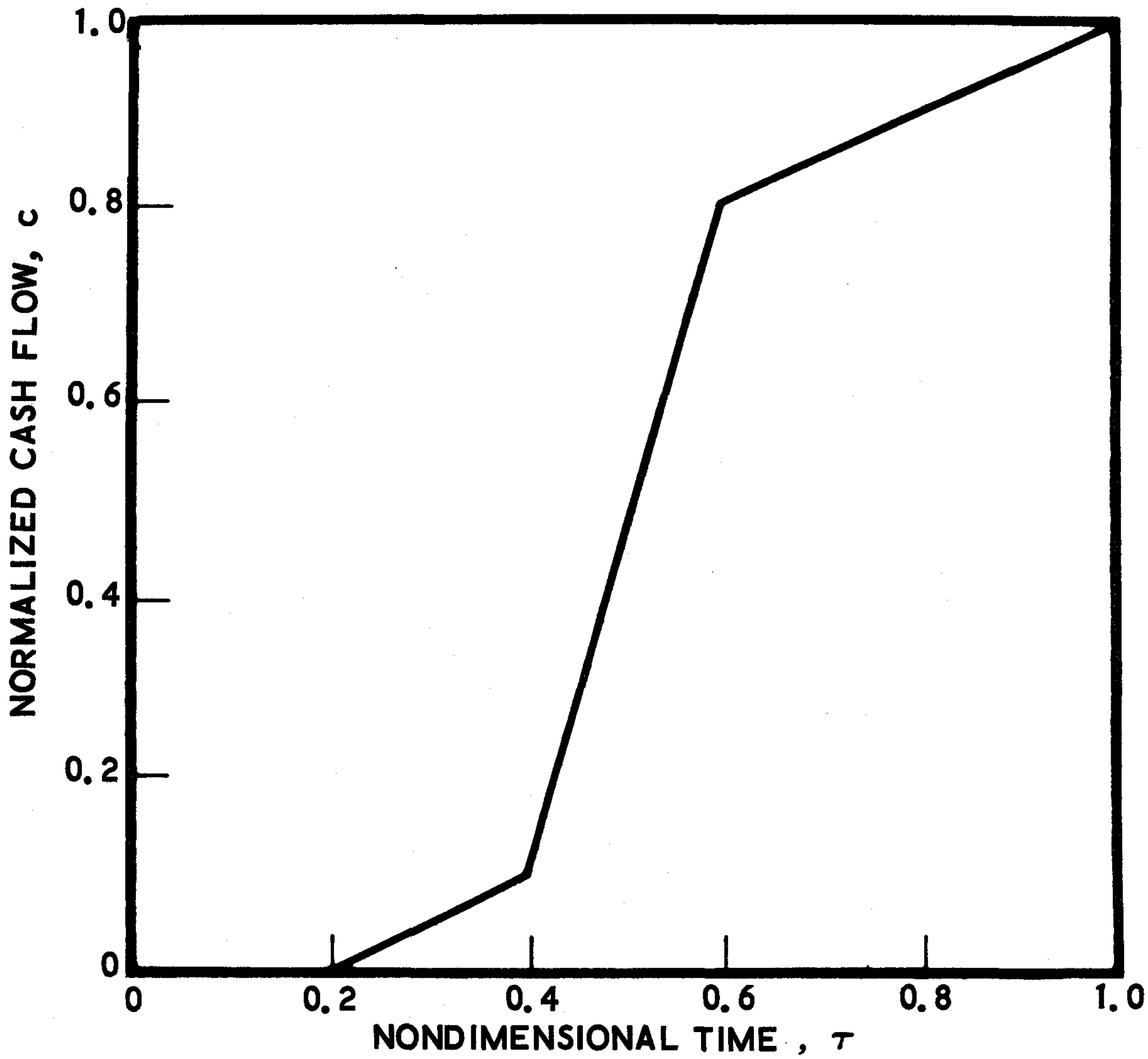

Figure 4-3. Nondimensional Cash Flow and Construction Time (τ)

Total investment cost (INV), interest-during-construction (IDC), and escalation cost (ESC) at time of commercial operation (CO), are determined for each of the two-digit accounts (i, j) by the following relationships:

$$INV_{(i,j)_{co}} = INV_{(i,j)_{sc}} \int_0^1 \left| \frac{dc\ (\tau)}{d\tau} \right| \exp \ \left| e\ (i,j)\ \ T\tau \right| \exp \ \left| kT\ (1-\tau) \right| \ d\tau \tag{4-9}$$

$$IDC_{(i,j)_{co}} = INV_{(i,j)_{sc}} \int_0^1 \left| \frac{dc\ (\tau)}{d} \right| \exp \ \left| kT\ (1-\tau) \right| \ d\tau \ - INV_{(i,j)_{sc}} \tag{4-10}$$

$$ESC_{(i,j)_{co}} = INV_{(i,j)_{co}} - IDC_{(i,j)_{co}} - INV_{(i,j)_{sc}} \tag{4-11}$$

where k is the cost of capital, and $\frac{dc\ (\tau)}{d\tau}$ are the non-dimensional time (τ) derivatives of the individual non-dimensional cash flows c (τ) as shown in Figure 4-3. The escalation rate e (i, j) during the construction time period (T) varies for each account. Total capital investment (TCI) is computed by aggregating all investment accounts. Total IDC_{co} and ESC_{co} are also determined.

Consequently, in this manner with 1972 plant capital investment cost estimates, the total capital investment cost can be calculated for different escalation rates and as a function of time of commercial operation. These total capital investment costs for a particular year of commercial operation are used to compute the total busbar energy costs. Sensitivity to changes in cost-of-capital and escalation rates can be determined using this model.

4.3.4 Power Plant Investment Analysis Model

For a capital investment to be economically attractive, the annual net cash inflows during the operating lifetime of the plant, when discounted at the cost-of-capital, must equal or exceed the total capital investment. These net cash inflows are determined from the pro-forma annual income statements by deducting all cash outflows from the total busbar energy cost allocated to the plant. Consequently, the total busbar energy cost for a typical plant must be sufficient to recover the total capital investment at the year of commercial operation.

The economic relations for this model are shown in Appendix B. The computer routine developed as part of the economic analysis methodology will permit escalation of each component of the pro-forma income statements at different rates, and incorporates straight line, sum-of-the-year-digits, or double-declining depreciation of plant and equipment.

The value of operating cost categories (fuel, insurance, other operating expenses) are determined by escalating the base year input cost (e.g., 1972) by the appropriate account escalation rate. In the case of fuel a different escalation rate may be utilized up to year of commercial operation. In addition two escalation rates can be utilized for fuel during the plant operating life time period. The computer program also permits the economic analysis of hybrid solar plants, by inclusion of a fractional fuel cost.

Consequently, the effect of many parameters, such as escalation rates of investment accounts and fuel costs can be evaluated, as well as the impact of time of construction, cash flows during construction, useful plant life, and the cost of capital. These system cost sensitivities are essential in determining the economic leverage for the systems design.

After having determined the required total busbar energy cost, the computer program will print out a pro-forma income statement and a breakdown of total busbar energy cost into its various components for any year of commercial operation.

Vice versa, given the total busbar energy cost for a future (e.g. 1990) time period, such as from FPC projections, an equivalent total capital investment can be imputed for solar power plants which are economically competitive. The imputed total solar capital investment becomes the design goal towards which solar power plants must be designed in order to compete economically.

The solar system parameter variations, subject to design constraints, will allow the determination of the cost sensitivity of the total solar system to individual design parameter and option changes, using the above described computer program. From this sensitivity analysis, it is possible to determine the most competitive solar system and determine its economic attractiveness in comparison with conventional nuclear and fossil power plants.

4.4 POWER PLANT CAPITAL COST ESTIMATES

The comparative 1990 capital cost estimates of illustrative 1,000 MWe base-load solar, nuclear, and fossil plants are shown in Table 4.5.

The solar thermal conversion plant data are for a 1,000 MWe base-load plant, as described previously, with a collector field of 30 Km^2 and a 12 hour storage capacity. (Ref. 4)

The representative conventional plants are a pressurized water nuclear reactor, and a low-sulphur-coal fossil plant, respectively, each with a base-load rating of 1,000 MWe (Ref. 12). A 400 MW combined cycle plant is also shown and will be discussed subsequently in connection with future intermediate load applications (Ref. 13).

The capital costs are shown by investment account (in $/KWe) in accordance with the account structure used by the Federal Power Commission. Regional and local factors such as geography, geology, water availability, land prices, etc., could cause capital costs to vary from the information presented. These cost estimates are believed to be appropriate for comparative purposes.

Two accounts were added specifically for solar plants, one is the solar collectors/thermal transport account, which includes storage tanks, and the other is a thermal storage materials account.

Also added are allowances for environmental protection systems, and cooling tower variations, which apply as appropriate.

All components of the total capital investment cost accounts are in 1972 dollars, including contingency, spare parts, and indirects. The 1990 cost is the sum of the 1972 cost, the escalation to start of design and construction,

Table 4-5. Power Plant Capital Cost Estimates
($/KWe)

	SOLAR BASE LOAD	NUCLEAR (PWR)	FOSSIL (coal)	COMBINED CYCLE
LAND	10	1	1	
STRUCTURES AND FACILITIES	38	38	25	
SOLAR COLLECTORS/TRANSPORT	905	--	--	
THERMAL STORAGE MATERIAL	140	--	--	
HEAT EXCHANGER/REACTOR/BOILER	30	59	62	
TURBINE PLANT EQUIPMENT	52	68	52	
ELECTRIC PLANT EQUIPMENT	14	16	14	
MISC PLANT EQUIPMENT	4	5	4	
ALLOWANCE FOR COOLING TOWERS	12	12	10	
SO_2 REMOVAL SYSTEM	--	--	33	
ZERO RADWASTE SYSTEM	--	4	--	
TOTAL DIRECT COST	1205	203	201	
CONTINGENCY ALLOWANCE	104	13	14	
SPARE PARTS ALLOWANCE	9	1	1	
INDIRECT COSTS	53	53	45	
TOTAL CAPITAL INVESTMENT (1972)	1371	270	261	163
ESCALATION TO START OF DESIGN AND CONSTRUCTION	518	131	140	88
TOTAL AT START OF CONSTRUCTION	1889	401	401	251
INTEREST DURING CONSTRUCTION	226	63	49	31
ESCALATION DURING CONSTRUCTION	270	108	78	49
TOTAL COST AT YEAR OF COMMERCIAL OPERATION (1990 dollars)	2385	572	528	330

the escalation which continues during construction, and the interest during construction are functions of the case expenditure flow rate for each investment account.

Illustrative solar thermal conversion power plant capital cost estimates are shown in Table 4.6 for base, intermediate, and peaking load applications, respectively. Characteristics of each of these solar plants are those described and analyzed in the previous mission/system analysis. Each plant has a turbo-generator rating of 1,000 MWe, and the numbers 30/12; 20/6; and 10/3, refer to the collector areas (in Km^2) and storage capacities (in hours).

The capital investment costs, in 1972 dollars, as shown by the various accounts, when combined with the escalation and interest-during-construction costs, result in the total capital investment cost of these plants at the year of commercial operation (1990).

4.5 OPERATING COSTS

The principal component of operating costs for conventional power plants is fuel. In addition, recent rapid escalation in fuel prices has increased the importance of fuel costs in determining total busbar energy costs. Other operating costs are for operation, maintenance, and insurance.

4.5.1 Nuclear Fuel Costs

For nuclear power plants fuel cycle costs, including carrying charge, were 2.13 mills/Kwh in 1972. This included a direct fuel cost of 1.5 mills (Ref. 14), while the additional fuel cycle costs are carrying charges of 42 percent (Ref. 15).

Table 4-6. Solar Power Plant Capital Cost Estimates
($/KWe)

COLLECTOR AREA (KM^2)/THERMAL STORAGE (hr)	BASE LOAD 30/12	INTER-MEDIATE 20/6	PEAKING 10/3
LAND	10	7	3
STRUCTURES AND FACILITIES	38	38	38
SOLAR COLLECTORS*/TRANSPORT	905	601	300
THERMAL STORAGE MATERIAL**	140	70	35
HEAT EXCHANGER	30	30	30
TURBINE PLANT EQUIPMENT	52	52	52
ELECTRIC PLANT EQUIPMENT	14	14	14
MISC PLANT EQUIPMENT	4	4	4
ALLOWANCE FOR COOLING TOWERS	12	12	12
TOTAL DIRECT COST	1205	828	488
CONTINGENCY ALLOWANCE	104	13	42
SPARE PARTS ALLOWANCE	9	6	4
INDIRECT COSTS	53	44	40
TOTAL CAPITAL INVESTMENT (1972)	1371	891	574
ESCALATION TO START OF DESIGN AND CONSTRUCTION	518	371	226
TOTAL AT START OF CONSTRUCTION	1889	1262	800
INTEREST DURING CONSTRUCTION	226	160	96
ESCALATION DURING CONSTRUCTION	270	193	119
TOTAL COST AT YEAR OF COMMERCIAL OPERATION (1990 dollars)	2385	1615	1015

*Collector cost = $25/M^2$

**Thermal Material cost = $12/KW/hr

4.5.2 Fossil Fuel Costs

Fossil fuel costs for power plants serving Southern California are shown in Table 4.8. These 1972 fuel costs include transportation and represent fuels with a low sulphur content (Coal 1%).

A study of future nuclear fuel cycle cost was made on the basis of forecasted future uranium prices and a projected escalation rate (4%) for nuclear fuel enrichment, fabrication, and reprocessing. The future demand for uranium ore (U_3O_8) was obtained by using industry forecasts of uranium requirements to 1985 and AEC forecast of nuclear generating capacity (and associated fuel requirements) beyond 1985 (Ref. 15, 16). Commercial availability of fast breeder reactors was assumed for the 1990 time period and beyond. The supply of uranium ore (U_3O_8) at various prices per pound was obtained from AEC publications (Ref. 15, 16). The resulting fuel cycle costs are shown in Table 4.8. The average escalation rate over the time period 1972 to 2000 is 5.7 percent/year.

The cost figure for coal is for Northeast Arizona strip-mined coal and includes shipping via slurry pipeline or unit train to Southern Nevada or Northwest Arizona. The cost corresponds to a mine-mouth price of $3.32 per metric ton. Natural gas prices for imported liquified natural gas (LNG), coal gaisification from New Mexico, and 1972 delivered domestic natural gas (limited quantity), were averaged to produce the composite gas fuel cost figure of $0.67/million Btu.

Fuel escalation rates were developed for coal and gas but not for oil, as current oil prices already preclude its consideration for new power plants. The delivered cost of coal was disaggregated into two components, transportation and the mined cost of the coal. The transportation component was assumed to increase at the same rate as the general price level (4%/year). The price of western coal was assumed to escalate at an

Table 4.7

Fossil Fuel Costs

(1972 Dollars)

Fuel	$/Million Btu	Mills/Kwh*	Comments
Coal (Ref. 17)	$ 0.15	1.31	Strip Mined Arizona Coal
Natural Gas (Ref. 18, 19)	$ 0.67	5.72	Average of Several Sources

*40% Thermal Efficiency

Table 4.8

Nuclear Fuel Costs
(Mills/Kwh)

(Current Dollars)

Year	Fabrication and Enrichment	U_3O_8	Carrying Cost	Total
1972	1.04	.46	.63	2.13
1980	1.42	.66	.87	2.94
1990	2.11	1.89	1.68	5.68
2000	3.12	4.16	3.06	10.34

increasing rate. Shown in Table 4.9 are the escalation rates assumed for western coal and the resulting combined escalation rates for delivered coal.

By comparison in the time period 1967 to 1973 the index of coal prices (mostly Eastern Deep-Mined Coal) increased 13.5%/year (Ref. 1, 2).

The escalation rate for natural gas could be determined by the proportion of total gas supply contributed by each of the sources of varying price: imported LNG, coal gasification, and conventional domestic natural gas. However, given the unavailability of figures on the relative proportions in the future, a 7.0% per year escalation rate was assumed. Because of the short supply projected for natural gas, this fuel was not assumed except in the combined cycle units. Even there, little of this fuel is actually expected to be used in Southern California in the future.

4.5.3 Other Operating Costs

Data on other operating costs, operation and maintenance (O&M) and insurance, were derived from an Oak Ridge National Laboratory (ORNL) publication and adjusted to 1972 dollars (Ref. 20). The ORNL cost data are for base-power plants and includes cost estimates for the operation of various environmental protection systems. The O&M cost estimate for solar plants was based on adjusting the fossil plant cost data. Table 4.10 shows the O&M cost estimates.

Table 4.11 shows the insurance and property tax cost estimates. The insurance costs were obtained from ORNL (Ref. 20). The insurance rate for the solar subsystem is assumed. The property tax rates are based on the assumption of a remote inland site. A plant in such a site would be

Table 4.9

Coal Escalation Rates

Time Period	Mine Mouth Coal Price Escalation Rate (%/Yr)	Delivered Coal Price Escalation Rate (%/Yr)
1972-1990	8%	6.7%
1990-2000	10%	8.2%

Table 4.10

Operation & Maintenance Cost Estimates (1972 Dollars)
1000 MWe Base Power Plants
($/KWe)

Cost Category	Oil	Coal	Nuclear	Solar
O&M Basic	3.1	3.5	4.1	3.8
SO_2 Removal	*	1.9	-	-
Dry Towers	.1	.1	.1	.2
Zero Radwaste	-	-	.2	-
O&M Solar	-	-	-	3.2
N_{ox} Control	1.9	1.9	-	-
Fly Ash	-	.1	-	-
Environmental Monitoring	.1	.1	.1	.1
Total	5.2	7.7	4.5	7.3

*Fuel with sulphur content of .3%

Table 4.11

Insurance & Property Tax
(Percent of Fixed Investment)

	Oil	Coal	Nuclear	Solar
Insurance (Basic Part)	.20	.20	.50	.15
Insurance (Solar Part)	-	-	-	.05
Property Tax	.25	.25	.25	.25
Total	.45	.45	.72	.45

free of both municipal and school taxes and subject only to county property tax rates. The county tax rate is assumed to be \$1.00/\$100 of assessed valuation where property (excluding inventories) is assessed at 25 percent of market value.

4.6 ECONOMIC ANALYSIS RESULTS

An economic analysis was made of solar power plants for base, intermediate, and peaking load applications. For comparison, conventional (nuclear and/or fossil) power plants were also studied, using the economic analysis methodology described in Section 4.3. All power plants were examined in terms of a 1990 year of commercial operation and using the data standards shown previously.

The capital investment costs are shown in Tables 4.6 and 4.7 for solar, nuclear, coal, and combined cycle power plants. The solar, nuclear, and coal plants are 1000 MW(e) base load plants. The combined cycle is a 400 MW power plant for intermediate and peaking load application.

The contingency allowance for solar power plants is obtained by a 7 percent contingency allowance on the conventional portion and a 10 percent allowance on the solar portion. The 7 percent figure is the contingency allowance used for fossil power plant capital costs.

Separate escalation rates for land, plant, and materials here used where materials designate solar plant thermal storage materials. Plant is total capital investment cost exclusive of land and materials. For the plant, a weighted average composite escalation rate was developed from the individual investment account escalation rates and applied to total plant cost. These composite plant escalation rates are 3.82 percent for nuclear, 3.63 percent for coal, and 2.95 percent for solar plants.

The time period assumed for design and construction was 7-1/2 years for nuclear plants and 6 years for solar and fossil plants. The interest during construction was calculated using the cost-of-capital (7.4 percent).

4.6.1 Base-Load Solar Plant Economic Evaluation

The total busbar energy cost was determined for the alternative 1000 MWe base-load solar thermal conversion plant configurations with characteristics and parametric performance described in the previous mission/system analysis.

The results of the economic evaluation are shown in carpet plots in Figure 4-4.

The first year of commercial operation total busbar energy costs (in 1991 dollars) are shown parametrically for various collector area and storage capacity combinations. The upper carpet plot reflects a $25/m^2 collector area cost and a $12/Kwh storage cost, while the lower carpet plot is for the same storage cost and a lower $15/m^2 collector area cost.

As can be seen from this chart, for base-load application the lowest burbar energy cost (~~20~~ 10 mills/Kwh, 1991 dollars) is for a solar plant with a 30 Km^2 collector area and 12 hours storage capacity.

The wide band at the bottom of the chart is the busbar energy costs for 1000 MWe conventional (nuclear and fossil) power plants. These busbar energy costs were computed using the same economic analysis methodology

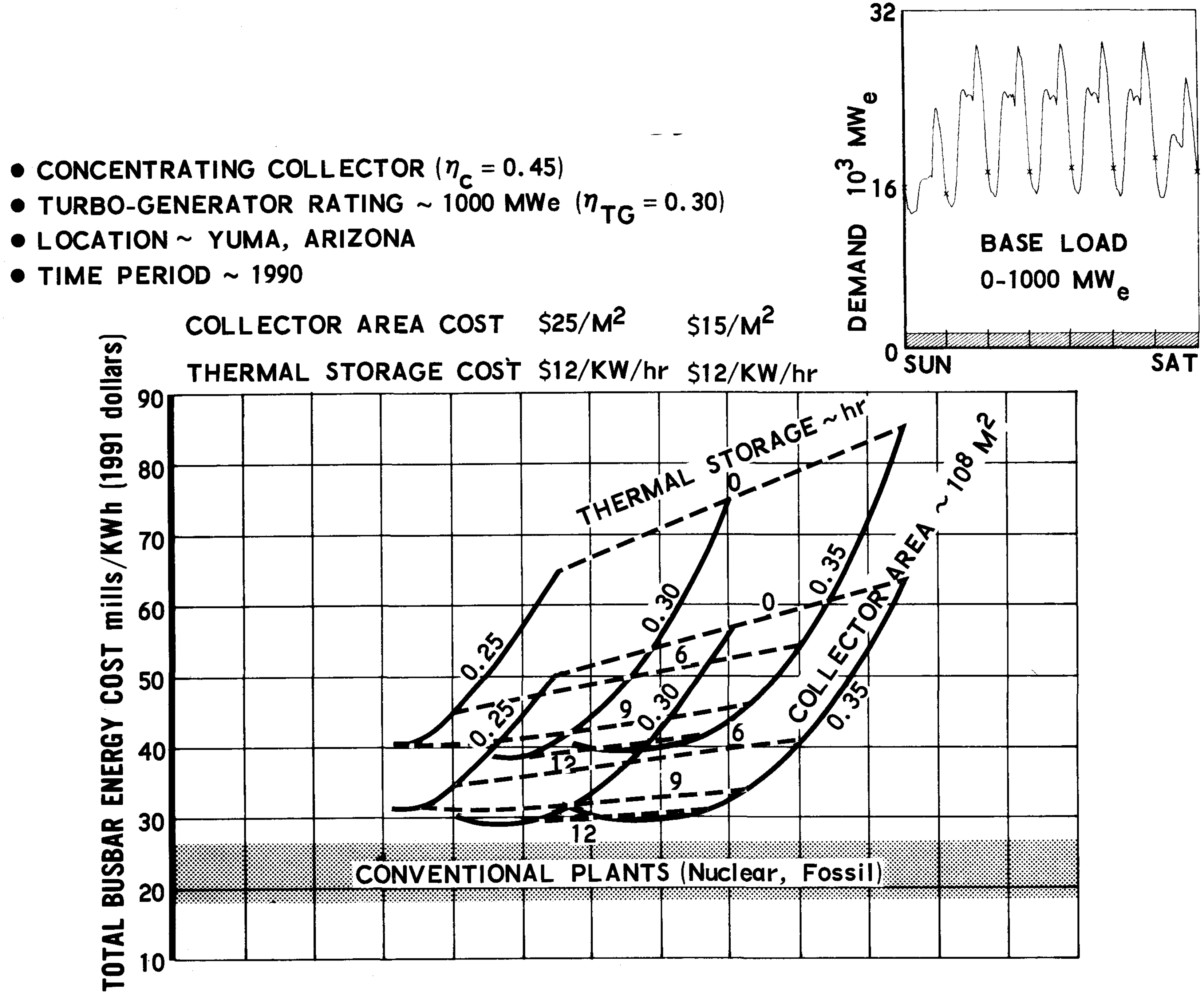

Figure 4-4. Base Load Solar Thermal Conversion Power Plant Total Busbar Energy Cost

and data standards as used for the solar power plants. The width of the conventional power busbar energy cost band reflects both nuclear (PWR) and fossil (coal) power plants with variations in the assumed plant capacity factors of 60 percent to 80 percent.

4.6.2 Comparative Base-Load Busbar Energy Costs

The comparative total busbar energy costs (in 1991 dollars) for representative 1000 MWe base-load solar nuclear, and fossil power plants are shown in Figure 4-5.

Shown is the total busbar energy cost in terms of fixed costs (cost of money, depreciation and insurance, and taxes) and variable costs (fuel and other operating costs).

The solar plant depicted in this chart is based on a unit collector cost of $\$25/m^2$ (1972 dollars) and the plant capacity factor was determined by system simulation for a field size of 30 Km^2 and 12 hours storage capacity. The capacity factors for the fossil and nuclear plants were assumed and do not imply that the solar plant will necessarily operate at a higher capacity factor. The investment costs for the solar, fossil, and nuclear plants, shown at the bottom of the figure, are those shown earlier in Table 4.5.

Included in the solar plant busbar energy cost is an allowance for backup capacity. This is the cost for maintaining sufficient conventional backup capacity to achieve equal utility system reliability as for a conventional 1000 MWe plant. The rationale for and the amount of backup capacity required was determined previously in the section discussing margin analyses.

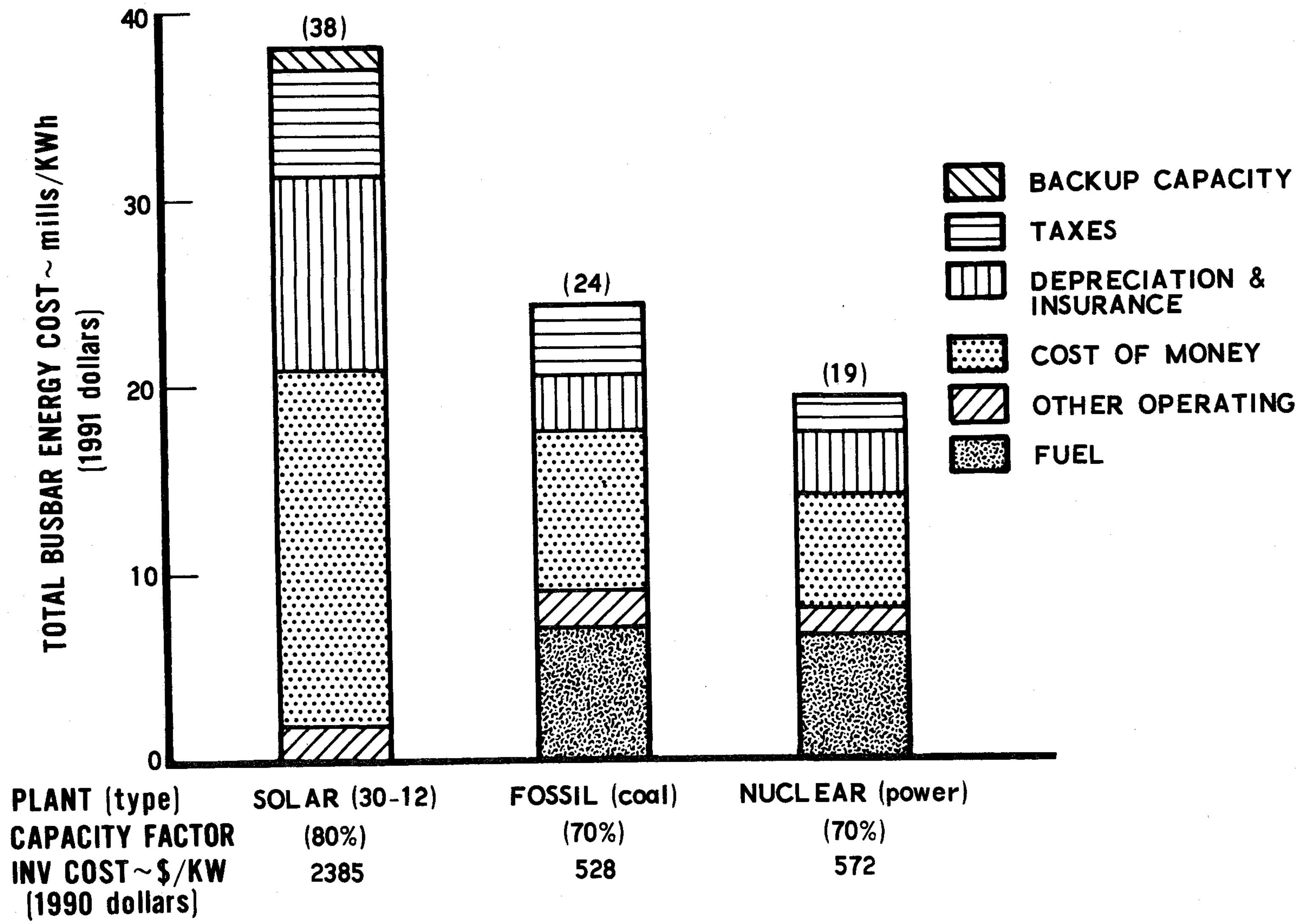

Figure 4-5. Total Busbar Energy Cost
Base Load Power (1991)

4.6.3 Intermediate and Peaking Load Solar Plant Evaluation

The total busbar energy costs for alternative 1000 MWe solar thermal conversion power plants for intermediate and peaking load applications are shown in Figures 4-6 and 4-7, respectively.

The results are shown parametrically for various combinations of collector area and storage capacity.

The upper and lower carpet plots reflect a $\$25/m^2$ and $\$15/m^2$ unit area collector cost, respectively, both having a thermal storage cost of \$12/Kw/hr.

Included in the intermediate and peaking-load solar plant busbar energy costs are cost credits allowed for the additional conventional fuel displacement when operating outside the designated demand range, as discussed in the system analysis section (Figures 2-13 and 2-16). No capacity displacement was assumed for this additional energy displacement.

For intermediate load application, a solar plant with a 20 Km^2 collector area with 6-hour storage capacity has the lowest total busbar energy cost.

In the case of peaking load applications, the minimum solar plant busbar energy occurs with a 12 Km^2 collector area, and 3 hours of storage capacity.

The fossil-fuel busbar energy costs for intermediate and peaking power plants, as shown by the wide band in Figures 4-6 and 4-7, were based on a 400-MWe combined cycle gas turbine plant using natural gas as fuel. A fuel cost (in 1972 dollars) of \$0.67 per million Btu was assumed, with an escalation rate of 7 percent per year. The busbar energy costs for these intermediate and peaking fossil plants are illustrative only and are not necessarily the minimum costs attainable.

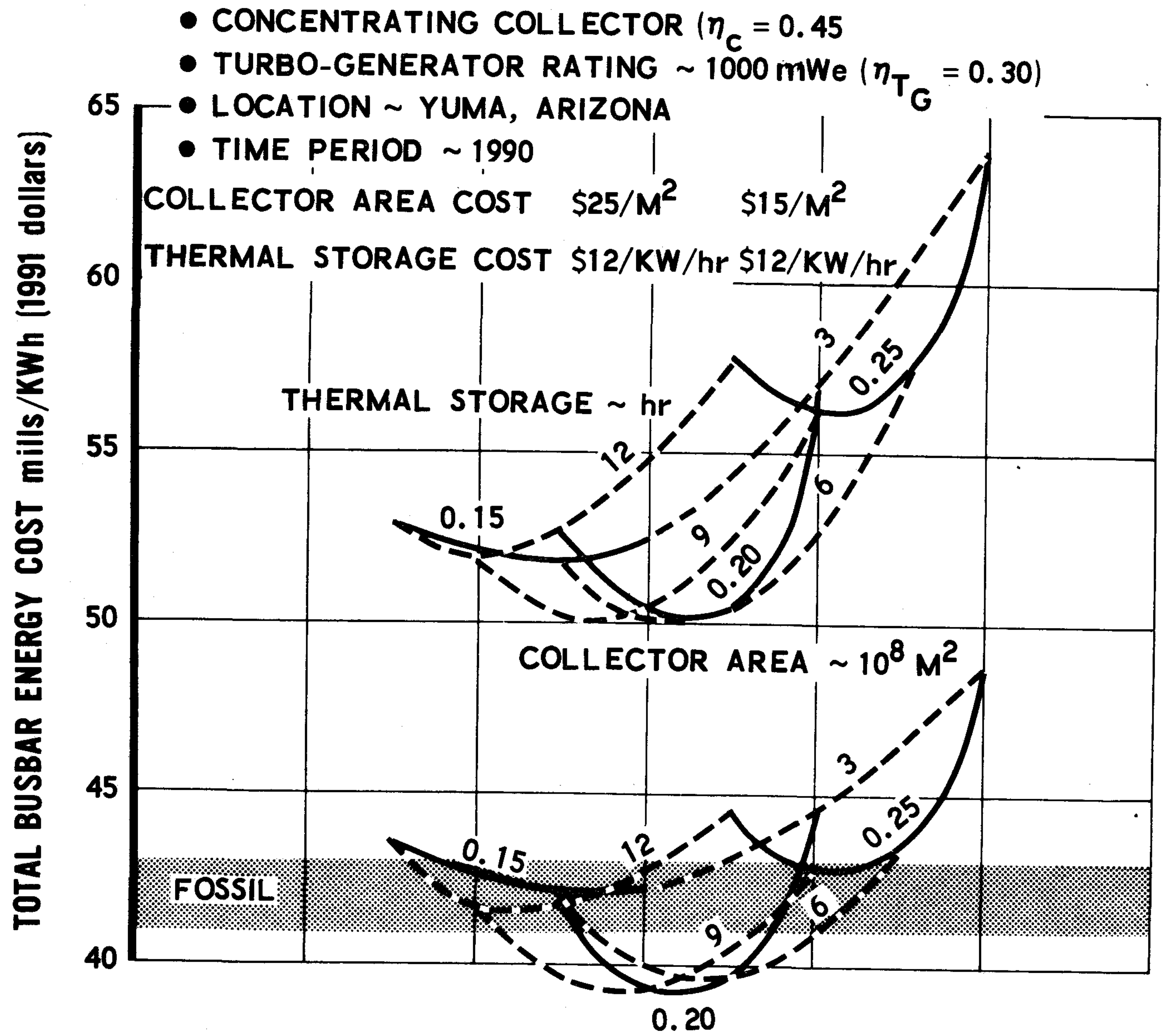

Figure 4-6. Intermediate Solar Thermal Conversion Power Plant Total Busbar Energy Cost

- CONCENTRATING COLLECTOR ($\eta_c = 0.45$)
- TURBO-GENERATOR RATING ~ 1000 mWe ($\eta_{T_G} = 0.30$)
- LOCATION ~ YUMA, ARIZONA
- TIME PERIOD ~ 1990

COLLECTOR AREA COST	$25/M^2	$15/M^2
THERMAL STORAGE COST	$12/KW/h	$12/KW/hr

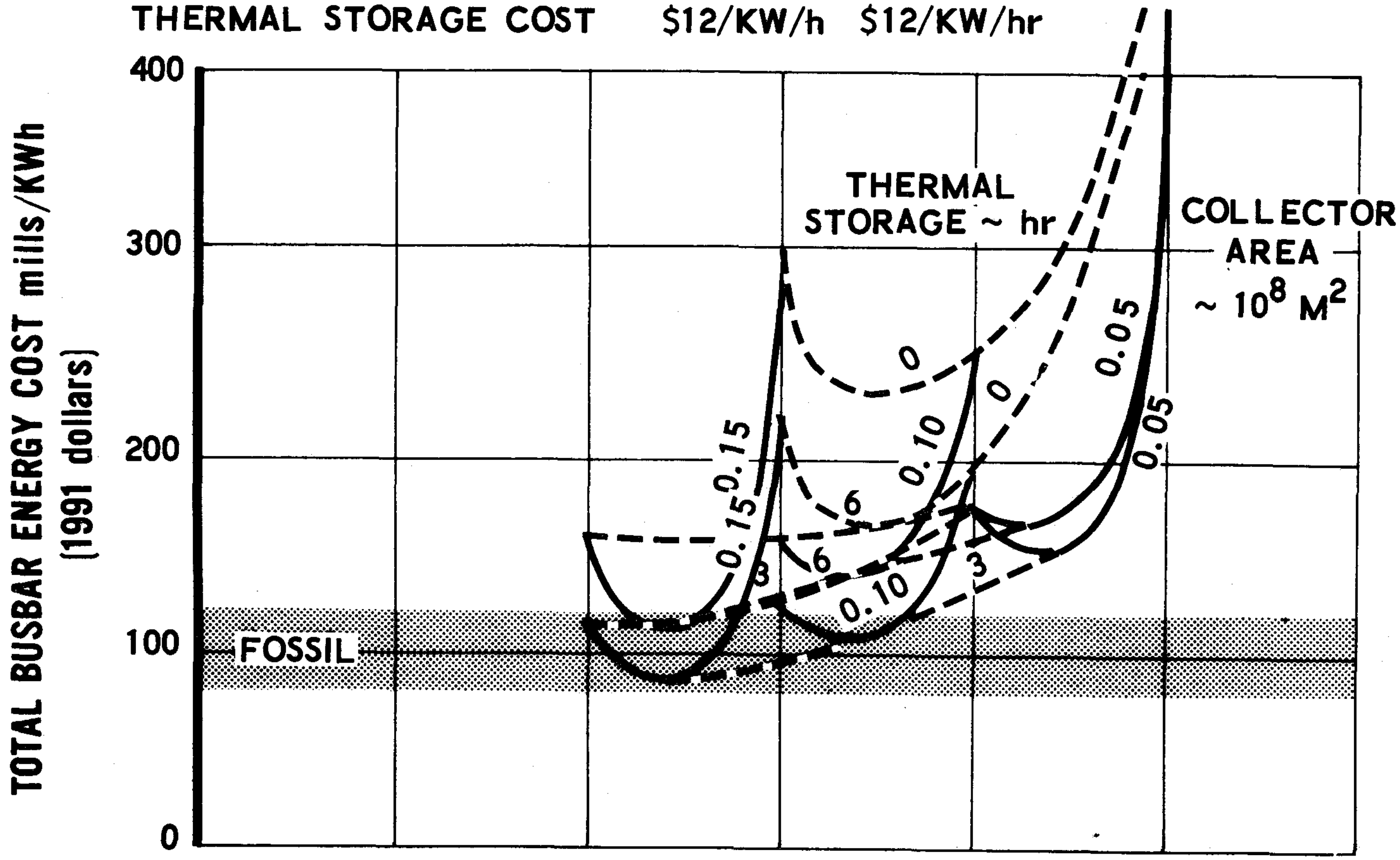

Figure 4-7. Peaking Solar Thermal Conversion Power Plant Total Busbar Energy Cost

4.6.4 Comparative Intermediate and Peaking Load Busbar Energy Costs

The comparative total busbar energy costs (in 1991 dollars) for representative intermediate and peaking load solar and conventional power plants are shown in Figures 4-8 and 4-9, respectively.

The total busbar energy cost is shown in terms of fixed charges and variable costs. For intermediate and peaking solar plants, in addition to the additional fixed charge to account for conventional backup capacity required, an energy displacement credit is shown to account for the additional intermediate and base-load energy (fuel) displacement. For this additional energy displacement, outside the basic intermediate or peaking-demand range, no additional capacity displacement was assumed.

The capacity factors shown on these charts are for the designated demand range only, while the numbers in brackets include this additional energy displacement.

4.6.5 Cost Sensitivity Analysis

Because of the uncertainty in cost estimates of the solar-plant-peculiar subsystems, this preliminary Cost Sensitivity Analysis was performed. This analysis examines the cost impacts of various design and economic parameters on representative base, intermediate, and peaking-load solar plants. Shown in Table 4.12 is the impact on total busbar energy cost (in mills/Kwh, 1991 dollars) of changes in four parameters:

- $\$/m^2$ increase in unit area collector cost
- Percent decrease in collector efficiency
- Kwh increase in thermal storage cost
- Percent of required backup capacity.

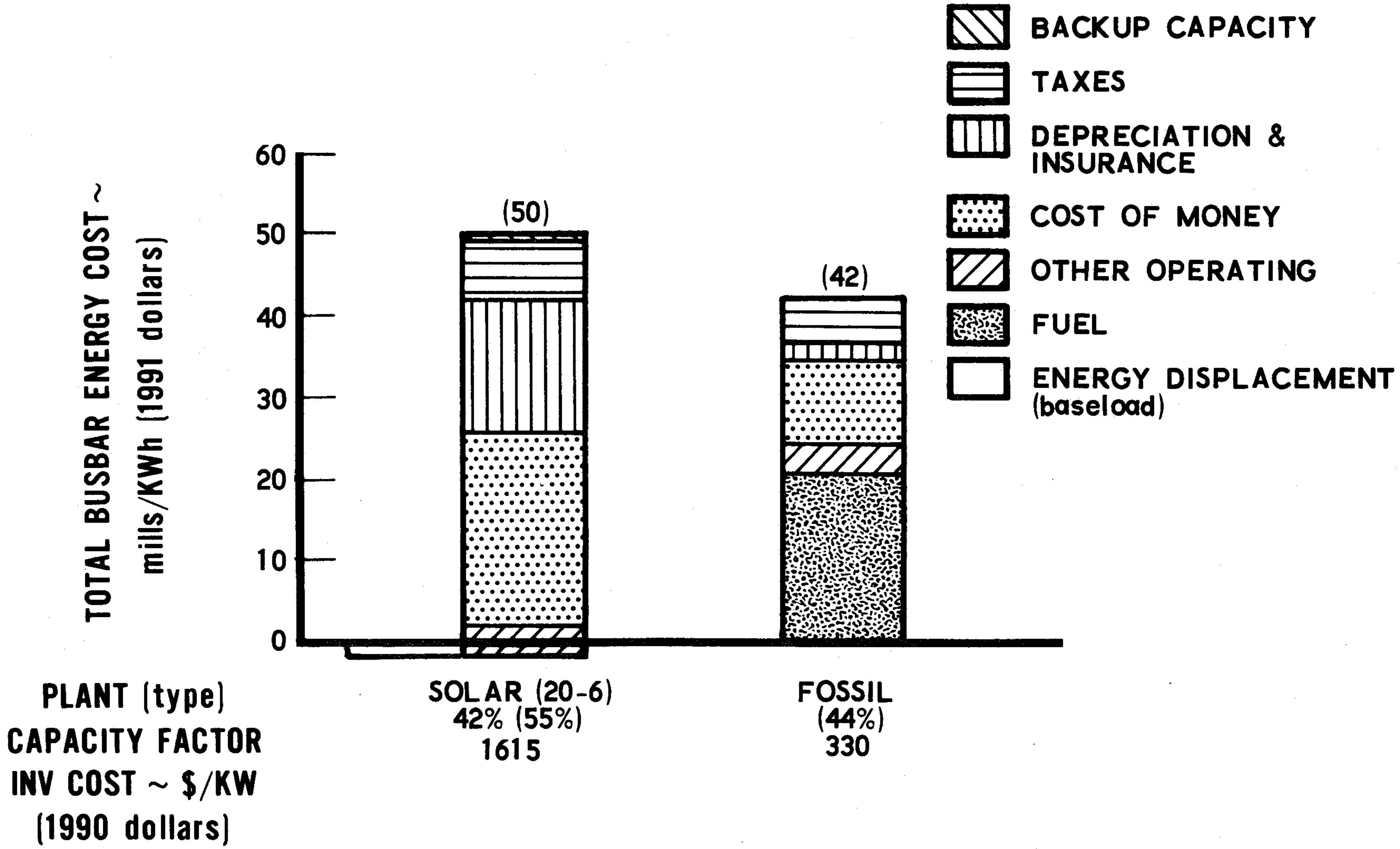

Figure 4-8. Total Busbar Energy Cost
Intermediate (1990)

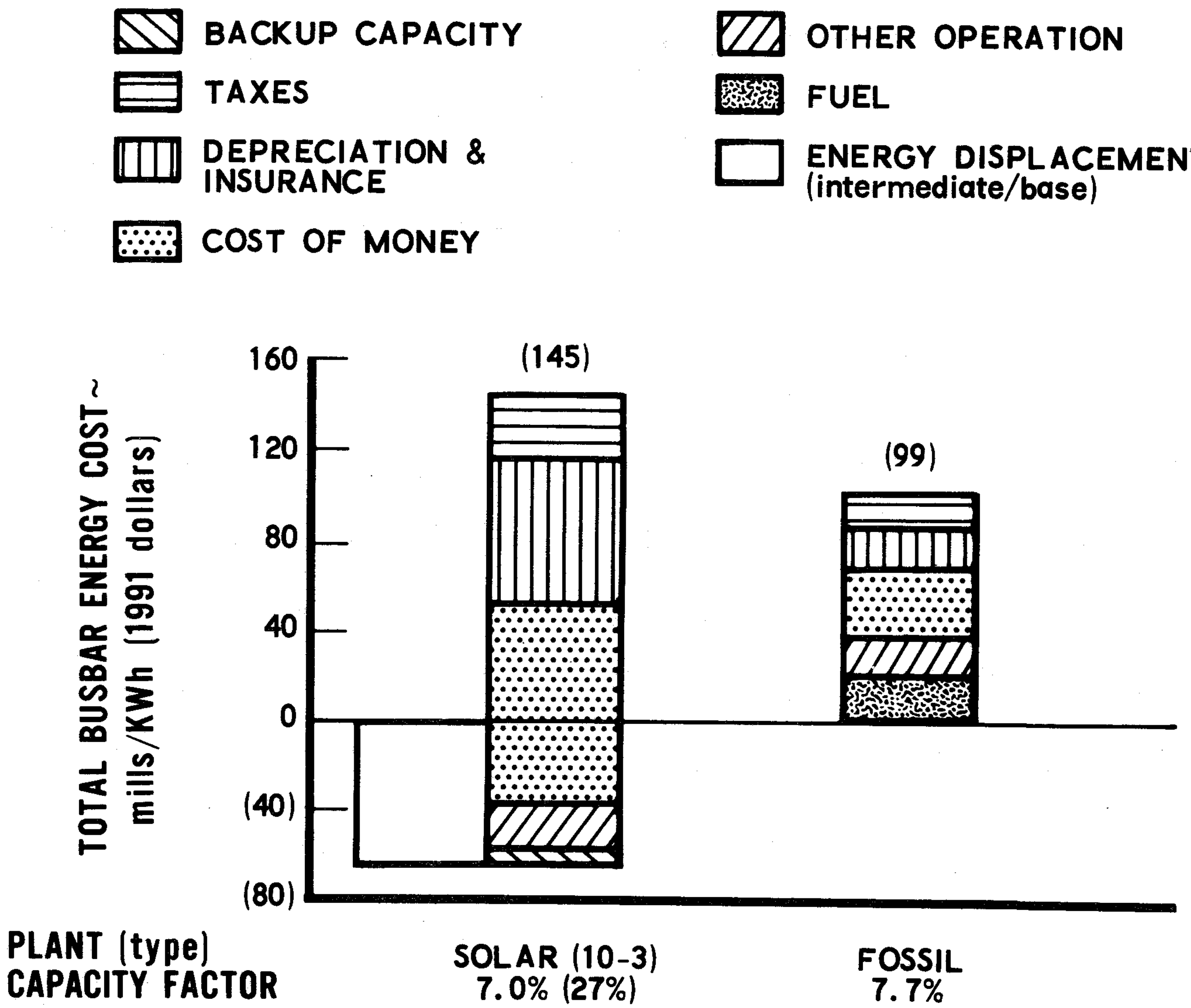

Figure 4-9. Total Busbar Energy Cost
Peaking (1990)

Table 4-12. Cost Sensitivity Analysis
(1991 Dollars)

SOLAR PLANT	TOTAL BUSBAR ENERGY COST (mills/kWh)			
	UNIT COLLECTOR AREA COST ($/m^2)	% COLLECTOR EFFICIENCY	UNIT STORAGE COST ($/kW/hr)	% BACKUP CAPACITY
BASE LOAD COLLECTOR AREA - 30 km^2 THERMAL STORAGE - 12 hr CAPACITY FACTORS - 0.793	0.79	0.20	0.23	0.07
INTERMEDIATE COLLECTOR AREA - 20 km^2 THERMAL STORAGE - 6 hr CAPACITY FACTOR - 0.418	0.97	0.24	0.21	0.13
PEAKING COLLECTOR AREA - 10 km^2 THERMAL STORAGE - 3 hr CAPACITY FACTOR - 0.070	2.97	0.74	0.65	0.76

For example, the upper-left box shows that for the illustrative base-load solar plant, a \$1.00/m^2 increase in collector cost increases the 1991 busbar energy cost by 0.79 mills/Kwh.

5. SUMMARY

In summary, this initial mission analysis effort has been productive. An operational methodology has been developed to assess the potential of solar thermal-conversion mission and systems in a realistic operating environment. This methodology was successfully tested with a parametric technical and economic evaluation of representative solar plants in a total-electric-power grid.

As a result of these efforts, a number of computer programs have been developed which permit the assessment of solar plants on a consistent basis.

- A standard insolation data base was developed for eight stations in Southern California and one in Albuquerque, New Mexico. This standard data base is available for all NSF contractors in the Solar Thermal Conversion Program.

- An electric-power demand forecast model was developed to permit a detailed hourly demand forecast for the time period 1980 to 2000.

- Several margin analysis routines were developed to assess the potential for capacity displacement of solar-power plants when required to deliver electric service with the same reliability at conventional power plants.

- The modular system-simulation program has the ability to perform system simulations on an hour-by-hour basis for an entire year. With this method, the technical performance of alternative missions and systems can be evaluated parametrically using hourly insolation and demand inputs.

- Finally, the generation and environmental impact model, operating essentially as an utility dispatch model, can assess in detail the fuel and investment-capital requirements as well as the environmental impacts of alternative integrated power systems.

The interaction of these computer routines are shown in Figure 5-1. All of the above computer models are operational and have been successfully applied, with the exception of the dispatch model which is presently under development.

These mission and system analysis methodologies were applied to parametrically evaluate the power plant performance of alternative solar system configurations in different operational modes. The assessment included the capacity displacement, energy displacement, and capacity factors of these plants, combined with the economic analysis to compare these solar with conventional power plants.

A more detailed evaluation of alternative solar systems will become possible when better inputs become available from various system study contracts now underway for the NSF.

In principle, the methodology developed can be applied to other types of solar thermal-conversion systems, such as the central receiver concept and flat-plate collector systems. However, the subsystem descriptions would have to be modified in the systems analysis to more accurately reflect the specific characteristics of these subsystems.

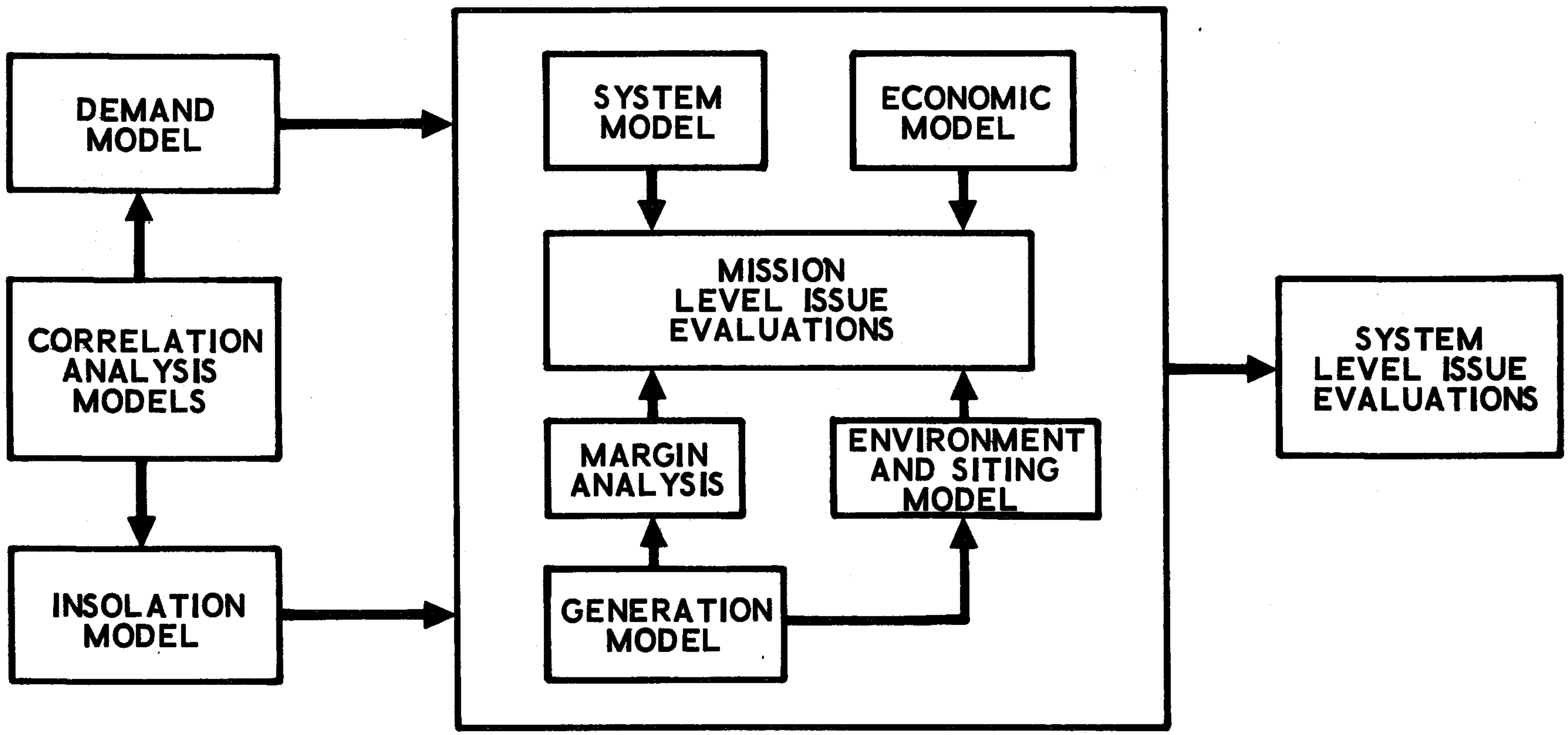

Figure 5-1. Computer Routines Interactions

APPENDIX A
INTEGRATION LIMITS FOR COLLECTOR TRACKING AND GEOMETRY MODEL

Figure A.1 illustrates the various quantities involved in the set of equations which comprises the algorithm for the determination of the limits of integration due to the boundary of the plane of the aperture. The arc length DS represents that corresponding to the limit of integration for that particular value of γ. The azimuth is measured positive from the south towards the west and negative towards the east.

The basic algorithm for the calculation of the limits of integration for an azimuthal angle γ is presented below for completeness.

$$\cos \overline{RD} = \cos\varphi \sin\beta - \sin\varphi \cos\beta \cos\alpha \tag{A-1}$$

$$\sin \overline{BDR} = \frac{\sin\alpha \sin\varphi}{\sin \overline{RD}} \tag{A-2}$$

$$\angle \overline{RDE} = \gamma - \angle \overline{BDR} \tag{A-3}$$

$$\sin \overline{BRD} = \frac{\sin\alpha \cos\beta}{\sin RD} \tag{A-4}$$

$$\angle \overline{DRS} = 90^{\circ} - \angle \overline{BRD} \tag{A-5}$$

$$\cos \overline{RSD} = -\cos \overline{DRS} \cos \overline{RDE} + \sin \overline{DRS} \sin \overline{RDE} \cos \overline{RD} \tag{A-6}$$

$$\sin \overline{DS} = \frac{\sin \overline{DRS} \sin \overline{RD}}{\sin RSD} \tag{A-7}$$

$$\sin \overline{RS} = \frac{\sin \overline{RDS} \sin \overline{RD}}{\sin RSD} \tag{A-8}$$

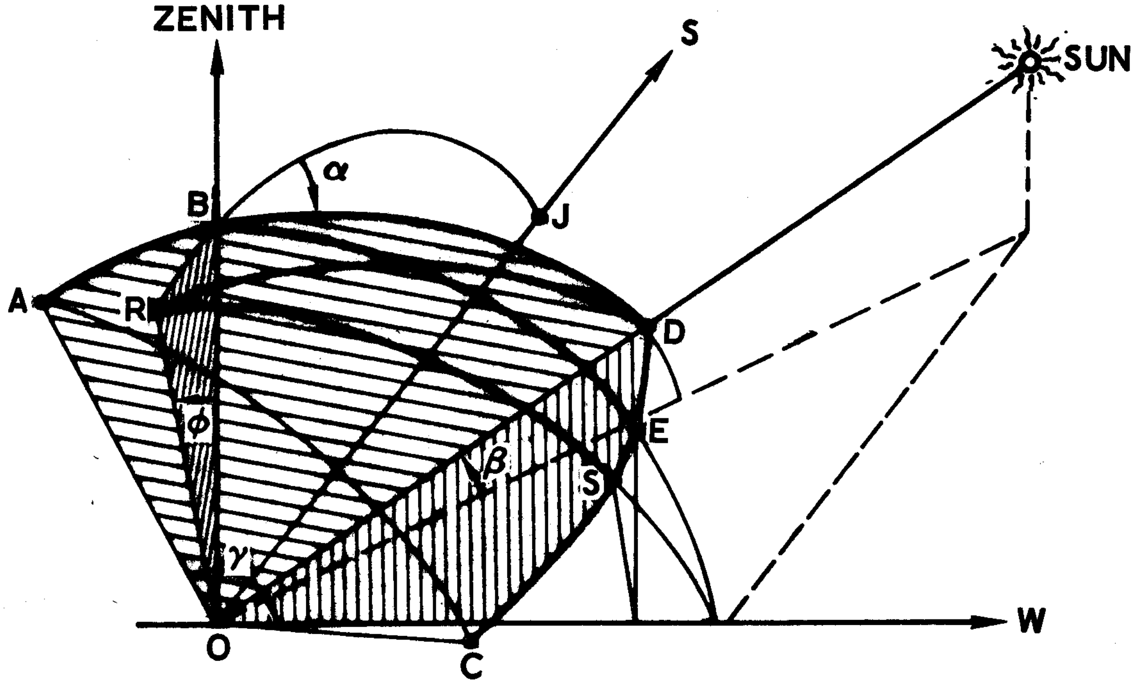

Figure A. 1. Quantities pertinent to the algorithm for the determination of the limits of integration over θ

Note: The plane denoted by RSO is the plane of the collecting aperture.

The plane denoted by ACO is perpendicular to the earth-sun line $\overline{OD}$.

$$\cos \overline{DS} = \cos \overline{RS} \cos \overline{RD} + \sin \overline{RS} \sin \overline{RD} \cos \overline{DRS} \qquad \text{(A-9)}$$

$$\overline{DS} = \tan^{-1} \left[\frac{\sin \overline{DS}}{\cos \overline{DS}} \right] \qquad \text{(A-10)}$$

Due to the manner in which the azimuth (α) is measured, certain logic modifications to the above equations were needed in order to maintain proper sign.

The algorithm for the computation of the limits of integration imposed by the boundary of the horizon consists of the following equations. Figure A. 2 illustrates the geometry involved along with the pertinent quantities. The arc $\overline{SH}$ is the limit of integration imposed by the horizon.

$$\cos A = \sin \gamma \cos \beta \qquad \text{(A-11)}$$

$$\sin \overline{SH} = \frac{\sin \beta}{\sin A} \qquad \text{(A-12)}$$

For proper calculation of the incident diffuse insolation, the projection factor must be computed for each incremental area of the sky being considered. The projection factor is equal to the cosine of the angle of incidence (i. e. $\cos \overline{NS'}$). Figure A. 3 presents the geometrical picture. The algorithm consisting of five equations is as follows:

$$\cos \overline{DN} = \sin \overline{RD} \cos \overline{BRD} \qquad \text{(A-13)}$$

$$\cos \overline{BDN} = \frac{\sin \varphi - \cos \overline{DN} \sin \beta}{\sin \overline{DN} \cos \beta} \qquad \text{(A-14)}$$

$$\angle \overline{BDS'} = \gamma \qquad \text{(A-15)}$$

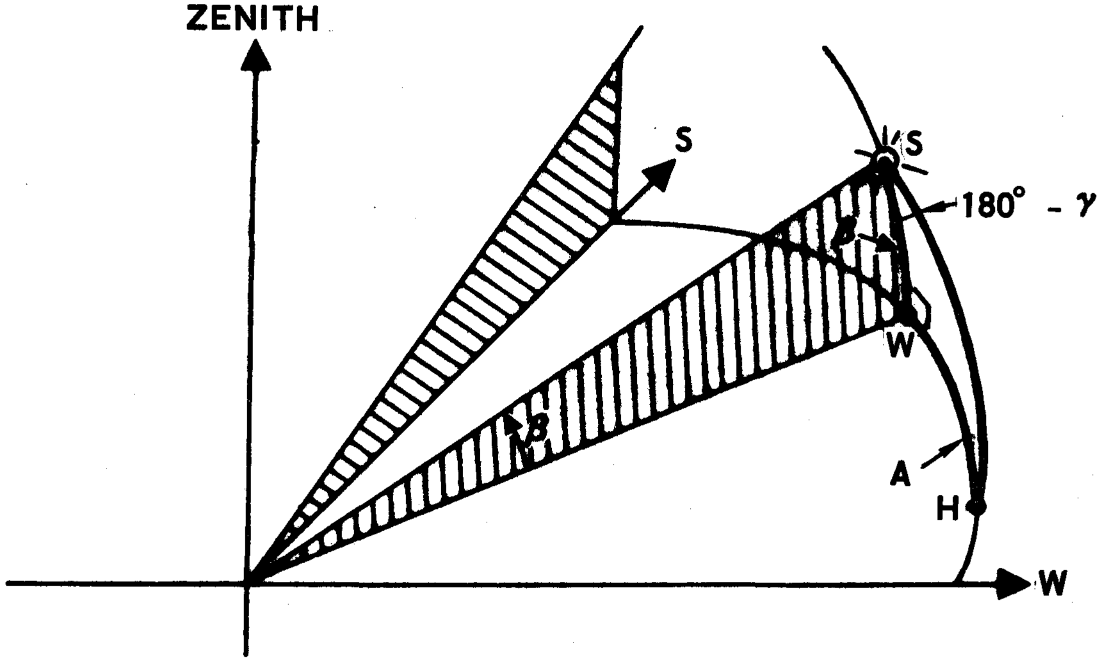

Figure A.2. Determination of limits of integration imposed by the boundary of the horizon.

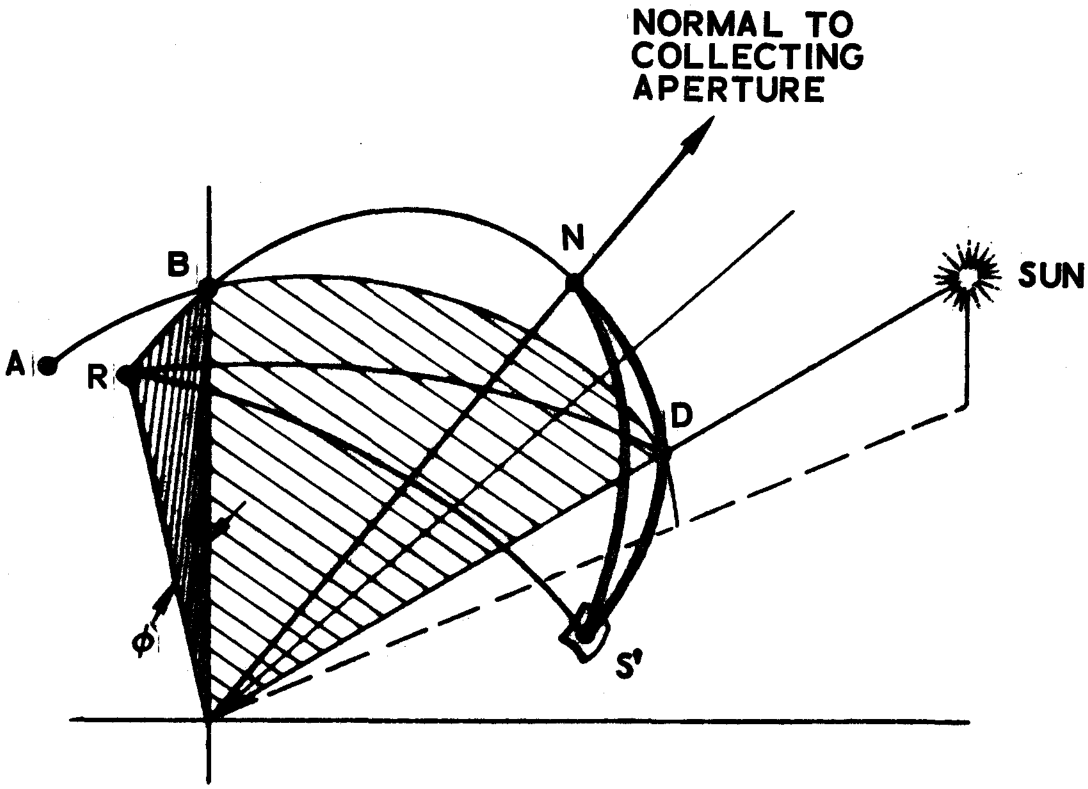

Figure A. 3. Projection factor for an arbitrary incremental area of the sky at S'.

$$\angle \overline{NDS'} = \angle \overline{BDN} + \angle \overline{BDS'} \tag{A-16}$$

$$\cos \overline{NS'} = \cos \overline{DN} \cos \overline{DS} + \sin \overline{DN} \sin \overline{DS} \cos \overline{NDS'} \tag{A-17}$$

The projection factor of each incremental area of sky is of prime importance for flat plate collectors due to the dependence of absorption of such collectors with angle of incidence. Collector coatings have slightly different absorption/incidence angle relationships, though the general form of the dependence is that due to the variation of reflectivity and therefore absorption with incidence angle off of a dielectric surface. The reflectivity is dependent upon the index of refraction (n) of the upper most material of the coating. The functional relationship is:

$$R = 1/2 \left[\left(\frac{n \cos \theta_i - \cos \theta_t}{n \cos \theta_i + \cos \theta_t} \right)^2 + \left(\frac{\cos \theta_i - n \cos \theta_t}{\cos \theta_i + n \cos \theta_t} \right)^2 \right] \tag{A-18}$$

where

$$\sin \theta_t = \frac{1}{n} \sin \theta_i$$

and

$$\theta_i = \text{angle of incidence}$$

It is assumed here that the upper most layer interfaces with air. The absorption is equal to:

$$\frac{(1-R)}{[1 - R\,(\text{normal incidence})]} \tag{A-19}$$

where

$$R(\text{normal incidence}) = \left(\frac{n-1}{n+1} \right)^2$$

This represents the energy that may be absorbed by the collector if the inherent absorptivity (α) of the coating were unity. It is a useful quantity as it is essentially independent of the absorption properties of the specified coating. It is more closely tied to the geometry of the problem. Realistic values of α range from .75 to .95 and would be multiplied by the above expression to obtain the actual total absorption by the flat plate collector.

The input coefficients required for the geometry model are not directly available, but must be sifted out of the insolation data base described in Volume II. For present purposes, the pieces of data used to determine the coefficients are the normal incident insolation and the percent of possible sunshine. The normal incident insolation data were obtained utilizing a pyrheliometer with a field of view of 6 degrees. Therefore, it was necessary to subtract the contribution outside of the sun's angular radius and within the 3 degree radius to obtain a more meaningful estimate of the incident direct insolation. Due to insufficient available data concerning the anisotropic component of the diffuse insolation, that coefficient was set to zero for the preliminary analysis.

The setting of the anisotropic term to zero is an acceptable assumption during clear weather when the direct component is dominant and in very cloudy weather in which the diffuse component is mostly isotropic. For intermediate type weather conditions, it may be a poor approximation, though the degree of inaccuracy is not certain at this time.

Referring to the expressing for the mathematical formulation of the incident insolation from an incremental area of the sky, one obtains:

$$S = A\cos\theta \int_{\substack{\text{sun's} \\ \text{disk}}} \cos\theta d\Omega + C \int_{\substack{\text{entire} \\ \text{sky}}} \cos\theta\, d\Omega \qquad \text{(A-20)}$$

$$= AJ\cos\theta + C\pi$$

where $J = \pi \sin^2 (.26^\circ) = 6.469 \times 10^{-5}$

and S = total insolation

likewise : $N = AJ + C \int_{\substack{\text{3 degree portion} \\ \text{of sky}}} \cos\theta\, d\Omega \qquad \text{(A-21)}$

$$= AJ + CK$$

where $K = \pi \sin^2 (3^\circ) = 8.6050 \times 10^{-2}$

N = normal incident insolation from the base insolation data.

Subtracting the two resultant equations, one obtains:

$$(S - N\cos\theta) = C(\pi - K\cos\theta)$$

$$C = \frac{S - N\cos\theta}{(1 - \frac{K}{\pi}\cos\theta)} \qquad \text{(A-22)}$$

$$AJ\cos\theta = S - \pi C = S - \pi\left(\frac{S - N\cos\theta}{1 - \frac{K\cos\theta}{\pi}}\right)$$

$$AJ = \left(\frac{N - \frac{K}{\pi} S}{1 - \frac{K}{\pi}\cos\theta}\right)$$

The solar insolation $S = (1.35\ \text{kw/m}^2)\left(\frac{P}{100}\right)\cos\theta$

where

P = percent of possible sunshine = insolation at surface/ insolation above atmosphere.

and

$$1.35 \ Kw/m^2 = \text{solar constant}$$

Therefore:

$$AJ = \left(\frac{N - 3.7004 \times 10^{-5} \ P \cos\theta}{1 - 2.739 \times 10^{3} \cos \theta} \right) \quad \text{(A-23)}$$

The isotropic diffuse insolation coefficient C is:

$$C = \frac{\cos\theta}{\pi} \left[\frac{.01351 \ P - N}{1 - 2.739 \times 10^{-3} \cos\theta} \right] \quad \text{(A-24)}$$

If the sun is below the horizon and therefore N = 0 (i.e. no direct insolation), A = 0. The coefficient C is equal to

$$\frac{\cos\theta}{\pi} \left[\frac{.01351P}{1 - 2.739 \times 10^{-3} \cos\theta} \right]$$

A parametric analysis of the effects of the anisotropic term on the total incident energy is waiting for more observational data pertaining to the distribution of the diffuse component.

APPENDIX B

ECONOMIC MODEL METHODOLOGY

The discounted cash flow economic analysis of power plants relates the cash flows from operation (CF) over the lifetime of the plant (N) with the total capital investment cost (TCI) at the year of commercial operation. The rate-of-discounting (k) is the weighed average cost-of-capital (after income taxes) of equity and debt financing as appropriate for the utility industry (Section 4.3.2). For public companies, the cost-of-capital is the effective interest rate on bond financing, and no taxes are imposed.

$$TCI_{co} = \sum_{i=1}^{N} (CF_i)/(1 + k)^i + RV_N/(1+k)^N \qquad \text{(B-1)}$$

The total capital investment at year of commercial operation is the sum of the various subsystem investment costs, including escalation and interest-during-construction costs (Section 4.3.3).

The residual value of the plant (RV) at the end of the useful plant life includes non-depreciable items such as land, thermal storage materials, or reflects cash expenses at this time such as nuclear plant decommissioning costs.

The yearly cash flows from operations are derived from the annual pro-forma income statements by adding non-cash expenses to net income after taxes. Net income after taxes (NI) is equal to revenues (REV_i) less expenses (EXP_i):

$$NI_i = (REV_i - EXP_i)(1 - TAXR) \qquad \text{(B-2)}$$

where TAXR is the average income tax rate applicable to the utility industry.

All revenue and expense accounts are normalized to plant capacity ($\$/KW_e/YR$).

Annual revenues (REV_i) for a plant are represented by the total busbar energy costs ($BBEC_i$) attributable to the plant prior to transmission and distribution costs. The annual total busbar energy costs are computed by the program such that the original investment is recovered as well as an adequate return-on-investment as determined by the cost-of-capital. The total busbar energy cost can vary from year to year of commercial operation due to rate increases, which is reflected in the program by an escalation of the busbar energy cost:

$$BBEC_i = BBEC_{co} (1 + e_B)^i \tag{B-3}$$

where e_B = escalation rate of busbar energy cost.

Annual expenses (EXP_i) are comprised of fuel (FUEL), other operating ($OPEX_i$), insurance (INS_i), property tax, depreciation ($DEPR_i$) and interest (INT_i) expenses. Fuel, insurance/property tax, and operating expenses are computed for each year of plant life by escalating the cost at year of commercial operation by the appropriate escalation rate. For example, fuel cost in a particular year (i) is related to year of commercial operation by two escalation rates:

$$FUEL_i = \begin{cases} FUEL_{co} (1+e_{F_1})^i & 0 \leq i < T \quad \text{(B-4a)} \\ FUEL_T (1+e_{F_2})^{(i-T)} & T < i \leq N \quad \text{(B-4b)} \end{cases}$$

Fuel cost at year of commercial operation ($FUEL_{co}$) ($\$/KW_e/YR$) can be computed from any base year by the appropriate escalation, heat rate, fuel cost, and plant capacity factor:

$$FUEL_{co} = FUEL_o (1+e_{F_o})^{(co-o)} \tag{B-5}$$

$$FUEL_o = HR \times FC_o \times (1-SOLAR) \times CF \times 8760 \times 10^{-6} \tag{B-6}$$

where HR = Heat Rate, Btu/Kwh

FC_o = Fuel Cost, \$/Million Btu

CF = Plant Capacity Factor

SOLAR = Percent of energy supplied by solar energy.

Similarly other operating ($OPEX_i$) expenses and insurance expenses (INS_i) are computed.

Interest cost (INT_i) is determined by the coupon interest rate (r)* on debt issues and the proportion of debt financing (L/V) of the total capital investment (TCI_{co}):

$$INT_i = r \times (L/V) \times TCI_{co} \tag{B-7}$$

Depreciation ($DEPR_i$) on depreciable plant equipment (DEBASE) can be computed by one of three methods, straight-line, sum-of-the-years-digits, or double-declining:

Straight-line: $DEPR_i = DEBASE/N$ (B-8)

Sum-of-years-digits: $DEPR_i = DEBASE \times 2(N-i+1)/N(N+1)$ (B-9)

Double-declining: If $i < N$,

: $DEPR_i = DEBASE \times (2/N)(1-2/N)^{i-1}$ (B-10a)

If $i = N$

: $DEPR_N = DEBASE \times (1-2/N)^{N-1}$ (B-10b)

The residual value of the capital investment (RV_N) net of capital gains taxes, is computed by escalating the value at year of commercial operation by the appropriate escalation rate for N years. For example for land:

$$RV_N = LAND_{co}(1+e_L)^N \tag{B-11}$$

Residual value is the end value adjusted for capital gain taxes. In the case of nuclear plants a decommissioning cost (after tax) is calculated can be included.

*Assuming no premium or discount.

The annual cash flow after taxes (CF_i) can be determined from the income statement by adding back the non-cash expenditures, i.e., depreciation ($DEPR_i$), to the net income after taxes (NI_i):

$$CF_i = NI_i + DEPR_i \tag{B-12a}$$

or by rearranging terms

$$CF_i = (BBEC_i - FUEL_i - OPEX_i - INSU_i - INT_i)(1 - TAXR) + DEPR_i\,(TAXR) \tag{B-12b}$$

By adjusting the total busbar energy revenues such that the net present value of these discounted cash flows equals to or is greater than the total investment at year of commercial operation of the plant, the plant investment is recovered with an adequate return-on-investment as required by investors (both equity and bond holders). The power plant economic model accomplishes the above objectives, and determines the total busbar energy cost in current and constant dollars for any year of commercial operation.

The total busbar energy cost obtained is tabulated in a format consistent with the electric power industry as shown in Figure B-1, in terms of variable costs (VC_i) and fixed charges (FC_i):

$$BBEC_i = VC_i + FC_i \tag{B-13}$$

This breakdown is accomplished in the program by rearranging the annual income statement. Variable cost is comprised of fuel costs plus other operating expenses (maintenance, repairs, etc.):

$$VC_i = FUEL_i + OPEX_i \tag{B-14}$$

BUSBAR ENERGY COST ≡ OPERATING COSTS + FIXED CHARGES

OPERATING COSTS	FIXED CHARGES
FUEL MAINTENANCE & REPAIRS WAGES & SUPERVISION WATER & SUPPLIES	COST OF MONEY DEPRECIATION INSURANCE TAXES

Figure B-1. Total Busbar Energy Cost

Fixed charges for a private company are the summation of cost of money (COM_i), which is the net income after taxes plus interest on debt, depreciation, insurance cost, and corporate income taxes:

$$FC_i = COM_i + DEPR_i + INSU_i + TAX_i \tag{B-15}$$

The program can be utilized to determine the relative economics of alternative power plants on a consistent basis, using this discounted cash flow investment analysis methodology. In addition, by varying various design/cost economic parameters, the sensitivity of these design and economic parameters can be assessed.

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