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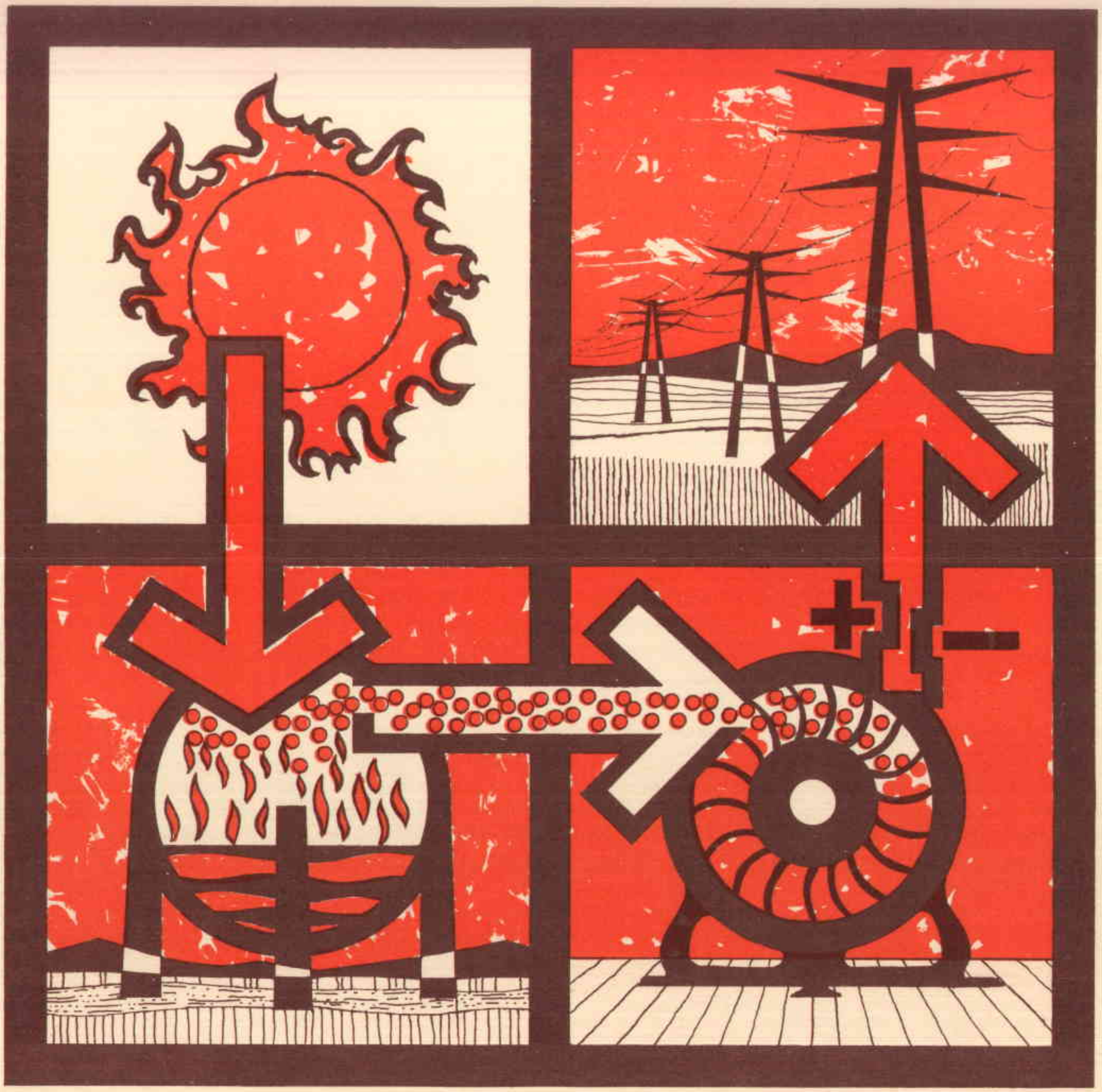
VOLUME IV

STMPO-010

SOLAR THERMAL CONVERSION MISSION ANALYSIS

Comparative Systems/Economics Analyses



THE AEROSPACE CORPORATION

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SOLAR THERMAL CONVERSION MISSION ANALYSIS
SOUTHWESTERN UNITED STATES

VOLUME IV
COMPARATIVE SYSTEMS/ECONOMICS ANALYSES

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FOREWORD

This report presents the results of the Comparative Systems/Economic Analyses of the Solar Thermal Conversion Mission Analysis as applied to the Southwestern United States performed by The Aerospace Corporation. The time period of the contract was from November 1, 1973 to August 15, 1974. This report is the fourth of five volumes; the remaining four volumes include a Summary Report; Southwestern United States Area Definition and Siting Analysis; Demand Analysis, and Insolation Climatology.

This study was conducted under a follow-on to NSF/RANN Contract C797 by the Energy Programs Group of the Energy and Resources Division. Mr. G. Kaplan was the NSF Program Manager for this contract; and Dr. A. B. Greenberg, General Manager of the Energy and Resources Division, was the Principal Investigator. Dr. M. B. Watson is the Associate Group Director of the Energy Programs Group. Mr. P. B. Bos, Associate Director, Solar Projects, provided the program management.

This report was prepared by the following authors: Mr. P. B. Bos, Mr. E. Blond, Dr. P. J. Peters, Mr. R. M. Selter and Mr. S. Sugihara.

The authors wish to acknowledge the diligent efforts of many people who have aided in bringing this study to completion. These include: Mr. W. Kammer, Mr. G. F. Kuncir, Mr. E. Lehnhof, Dr. S. L. Leonard and Dr. C. M. Randall.

The authors also wish to acknowledge the many organizations that have provided information and counseling in the formulation of this study, particularly the various utility companies and agencies in the Southwestern United States which have supplied the historic demand data, and the cooperation of other NSF system contractors in providing technical and cost data for the alternative systems considered in this study.

The authors express their sincere appreciation to Mr. M. S. Ensign for producing the tables and figures, to Mr. F. Eggers for technical editing, to Mr. H. Fockler for the cover design and to Ms. M. Bythway for the typing and preparing of this document.

ABSTRACT

This report describes the results of the comparative analyses conducted in evaluating the technical and economic performance of alternative solar thermal conversion concepts. This report describes primarily the application and extension of the mission analysis methodology initially developed under the preceding contract and described in previous reports. The material covered is an extension of and is complementary to that described in these previous reports. The mission analysis methodology was applied on a consistent basis to the evaluation of alternative solar thermal conversion concepts for providing electrical power under realistic operating environments.

This report is divided into five sections: a comparative technical evaluation, a margin analysis, a comparative economic evaluation, preferred system selection and definition, and environmental impact and market capture potential.

The comparative technical evaluation examines alternative solar thermal conversion systems and their relative ability to handle the dynamic interaction between varying insolation and electrical demand. The solar power plants are evaluated in a realistic operating environment by simulating the solar power plant performance as part of an integrated total utility system. Alternative operational modes to provide base, intermediate, and peaking power were examined.

A margin analysis was performed to ensure that the solar power plants integrated into the utility grid provide equal system reliability as a conventional system. As a result of increased unscheduled outages of solar plants, conventional backup generating capacity may be required to supplement the solar plants to meet the same reliability criterion established for the conventional power plant utility system. This backup generating

capacity was taken into account when making a comparative economic evaluation.

Having parametrically determined the technical performance of the solar power plants for different modes of operation, a comparative economic evaluation of these alternative solar thermal conversion power plants and conventional power plants was made to identify the preferred concepts and associated market capture potential.

The economics analysis methodology developed under the previous contract was used to perform the comparative economic evaluation. The details of the economic methodology have been published in an interim report "Power Plant Economic Model". (Reference 2) The analysis incorporates the technical performance determined from the systems analysis and conventional backup generation capacity determined by the margin analysis.

The technical and economic results in this report reflect the latest available data obtained from the various systems contractors, sponsored under the NSF Solar Thermal Conversion Program, and, consequently, reflect reasonable estimates of Solar Thermal Conversion systems at this time. These data permit preliminary selection and definition of the preferred system concepts. As technical and economic characteristics of these systems evolve as a result of more detailed systems analyses, these mission analyses described in this report will be updated to incorporate the latest available technical and economic information.

Based upon the comparative technical and economic assessment of the alternative Solar Thermal Conversion concepts and conventional power plants, the central receiver concept, operating in an intermediate or load following mode, appears competitive and has been identified as the preferred concept. Alternatively, if a low-cost parabolic cylindrical trough collector can be found, this concept could be developed as a back-up system.

A preliminary market capture potential of 40,000 MWe by the year 2000 was estimated, assuming a 100 MWe operational plant by 1985. No significant siting problems were found to prevent achieving this market potential.

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TABLES

1. OBJECTIVES

Under the previous contract (Reference 1) a methodology was developed for evaluating alternative solar thermal conversion missions and systems in realistic operational environments. The purpose of this methodology was to make an assessment of the potential role or mission of solar thermal conversion systems, and to identify those missions which have the greatest potential by considering technical, operational, economic, institutional, and environmental characteristics. During the present study this methodology was extended by incorporating more detailed subsystem design characteristics and improved computer simulations. This follow-on study was to address the Southwestern United States for potential application of Solar Thermal Conversion Systems during the time period 1980 to 2000.

Although the methodology has been applied to the Southwestern United States, the approach and individual analytical tools are applicable to other geographic regions. The technical and economic results reflect the latest available data obtained from the various systems contractors sponsored under the NSF/RANN program, and consequently, reflect reasonable estimates of Solar Thermal Conversion Systems at this time. These data permit preliminary selection and definition of the preferred system concepts. As technical and economic characteristics of these systems evolve as a result of further systems analyses, these analyses will be updated to incorporate the latest available information.

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 time varying load. Much of the effort is directed at selecting the proper subsystems such as collectors, storage, and conversion units. When the insolation energy is insufficient to meet the

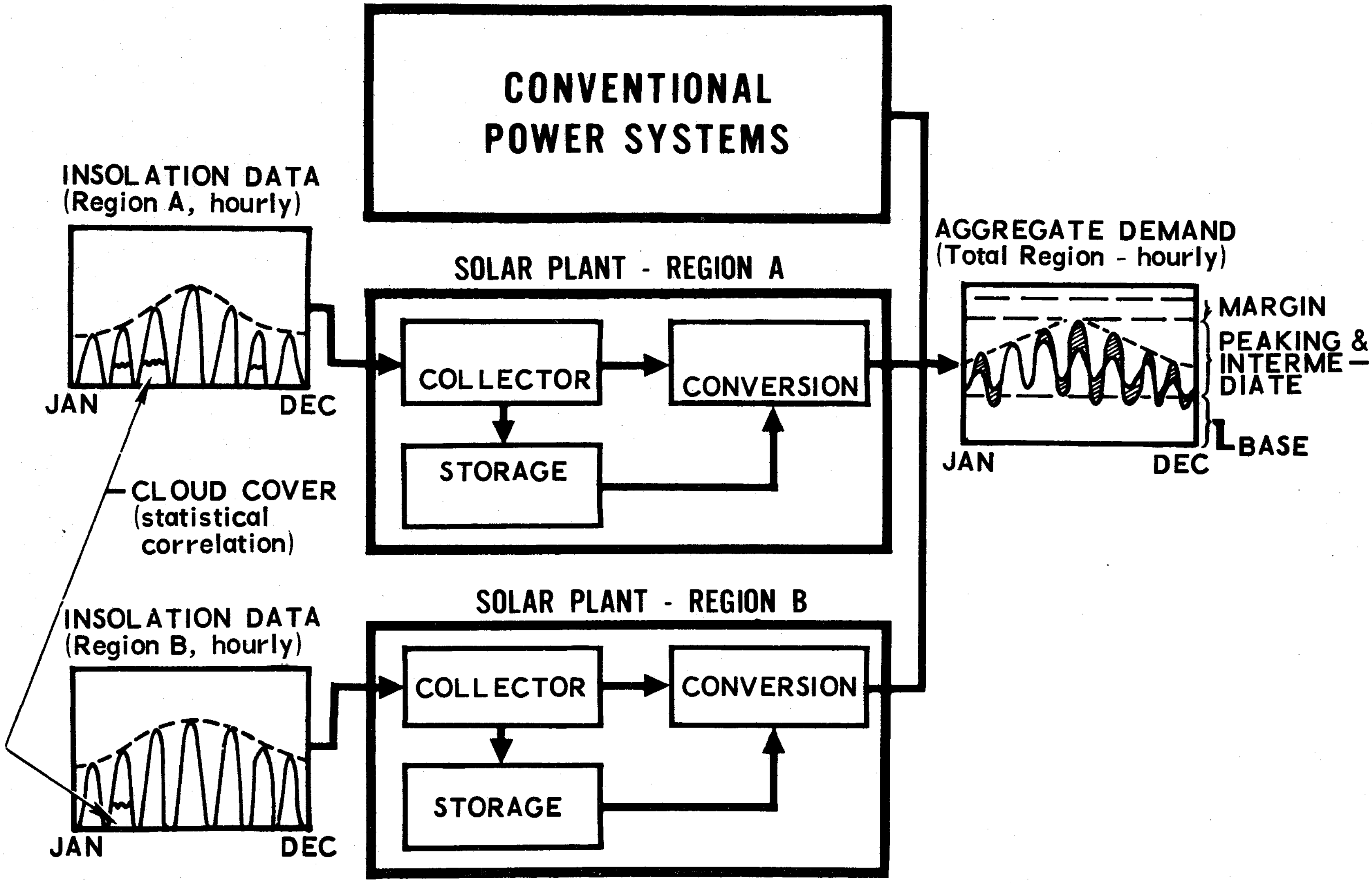


Figure 1-1. Mission Methodology, Integrated Solar and Conventional Power Grid

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 district. The mission analysis concerns itself with the interactions 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 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 too 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 at the 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, then the insolation reductions would be less important. The tradeoff between thermal storage and collector size, and the impact on utility 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 each climatic region identified in the Southwestern United States. The correlation between insolation and demand are important for utility margin analysis and will be addressed subsequently in this report. 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. The application of the methodology provides a basis for the selection of preferred missions and systems, and technical and economic requirements can be established for system, subsystem, and component design. Subsequently, a preliminary market capture potential of these preferred solar plants has been determined.

2. COMPARATIVE TECHNICAL EVALUATION

2.1 INTRODUCTION

This section describes the methodology and the results obtained from the comparative technical evaluation of alternative solar thermal conversion concepts. The primary objectives of the comparative technical evaluation are to examine the interaction of alternative solar thermal conversion systems with varying insolation and electrical demand. The solar power plants are evaluated in a realistic operating environment by simulating the solar plant performance as part of an integrated total utility system. These analyses utilize the hourly demand projections and regional insolation data described in detail in the Volumes II and III of this report, respectively.

A methodology was developed under the previous contract to parametrically assess the performance characteristics of alternative solar thermal conversion missions and systems in realistic operating environments on a consistent basis. This model has been extended, under the present contract, to incorporate solar plant subsystem design characteristics obtained from point design studies conducted by other NSF system contractors.

In order to determine the preferred mission applications of the solar thermal conversion systems, alternative operational modes to provide base, intermediate, and peaking power were examined. Alternative solar thermal conversion systems were parametrically evaluated on a consistent basis in order to establish comparative performance results.

Four different solar power plant concepts were considered for evaluation:

- Central Receiver System
- Parabolic Cylindrical Trough (including north-south, east-west and polar orientations)
- Paraboloidal Dish
- Planar Collector

The low-concentrating planar collector concept evaluation has not been completed, and results are not presented in this report.

For the alternative solar power plant concepts, collector area and storage capacity were varied parametrically to determine the energy displacement and outage rates. 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 system concepts and mode of operation.

2.2 ALTERNATIVE SOLAR THERMAL CONVERSION SYSTEMS

A pictorial representation of the four basic solar thermal conversion concepts considered in the comparative systems analysis is presented in Figure 2-1. The concepts portrayed include the central receiver, paraboloidal dish, parabolic cylinder, and planar collector. Though these concepts incorporate major design differences, the system methodology presented in this section can accommodate the various design concepts for comparison on a consistent basis.

The central receiver concept uses optical transmission for redirecting the incident solar energy from a field of heliostats (i. e. mirrors) onto a receiver located on top of a tower, thereby achieving high solar concentration and associated temperatures. Each heliostat can be rotated about two axes to enable directing the insolation to the receiver under varying relative solar positions. The energy absorbed at the receiver is transferred to a thermal transport fluid (e. g., water, steam, hitec, etc.), and transported directly to a turbine/generator located in close proximity to the tower for the conversion to electrical energy or to storage for later delivery to the turbine/generator.

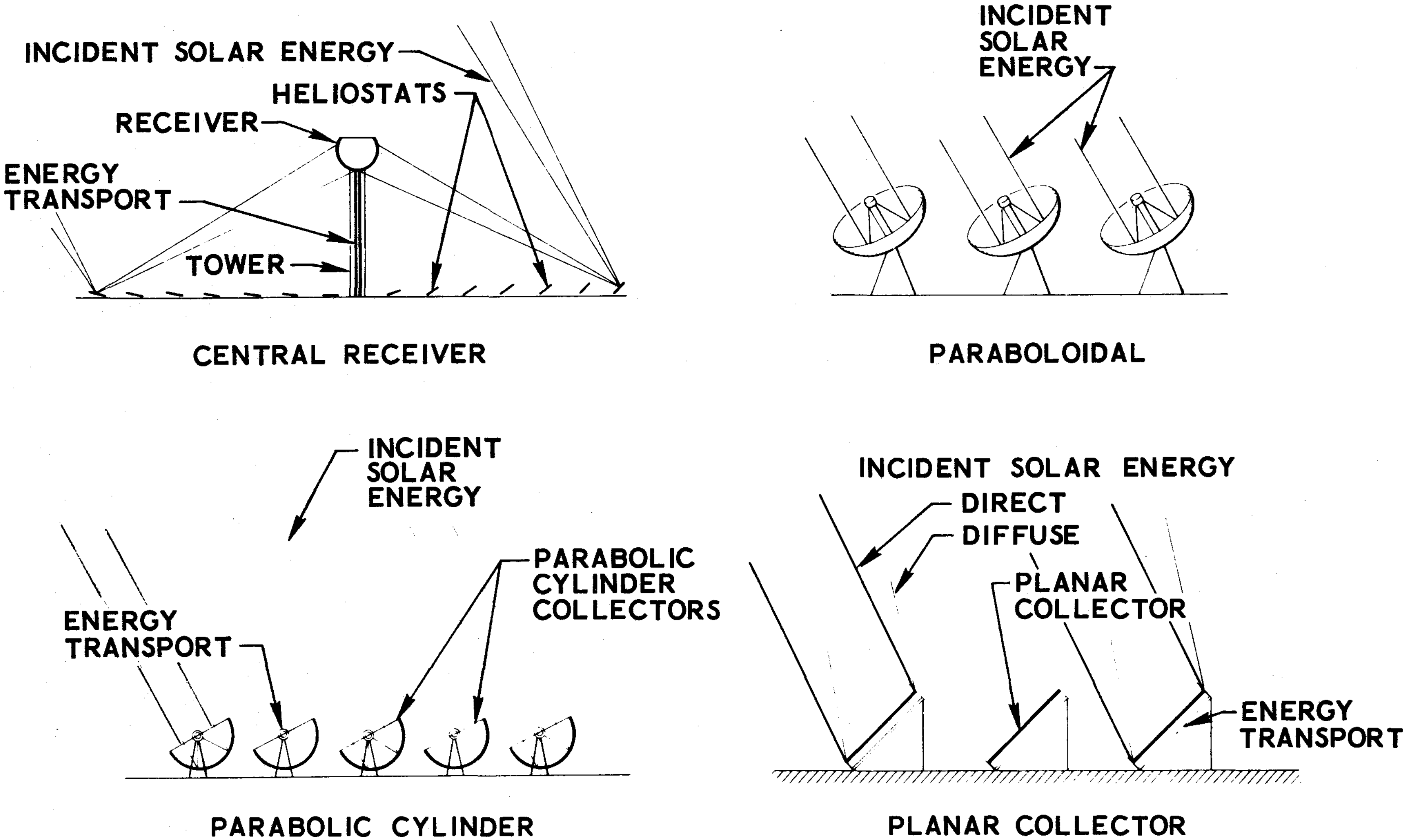


Figure 2-1. Alternative Solar Thermal Conversion System Concepts

The other three concepts are distributed systems. These concepts utilize distributed solar collectors, which locally convert the incident insolation to thermal energy, and require long pipe runs to collect and transport heated fluid to the turbine/generator and/or central storage system. Long pipe runs, even with good insulation, can incur significant thermal losses and are very costly.

The paraboloidal concept consists of large individual paraboloidal dish reflectors that direct the incident insolation to a single focus (receiver) located at the focal point of each reflector. Each paraboloidal dish tracks in two directions, and can theoretically achieve high concentration ratios and associated temperatures.

The parabolic cylinder concept consists of cylindrical troughs with a parabolic cross section which direct the incident insolation to an absorbing pipe located at the focus of the parabola. The central pipe, or receiver, contains the thermal transfer fluid. The receiver is surrounded by an evacuated glass envelope to prevent excessive thermal losses and to protect against atmospheric corrosion. Each collector tracks only in one direction about its longitudinal axis. Because of the lower concentration ratios achievable with this concept, the collector pipe may utilize a high absorbivity/low emissivity coating in order to achieve high operating temperatures. The parabolic cylinder system, like the paraboloidal system, is distributed over a large ground area requiring long pipe runs to transport the thermal transfer fluid to the turbine/generator or storage. Three separate types of parabolic cylinders are considered in the analyses, differing primarily in the orientation of the rotation axis. The three orientations are:

- North-South
- East-West
- Polar

The polar orientation has the rotation axis tilted with respect to the horizon at an angle equal to the latitude of the site. This reflects an optimal setting for collecting solar insolation on an annual integrated basis by minimizing geometric losses. As the parabolic cylinder concepts employ one-directional tracking, tracking efficiencies vary for each of the three orientations.

Planar collectors either have no concentration (flat plate) or low concentration (Winston type). These concepts have the ability to utilize total (direct and diffuse) radiation, as compared to those concepts employing higher concentration which can only utilize direct (or focusable) insolation. The planar collector concept typically employs fixed collectors or requires seasonal orientation adjustments only depending upon the amount of concentration. The tracking requirements and typical operating temperatures achievable for the local absorption or distributed collectors and the central receiver are shown in Table 2-1.

2.3 SYSTEM MODELING

The mission/systems analysis examines the dynamic interaction of varying insolation and electric power demands on the performance of alternative solar power plants with differing system characteristics. The solar power plants were evaluated in a realistic operating environment by simulating their performance as part of an integrated total utility system. Alternative operational modes were examined providing base, intermediate and peaking power in order to determine the preferred mission applications of the solar power plants.

Each of the solar power concepts was analyzed with varying collector areas and storage capacity for different operational modes to parametrically determine the energy displacement and solar plant outage rates. The solar plant outage rate is necessary to determine the capacity displacement of

Table 2-1. Alternative Solar Thermal Conversion Concept Comparison

LOCAL ABSORPTION COLLECTORS	TRACKING REQUIREMENTS	OPERATING TEMPERATURE (°F)
FLAT PLATE	NONE	100 - 270
AUGMENTED FLAT PLATE	NONE OR SINGLE-AXIS	200 - 500
PARABOLIC TROUGHS	SINGLE-AXIS	400 - 1200
PARABOLOIDS	TWO-AXIS	500 - 2000
CENTRAL RECEIVER COLLECTORS		
FLAT MIRRORS	TWO-AXIS	500 - 2000
FOCUSED MIRRORS	TWO-AXIS	500 - 2000

these solar plants which, when combined with energy displacement, permits the economic assessment of the alternative solar thermal conversion concepts.

The comparative systems analysis uses the dynamic system/simulation model developed under the previous contract to parametrically assess the performance characteristics of the alternative solar thermal conversion missions and systems. This model has been extended under the present contract to incorporate solar plant subsystem design characteristics obtained from point design studies conducted by other NSF system contractors.

2.4 SYSTEM SIMULATION MODEL

A block diagram of the modular system simulation model is shown in Figure 2-2. This model consists of modular subsystem routines to facilitate substitution of more complex subroutines as design characteristics become better defined. The insolation subroutines are the hourly total and normal-incidence insolation data representative of the various climatological subregions of the Southwestern United States.

The tracking, collector/receiver, transport, storage, turbine/generator and transmission subroutines compute the various system energy losses between the incident insolation and the delivery of electrical energy. Subsystem design characteristics and those from point design studies conducted by other NSF study contractors were used in modeling subsystem losses.

Since total insolation is typically 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. The

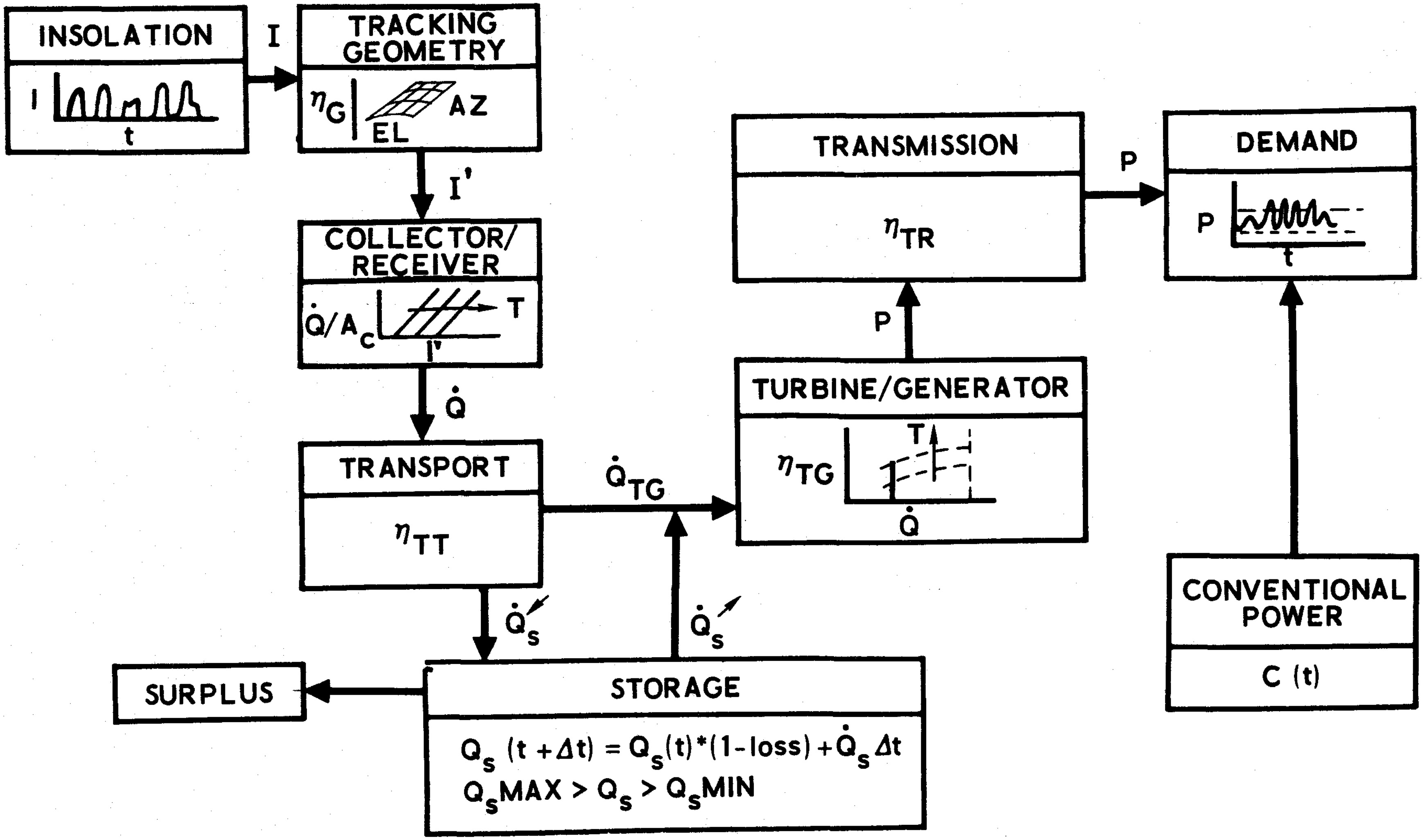


Figure 2-2. Simulation Block Diagram

tracking model will therefore compute the insolation energy which can potentially be collected.

The collector subsystem defines the total collector area and the losses associated with its design configuration (e.g., reflectivity, aiming losses, shading). The receiver subsystem, which receives the collected solar energy, is represented by an absorption efficiency and convective and radiative losses which are temperature dependent. A threshold insolation level is incorporated below which the receiver does not operate.

The energy transport subsystem represents the primary energy fluid pumping losses and the line thermal energy losses. The thermal energy can be utilized directly by the turbine/generator, or stored for future utilization, depending on the power demand and generator rating.

The storage subroutine incorporates a maximum and minimum storage capability as well as an overflow provision. Representative thermal energy losses are incorporated within this model to account for energy input/output losses as well as heat loss rates during storage.

The turbine/generator subroutine accounts for the conversion of the thermal energy into electrical energy with a conversion efficiency which is a function of the operating temperature. 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, or peaking hourly load for any given year as forecasted by the demand methodology discussed in Volume II of this report. This model permits the simulation of solar power plants integrated into a power grid on an hour-by-hour basis. Typically the simulation is carried out for a full year. The systems analysis model is sufficiently flexible to permit comparative evaluation of alternative solar concepts while maintaining consistency and operational realism.

2.4.1 Insolation Data Input

An hourly insolation data base was formulated for twenty separate sites representative of the various climatic regions in the Southwestern United States for use in system simulation analyses, as described in detail in Volume III of this report. 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:

- o Identifying information, which includes such information as data, time, and solar position.
- o Insolation data, including extraterrestrial, normal incidence and total insolation, as well as the ratio of total to extraterrestrial insolation.
- o 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 bases. The use of these data by contractors in the performance calculations will greatly facilitate the consistent evaluation of alternative system concepts.

2.4.2 System Losses

The systems analysis model sequentially analyzes solar plant subsystem losses. The subroutines are designed to facilitate incorporation of detailed subsystem performance characteristics and are flexible to permit analysis of alternative solar power plant concepts. The system losses can be segregated into the following major subsystem programs:

- Tracking/Geometry
- Collector/Receiver
- Energy Transport System
- Thermal Storage
- Turbine/Generator
- Electric Power Transmission

Some of these major subsystem routines are further segregated to adequately represent the performance characteristics of these subsystems.

2.4.2.1 Tracking/Geometry Subroutine

To realistically determine the insolation input for a solar collector as a function of time and location, appropriate tracking/geometry models were developed to characterize the alternative collector concepts. This subroutine determines the relative orientation of the collector aperture as determined by the relative geometry of the particular concept.

The model incorporates the effects of shading and blocking of the collectors and the receiver, which are a function of the area utilization or relative proximity of the collectors. The model has been designed to incorporate data obtained from detailed collector simulation routines developed by the representative system design contractors. Rather than duplicating the efforts of these contractors and to minimize computer costs for hourly simulation over an entire year only the final results are typically incorporated either in formula, tabular, or graphic form. These data, however, must accurately reflect the detailed simulation for each hour throughout the year and, consequently, are input as a function of solar elevation and azimuth angles relative to the collector. The relative solar position and insolation are input using the hourly insolation data base information.

(1) Central Receiver Concept Tracking Efficiency

To illustrate the incorporation of detail design data for hourly system simulation over an entire year, typical tracking efficiency input data for the central receiver concept is shown in Figure 2-3. The data shown were obtained from detailed analysis of the winter-perturbed central receiver design by the University of Houston for various combinations of solar azimuth and elevation. The tracking efficiency includes collector losses due to the relative orientation of the heliostats and the effects of shading and blocking by adjacent heliostats. Shading is the energy loss due to one mirror being shadowed by another from direct sunlight. Blocking is the prevention by adjacent mirrors of reflected sunlight reaching the receiver.

Rather than duplicating these complex analyses, these data were input parametrically into the simulation program for hourly simulation of this concept. Derivatives at the respective nodes of the graphs were graphically determined for inclusion into a two-dimensional Aitken-Hermite interpolation routine in the system simulation. For each hour of the day throughout an entire year the direct insolation and solar position, as developed in the data base, are input to determine the total redirected insolation to the central receiver. Consequently, the tracking performance accurately reflects the actual performance results as determined by the system design contractor without incurring the large costs of duplicating and simulating on an hourly basis the contractor computer program. Superimposed on the data in Figure 2-3 are constant time lines as

Central Receiver Concept Tracking Efficiency

UNIV. OF HOUSTON/MDAC (winter orientation)

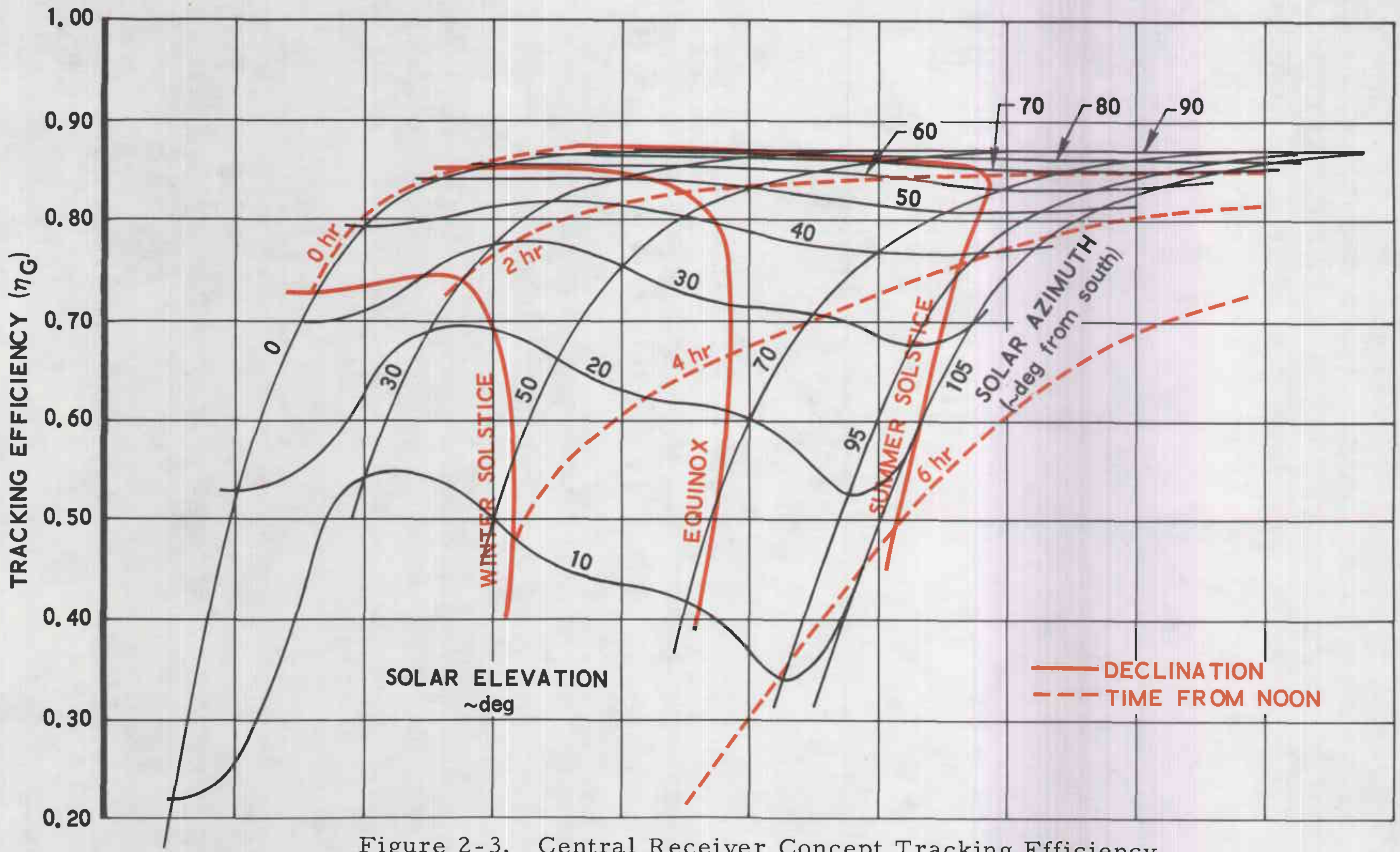


Figure 2-3. Central Receiver Concept Tracking Efficiency

measured from noon and lines of constant declination for the extreme solar days as measured by the equinox and solistices.

Using this program, three separate central receiver configurations were investigated: 1) winter optimum, 2) winter perturbed and 3) summer perturbed. Each of the models was optimized for a particular season of the year, with the resulting difference being the density distribution of the heliostats, geometry of the field, and position of the tower. The latter two models also include a combined error term for tracking and mirror imperfections (3 milliradians).

(2) Parabolic Cylinder Concept

The tracking/geometry losses for the parabolic cylinder system include tracking, aiming, shading, primary and secondary reflectivity losses. The tracking efficiency was modeled separately by consideration of the geometrical relationships between the collector aperture and the hourly solar orientation. The basic equations governing this relationship are presented in Appendix A. Since the parabolic cylinder tracks the sun in one direction only, the integrated tracking efficiency is less than unity and varies for each of the three collector orientations considered.

The effects of shading from neighboring collectors were investigated by the Honeywell Corporation for each of the three orientations of the parabolic cylinder. The shading results were assembled in tabular form as a function of hour angle and declination. These tables were incorporated as a subroutine in the systems simulation model using a two-dimensional linear interpolation routine developed specially for the calculation of the shading efficiency. A program option exists to either use these tables or a single efficiency value for the hourly simulations. It is interesting to note that the shading losses of the polar oriented collector are greater than that for the other two orientations, thereby negating some of the higher tracking efficiency. This relatively poor shading performance is due to the increased shading in the winter season during the peak solar elevation hours. The primary and secondary reflectivity losses are represented by efficiencies characterizing the respective surfaces.

An algorithm for the aiming losses was derived from the results of the Honeywell Corporation point design studies of the parabolic cylinder collector. These results were determined from a detailed ray-trace computer program. In order to properly simulate these results on an hourly basis, it was necessary to express the aiming efficiency as a function of the solar incidence angle. The algorithm determined for the aiming efficiency necessary to match these detailed collector performance results is as follows:

$$\eta_{AIM} = 1.244\left(1 - \frac{0.23}{\cos\alpha}\right) \tag{2-1}$$

$\cos\alpha$ = cosine of the angle of incidence (angle between the normal of collector and the collector-sun line)

(3) Paraboloidal Dish Concept

In the simulation of the paraboloidal dish the tracking efficiency is unity, and consequently only aiming, shading and primary reflectivity losses were considered.

The shading losses were computed as described for the parabolic cylinder system, again using the Honeywell Corporation tabular shading information. The primary reflectivity losses were represented by the efficiency of the primary reflective surface and the secondary reflectivity losses were neglected. The aiming losses were represented by an aiming efficiency calculated to match the Honeywell Corporation paraboloidal dish performance results.

2.4.2.2 Collector/Receiver Subroutine

After the appropriate geometrical tracking transformations have been made, the insolation input from the reflector to the receiver (after taking into account the reflectivity losses) is subject to absorptivity, convective and radiative losses. These losses relate the insolation input to the receiver and the working fluid thermal output. Parameters affecting receiver performance are the receiver area, absorbtivity, surface temperature, wind velocity, and re-radiation characteristics, among others.

The absorbtivity losses can be represented by an efficiency term which is equivalent to the receiver surface absorbtivity (α).

The combined convective re-radiative power losses can be expressed by the receiver efficiency (η_R):

$$\eta_R = \frac{\text{Power Out}}{\text{Power In}} = \frac{\dot{Q}_{in} - \Delta\dot{Q}_{RL}}{\dot{Q}_{in}} \qquad (2\text{-}2)$$

where: $\Delta\dot{Q}_{RL}$ = combined convective/re-radiative energy losses

The combined convective/radiative power losses can be simulated in this subroutine by any one of the three program options, depending upon the level of detailed subsystem information available.

(1) A constant thermal efficiency, η_R (2-3)

(2) Unit area thermal power loss, $\dot{q}_{RL}$

where: $\Delta\dot{Q}_{RL} = \dot{q}_{RL} \times A_c$ (2-4)

and: $\dot{q}_{RL}$ = Receiver thermal power loss per unit collector area

A_c = Total collector area

(3) Calculated receiver thermal power loss, $\Delta\dot{Q}_{RL}$

where: $$\Delta\dot{Q}_{RL} = [h_c \times R\,(T_c - T_a) + \sigma\,\epsilon\,(T_r^4 - T_a^4)] \times A_r \qquad (2\text{-}5)$$

and:

R = Convective surface to receiver surface (e.g., glass envelope) area ratio

h_c = Convective coefficient

σ = Steffan-Boltzman constant

ϵ = Receiver surface emissivity

T_c = Receiver or glass envelope surface temperature

T_r = Receiver surface temperature

T_a = Ambient air temperature

A_r = Receiver surface area

2.4.2.3 Energy Transport Subroutine

The heat flux output from the receiver 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.

Two separate losses are considered in this subsystem: pumping losses and thermal energy losses. The pumping losses can be expressed by an overall loss of efficiency factor (η_P):

$$\eta_P = \frac{\text{Power Out}}{\text{Power In}} = \frac{\dot{Q}_{in} - \Delta\dot{Q}_{PL}}{\dot{Q}_{in}} \qquad (2\text{-}6)$$

where: $\Delta\dot{Q}_{PL}$ = Total pumping power losses

This pumping efficiency factor can be simulated in this subroutine by any one of three program options, depending upon the level of detailed subsystem information available:

(1) A constant pumping efficiency, η_P (2-7)

(2) Unit pump power loss, $\dot{q}_{PL}$

where: $\Delta\dot{Q}_{PL} = \dot{q}_{PL} \times A_c$ (2-8)

and: $\dot{q}_{PL}$ = Pumping power loss per unit collector area

A_c = Total Collector area

(3) Calculated pumping power loss, $\Delta\dot{Q}_{PL}$

where: $\Delta\dot{Q}_{PL} = \left[P_c/(A_c)^2\right] \dot{Q}^3$ (2-9)

and: P_c = Pumping constant (derived from contractor data)

$\dot{Q}$ = Total thermal energy flow rate

A_c = Total collector area

Note: Two considerations are involved with the latter pumpint loss relationship. First, for a fixed collector area and pipe size:

$\Delta\dot{Q}_{PL} \sim \dot{Q}\,(\Delta P)$ (2-10)

and: $\Delta P \sim (\dot{Q})^2$ (2-11)

where: ΔP = System pressure drop

Therefore: $\Delta\dot{Q}_{PL} \sim (\dot{Q})^3$ (2-12)

Second, an increase in collector area (which results in an increase in flow rate at fixed fluid temperatures) is offset by an increase in pipe area sufficient to maintain a constant system pressure drop.

Since: $$\dot{Q} \sim A_c \tag{2-13}$$

$$\Delta P \sim \frac{(\dot{Q})^2}{(A_p)^2} \sim \frac{(A_c)^2}{(A_p)^2} \tag{2-14}$$

where: A_p = Pipe cross-sectional area

To maintain ΔP constant with varying A_c:

$$A_p \sim A_c \tag{2-15}$$

Therefore: $$\Delta\dot{Q}_{PL} \sim \dot{Q}\Delta P \text{ or } \frac{(A_c)^3}{(A_p)^2} \text{ or } \frac{(\dot{Q})^3}{(A_c)^2} \tag{2-16}$$

This relationship accounts for an increase in pipe diameter corresponding to an increase in collector area.

The energy transport system thermal energy losses can also be expressed by an overall efficiency factor (η_L):

$$\eta_L = \frac{\text{Power Out}}{\text{Power In}} = \frac{\dot{Q}_{in} - \Delta\dot{Q}_{LL}}{\dot{Q}_{in}} \tag{2-17}$$

where: $\Delta\dot{Q}_{LL}$ = Total energy transport thermal power losses

Again, three options are available for simulating these transport thermal power losses:

(1) A constant energy transport system thermal power loss efficiency, η_L (2-18)

(2) Unit energy transport system thermal power loss, $\underline{q}_{LL}$

where: $\Delta\dot{Q}_{LL} = q_{LL} \times A_c$ (2-19)

and: $\dot{q}_{LL}$ = Energy transport system thermal power loss per unit collector area

A_c = Total collector area

(3) Calculated thermal transport system thermal power loss $\Delta\dot{Q}_{LL}$

where: $$\Delta\dot{Q}_{LL} = \frac{2\pi kL(T_s - T_a)}{\ln(r_2/r_1)} \tag{2-20}$$

and: L = Length of piping

k = Insulation conductivity

r_2 = Outside insulation radius

r_1 = Inside insulation radius

T_s = Fluid temperature

T_a = Ambient temperature

Note: Insulation is assumed to be the predominate factor in determining this thermal power loss.

After the heat flow has been reduced by the thermal transport losses, 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:

- o If an electric demand is present which is greater than the minimum operating level of the turbine/generator (G_{min}), thermal energy available from the collector is sent to the turbine/generator.
- o 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.

2.4.2.4 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 subsystem can accept thermal energy from the collector field at any desired input rate.

- The storage subsystem has a maximum thermal capacity specified in terms of the number of hours of the turbine/generator operation at its rated capacity.

- Input and output thermal losses to and from the thermal storage subsystem are accounted for by efficiencies proportional to the energy input/output rates.

- In addition, the storage subsystem looses thermal energy to its surroundings at a rate proportional to the amount of energy in storage.

- The storage subsystem can supply thermal energy to the turbine generator at a rate sufficient for operation at its maximum rated capacity.

- If a minimum value of thermal energy in storage is reached, the storage unit will not supply further energy to the turbine/generator.

- The storage subsystem 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 energy input and output losses to and from the thermal storage subsystems are represented by the respective efficiencies:

$$\frac{d}{dt}\,(HIS)_t = \eta_{in}\,\frac{d}{dt}\,(HIS)_{in} \tag{2-21}$$

$$G_{in} = \eta_{out}\,\frac{d}{dt}\,(HIS)_t \tag{2-22}$$

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

Since: $$HIS_t = HIS_{t-1}\,(1-\alpha) - G_{in}/\eta_{out} \tag{2-23}$$

Therefore: $$HIS_n = HIS_o\,(1-\alpha)^n - \frac{G_{in}}{\eta_{out}}\left[\frac{1 - 1(1-\alpha)^n}{\alpha}\right] \tag{2-24}$$

if: $$HIS_n = \beta\, HIS_o \tag{2-25}$$

Then: $$HIS_o = \frac{G_{in}}{\eta_{out}}\left[\frac{1 - (1-\alpha)^n}{\left|\alpha\,(1-\alpha)^n - \beta\right|}\right] \tag{2-26}$$

and: $$HIS_{in} = HIS_o/\eta_{in} \tag{2-27}$$

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_{in} = Maximum capacity of the thermal energy storage in terms of thermal energy input from the collectors (Kwh_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_t/hr)

β = Minimum level of thermal energy in storage, expressed as a percent of the maximum storage capacity

η_{in} = Thermal energy input efficiency

η_{out} = Thermal energy output efficiency

2.4.2.5 Turbine/Generator Subroutine

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

$$G_{out} = \eta_{TG} G_{in} \qquad (2\text{-}28)$$

2.4.2.6 Electric Power Transmission Subroutine

The electrical transmission losses are simulated by an efficiency term (η_{TR}). Consideration of transmission losses is dependent on whether the comparative economic evaluation is based on busbar energy costs or wholesale/retail costs.

2.4.3 Demand Requirements

The electrical power demand is the hourly forecast as determined by the demand analysis as described in Volume III. 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.

2.4.4 Program Inputs and Outputs

The basic inputs to the program are:

1/ Insolation
- o Site Selection
- o Hourly insolation data and ambient temperature

2/ Tracking/Geometry

- o Collector concept and orientation
- o Aiming efficiency (programmed for some collector concepts)

3/ Collector/Receiver

- o Collector area
- o Primary and secondary reflector efficiencies
- o Absorption efficiency
- o Receiver thermal efficiency
  - or: Receiver thermal loss per unit collector area
  - or: Receiver surface characteristics and temperature

4/ Energy Transport

- o Pumping efficiency
  - or: Pumping power loss per unit collector area
  - or: Pumping constant
- o Line thermal power loss efficiency
  - or: Line thermal power loss per unit collector area
  - or: Line and insolation characteristics and fluid temperature

5/ Thermal Storage

- o Maximum and minimum thermal storage capacity
- o Storage input and output efficiencies
- o Storage thermal loss rate

6/ Turbine/generator

- o Turbine/generator efficiency
- o Turbine/generator rated capacity
- o Turbine/generator minimum operating level

7/ Electrical power transmission

- o Electric power transmission efficiency

2.5 COMPARATIVE TECHNICAL EVALUATION

The primary objectives of the comparative technical evaluation are to examine the interaction of alternative solar thermal conversion systems with varying insolation and electrical demand. The solar power plants are evaluated in a realistic operating environment by simulating the solar plant performance as part of an integrated total utility system.

Alternative solar thermal conversion systems were parametrically evaluated on a consistent basis in order to establish comparative performance results. Four different solar power plant concepts were considered for evaluation:

- Central Receiver System
- Parabolic Cylindrical Trough (including north-south, east-west and polar orientations)
- Paraboloidal Dish
- Planar collector

The low-concentrating planar collector concept evaluation has not been completed, and results are not presented in this report.

In order to determine the preferred mission applications of the solar thermal conversion systems, alternative operational modes to provide base, intermediate, and peaking power were examined. For the alternative solar power plant concepts, collector area and storage capacity were varied to parametrically determine the energy displacement and solar plant outage rates. The solar plant outage rate is determined through simulation calculations. This rate is input to a margin analysis which identifies the capacity displacement of the solar plants, which when combined with the energy displacement, permits the economic assessment of alternative system concepts and modes of operation.

The system combination with the lowest cost will be determined by means of economic and financial evaluation of the energy and capacity-displacement potential for each mode of operation of the solar plants.

The range of collector areas and thermal storage capacities is shown in Table 2-2 for the different operating modes.

Different modes of operation for solar power plants were examined by selecting the various operating ranges shown in Figure 2-4:

- o Base load between 0 and 100 MWe.
- o Intermediate load between 22,000 and 22,100 MWe.
- o Peaking load between 27,300 and 27,400 MWe.

The 0-100 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 the marginal cost of operating a solar plant is lower than for a corresponding conventional plant, it was assumed that the solar plant will operate at times when the electric 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 insolation and/or stored energy was adequate and the turbine/generator capacity was available. However, operation outside these bands contributed only to energy (fuel) displacement in the comparative economic evaluation.

2.5.1 Electrical Power Demand

The electric power demand used for system simulation is shown in Figure 2-4. For illustration, only the first weeks in April, August, and December are shown, although a full year is used in the simulations.

Table 2-2. Solar Thermal Conversion Systems Simulation

BASE LOAD SOLAR PLANT	
• DEMAND RANGE	0 - 100 MW_e
• COLLECTOR AREAS	1 - 4 KM^2
• THERMAL STORAGE	0 - 18 HR
INTERMEDIATE SOLAR PLANT	
• DEMAND RANGE	22,000 - 22,100 MW_e
• COLLECTOR AREAS	0.5 - 2.5 KM^2
• THERMAL STORAGE	0 - 9 HR
PEAKING SOLAR PLANT	
• DEMAND RANGE	27,300 - 27,400 MW_e
• COLLECTOR AREA	0.5 - 1.5 KM^2
• THERMAL STORAGE	0 - 6 HR

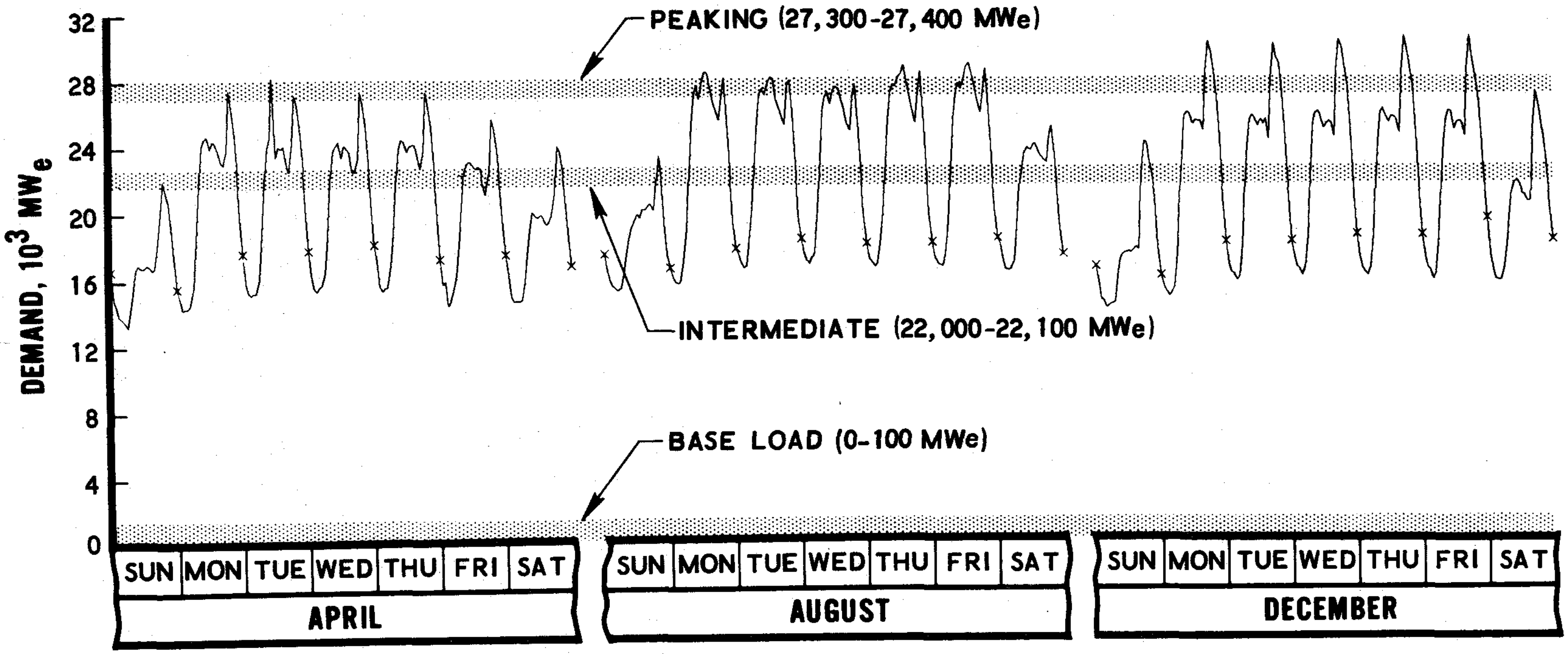


Figure 2-4. Electric Power Demand 1990, Southern California Edison Company

This demand is a projected hourly electrical load for the Southern California Edison service area during the year 1990 with a peak demand of 32,000 MWe.

2.5.2 Solar Thermal Conversion System Technical Characteristics

The technical characteristics incorporated in the performance simulations of the alternative solar thermal conversion concepts examined are summarized in Table 2-3. These subsystem design characteristics reflect preliminary point design studies of these alternative solar thermal conversion concepts conducted by other NSF system contractors. Additional performance design data can be incorporated when it becomes available.

The individual subsystem losses are computed from these design characteristics by means of efficiencies, unit heat losses, graphs, tables and computational subroutines. Pump power losses are simulated as a function of flow rate. The turbine/generator efficiencies shown reflect dry cooling operation. The terms "graphical winter perturbed", "tabular" and "calculated" refer to pre-programmed graphs, tables and computer subroutines incorporated to accurately match contractor defined performance for the related subsystems while minimizing computer costs for hourly simulation over an entire year.

Table 2-3. Solar Thermal Conversion Systems, Technical Characteristics

COMPARATIVE SUBSYSTEM DESCRIPTION	CENTRAL RECEIVER	PARABOLIC CYLINDER	PARABOLOIDAL DISH
COLLECTOR			
PRIME REFLECTIVITY	0.88	0.88	0.88
SECONDARY REFLECTIVITY	--	0.96	--
AIMING EFFICIENCY	(Graphical	CALC(1)	0.94(1)
SHADING	Winter-	TABULAR	TABULAR
TRACKING EFFICIENCY	Perturbed)	CALC	CALC
RECEIVER			
ABSORPTIVITY	0.90	0.90	0.85(1)
EMISSIVITY	0.95	--	--
SURFACE TEMP	538° C(1000° F)	--	--
UNIT HEAT LOSS	--	0.0472 KW_t/M^2	0.0126 KW_t/M^2
DISTRIBUTION PUMP			
PUMP CONSTANT(2)	66×10^{-3}	132×10^{-3}	132×10^{-3}
LINE THERMAL LOSS			
LINE EFFICIENCY	1.00	0.90	0.90
STORAGE			
INPUT/OUTPUT-EFFICIENCY	0.85	0.85	0.85
IN STORAGE LOSS	0.1 %/hr	0.1 %/hr	0.1 %/hr
TURBINE GENERATOR			
STEAM TEMP	482° C(900° F)	316° C(600° F)	427° C(800° F)
OVERALL EFFICIENCY(3)	0.36	0.32	0.34

(1) Simulate Honeywell Performance Results

(2) Pump Constant = Pump Power x $(\text{collector area})^2/(\text{pump flow rate})^3$

(3) Dry Cooling

2.5.3 Solar Thermal Conversion Subsystem Efficiencies

Solar plant performance for an entire year of operation was simulated for each of the alternative solar plant concepts using the subsystem characteristics defined in Table 2-3.

The performance simulations were based on a 100 MWe solar plant located at Inyokern, California, using the 1963 direct insolation data base developed for this station and using the Southern California Edison Company service area hourly demand forecast for the year 1990.

The resultant yearly average subsystem efficiencies are shown in Table 2-4 for each of the alternative configurations. The overall efficiency reflects all losses from insolation input to electric power output, and consequently, is of primary significance in comparing the various system concepts. The overall efficiency does not include waste heat or storage losses as these are a function of the particular operational mode considered.

As can be seen from Table 2-4, the central receiver concept has the highest overall efficiency (19.2%), and the E-W oriented parabolic cylindrical trough the lowest (11.1%).

2.5.4 Base Load Solar Plant - Operating Characteristics

Some of the results of actual simulation of a central receiver 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 chart 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 100 MWe rated generator central receiver power

Table 2-4. Solar Thermal Conversion Systems, Subsystem Efficiencies

SUBSYSTEMS	CENTRAL RECEIVER	PARABOLIC CYLINDRICAL TROUGH			PARABOLOIDAL DISH
		POLAR	N-S	E-W	
COLLECTOR					
TRACKING	0.703	0.957	0.876	0.724	1.000
AIMING		0.945	0.918	0.849	0.940
SHADING		0.867	0.888	0.978	0.860
BLOCKING		--	--	--	--
FIRST REFLECTIVITY	0.880	0.880	0.880	0.880	0.880
SECOND REFLECTIVITY	--	0.960	0.960	0.960	--
RECEIVER					
ABSORPTIVITY	0.900	0.900	0.900	0.900	0.850
THERMAL LOSSES	0.970	0.895	0.884	0.873	0.972
DISTRIBUTION PUMP LOSSES	0.985	0.970	0.970	0.970	0.962
DISTRIBUTION LINE THERMAL LOSSES	1.000	0.900	0.900	0.900	0.900
TURBINE/GENERATOR	0.360	0.320	0.320	0.320	0.340
OVERALL EFFICIENCY[1]	0.192	0.149	0.134	0.111	0.173

[1] Does not include Waste Heat or Storage Losses

Base Load Solar Thermal Conversion Plant (100 mW_e)

OPERATING CHARACTERISTICS

- CENTRAL RECEIVER CONCEPT (winter orientation)
- CONCENTRATING COLLECTOR AREA 2 KM^2
- THERMAL STORAGE 12 hr
- INYOKERN, CALIFORNIA

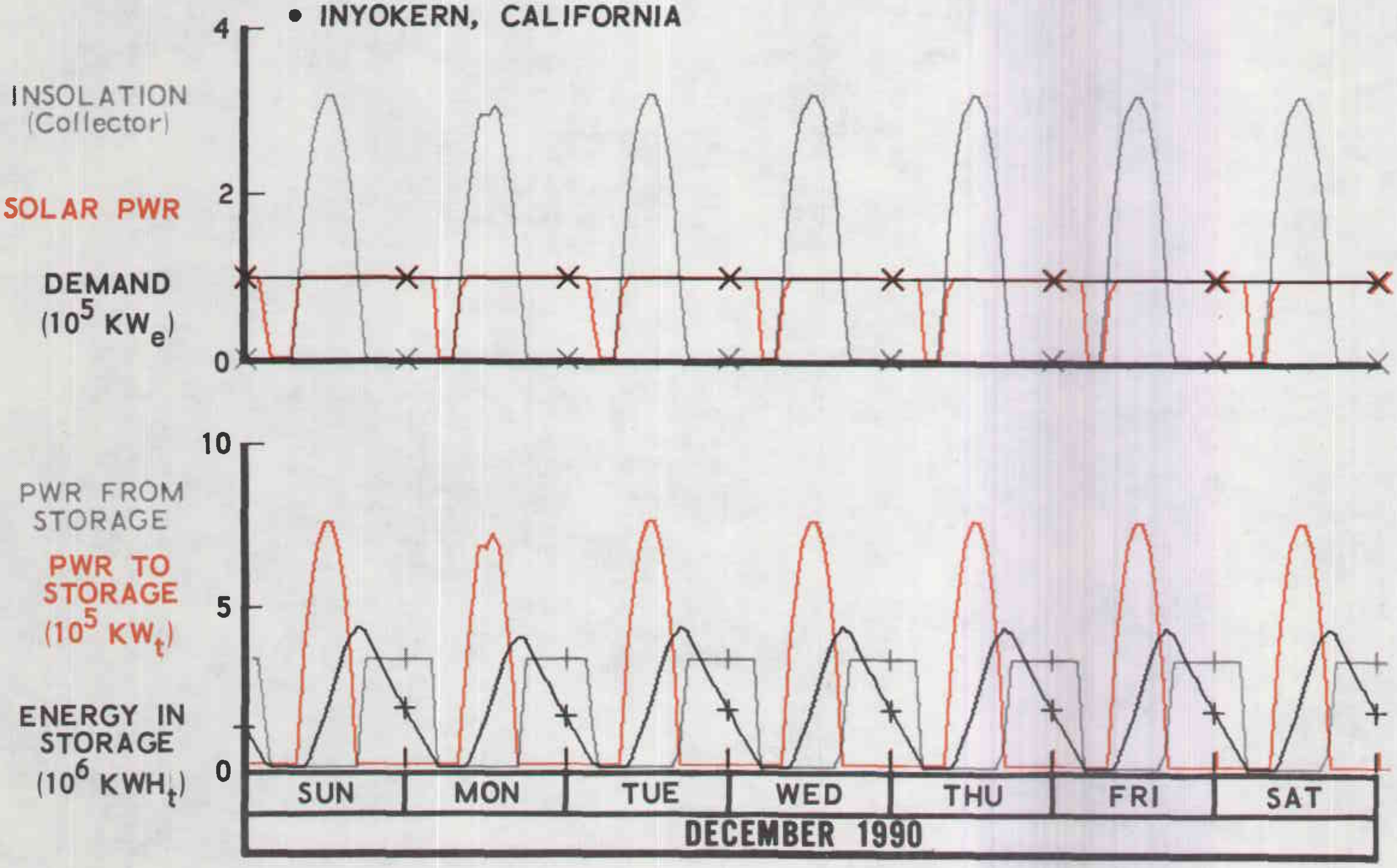


Figure 2-5. Base Load Solar Thermal Conversion Plant Operating Characteristics

plant with a 2 Km^2 collector area and a 12-hour storage capacity.

The top figure shows the relationship between the 100 MWe base load electrical demand (100 MWe line), the power output of the turbine/generator to meet this demand (line between 0 and 100 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 turbine/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 turbine/generator (trapezoidal-shaped curves), and energy available in storage (triangular-shaped curves).

As can be seen, power not used by the turbine/generator during sunshine hours flows to storage, thereby increasing the energy in storage. During nonsunshine hours, the turbine/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.

2.5.5 Base Load Central Receiver Power Plant Technical Performance

Simulation of a 100 MWe central receiver system operating in the base load mode was performed for a parametric combination of collector areas and storage capacities. The performance results, based on a full year of hourly simulation, are summarized in carpet plot format in Figure 2-6.

- TURBINE-GENERATOR RATING ~ 100 MW_e (η_{TG} = .36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990

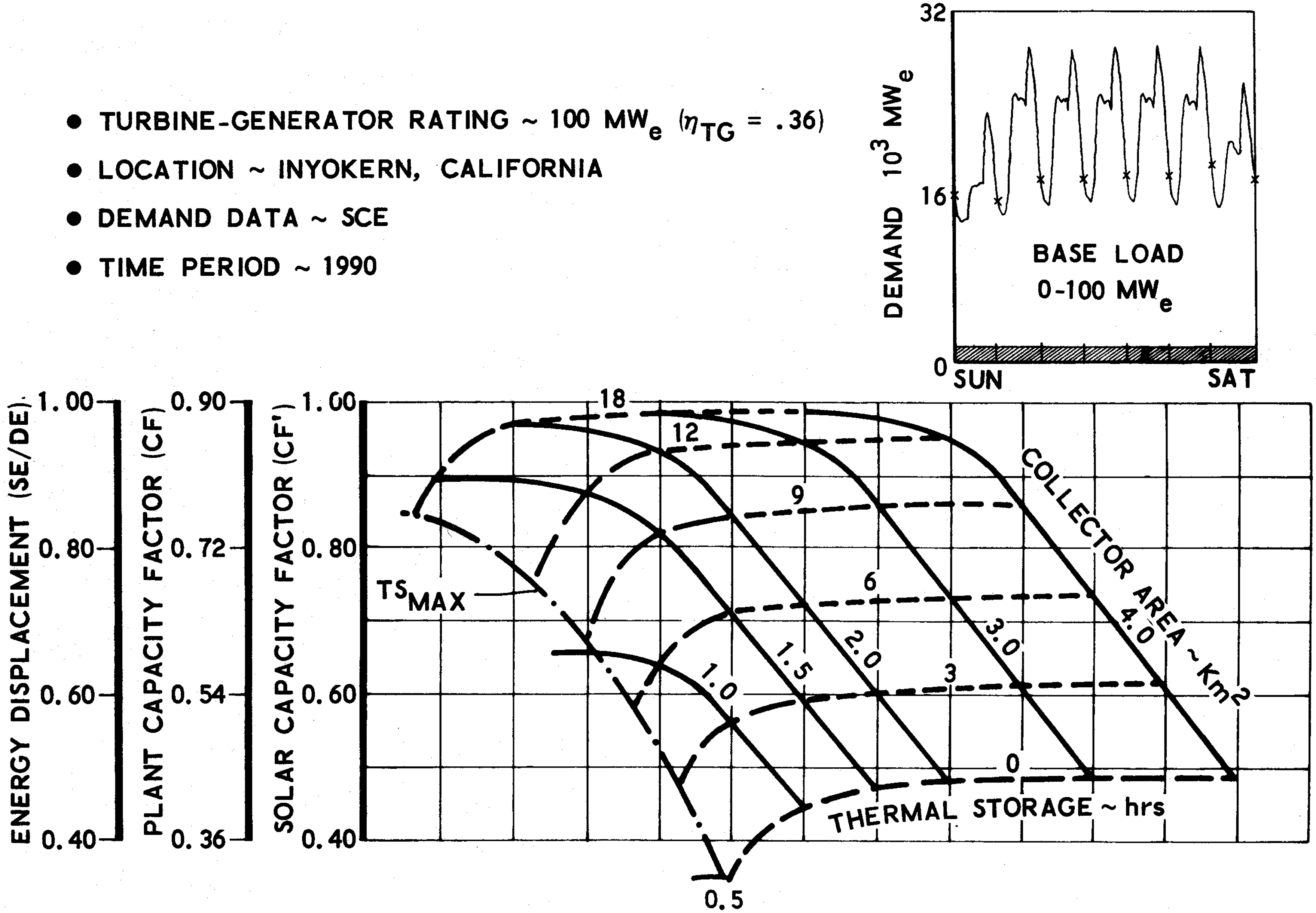


Figure 2-6. Base Load Solar Thermal Conversion Plant Central Receiver (Winter Perturbed)

The solar capacity factor, plant capacity factor and energy displacement are shown for different combinations of solar collector areas and storage capacities while maintaining a constant turbine/generator rating. The solar capacity factor is the actual turbine/generator energy output, integrated over the year, divided by the maximum theoretical total output for the year. 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 turbine/generator output divided by the total demand energy for the year (1990). Since the base load demand is always equal to 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 the performance of a solar power plant in meeting the specified demand and therefore provides an estimate of the solar power plant outage rate. The outage rate is necessary to determine the capacity displacement of solar plants when substituted for conventional plants in a total power grid system, as will be discussed in the margin analysis section (Section 3). The plant capacity factor provides a measure of actual useful electrical energy delivered per year by the solar power plant. The combination of generated energy and capacity displacement are important inputs to the economic evaluation of solar power plants as will be discussed in the following section.

As indicated in Figure 2-6 for a particular collector area, such as 1.5 km^2, a significant improvement in performance is attained by increasing storage capacity. Beyond about 18 hours of storage, however, this improvement has diminishing returns and little improvement in performance can be attained for this particular collector area. At this point, the collector area is too small to add additional energy to storage. This limit condition of maximum storage is shown in the figure by the near vertical dot-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.

As can be seen from Figure 2-6, a 100 MWe base load central receiver system with a collector area of 1.5 km^2 and 12-hours storage capacity, located in Inyokern, California, attains a plant capacity factor of 79 percent. This case has an energy displacement of almost 90 percent (and a corresponding unscheduled outage of approximately 10 percent).

2.5.6 Base Load Paraboloidal Dish - Power Plant Technical Performance

The parametric technical performance characteristics for an 100 MWe base load paraboloidal dish solar plant are shown in Figure 2-7.

As compared with the base load central receiver plant, the performance in terms of plant capacity factor and energy displacement is slightly less for equivalent combinations of collector area and storage capacity. These data are based upon a full year of hourly simulation, with identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Table 2-3 which were derived from system studies conducted by other NSF contractors.

2.5.7 Base Load Parabolic Cylinder Power Plant Technical Performance

The parabolic cylindrical-trough collector concepts were investigated for three different orientations: polar, north-south, and east-west. Figures 2-8 through 2-10 show the parametric technical performance characteristics for 100 MWe base load solar plants incorporating these alternative collector concepts.

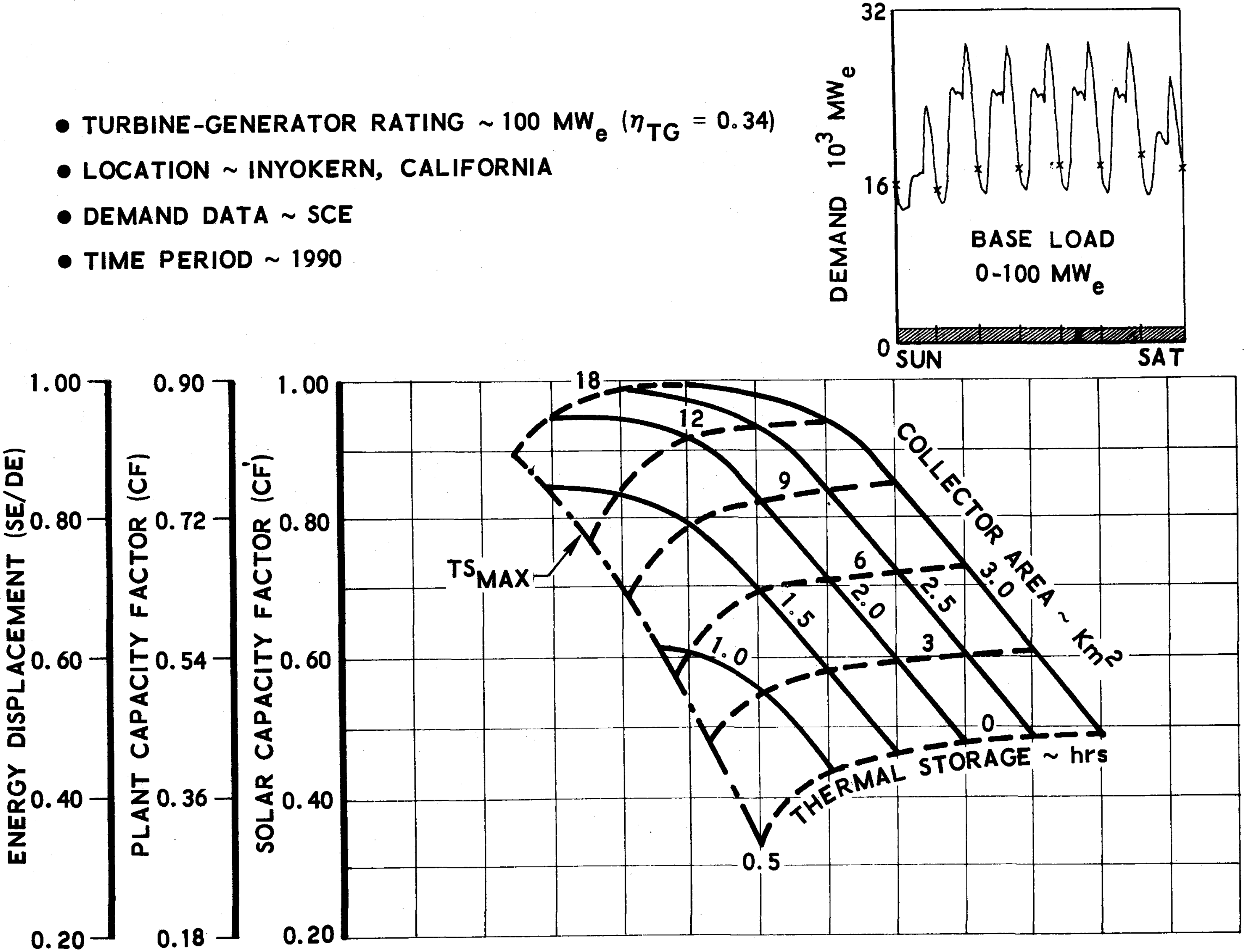


Figure 2-7. Base Load Solar Thermal Conversion Plant Paraboloidal Dish

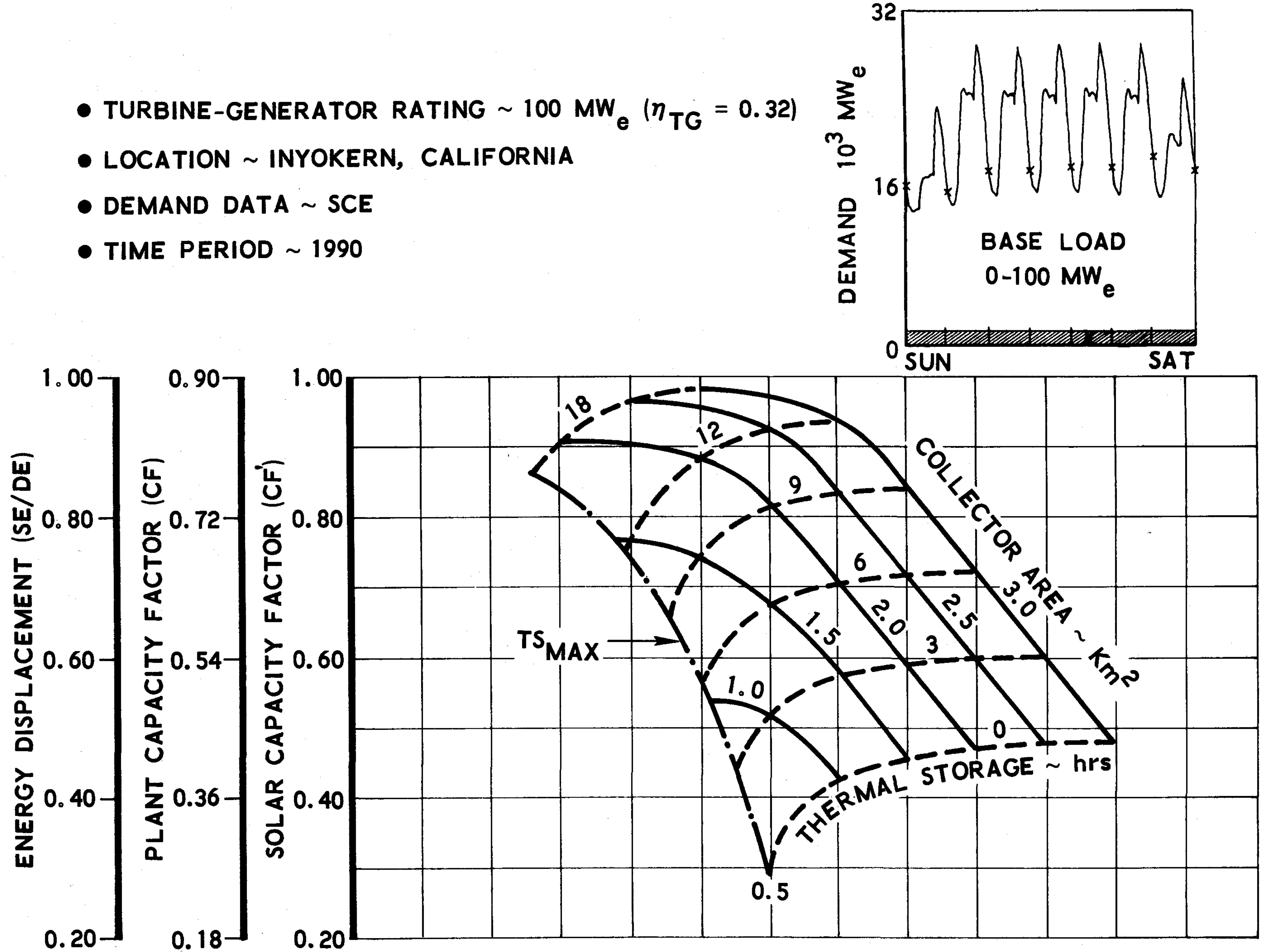


Figure 2-8. Base Load Solar Thermal Conversion Plant Polar Parabolic Cylinder

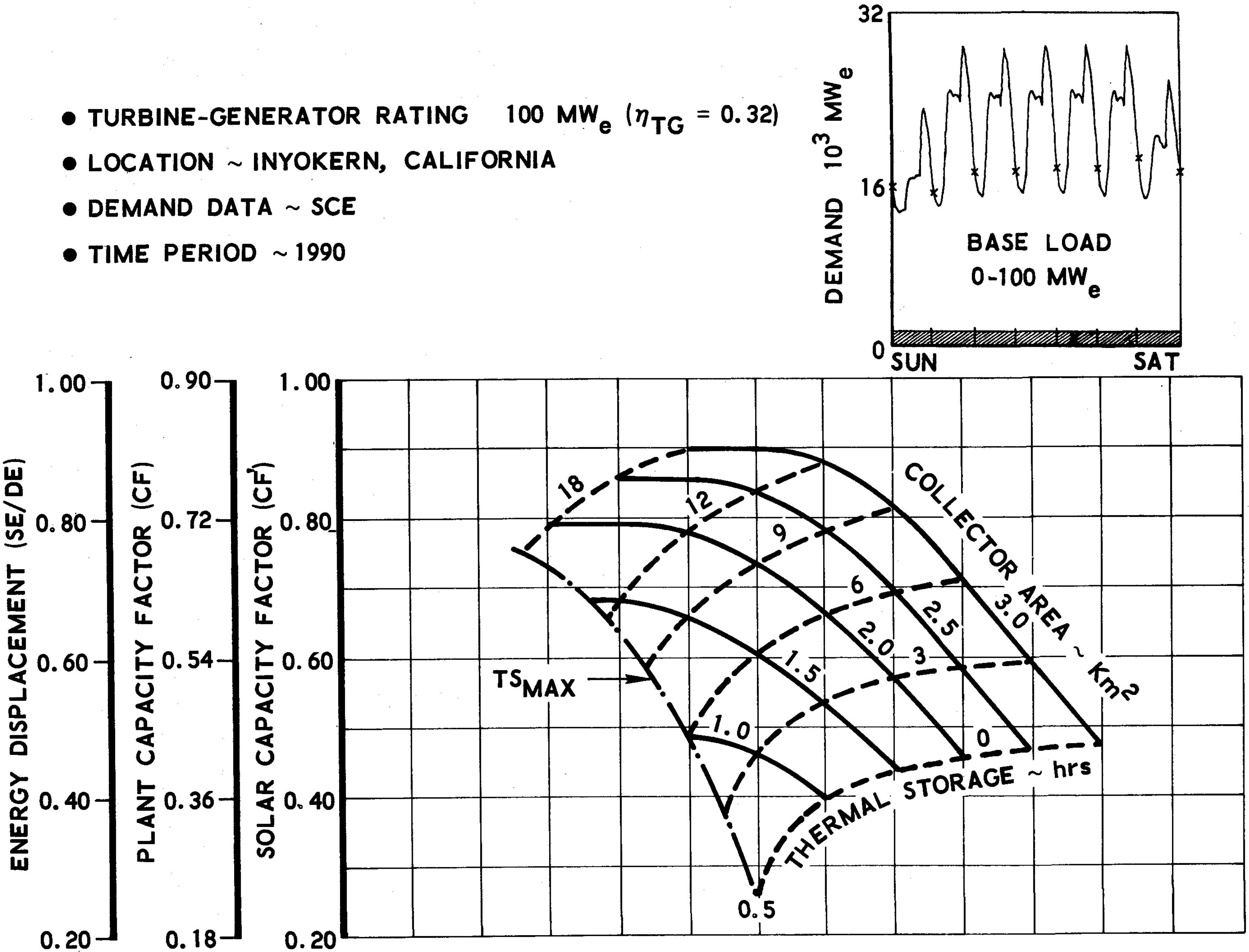


Figure 2-9. Base Load Solar Thermal Conversion Plant N-S Parabolic Cylinder

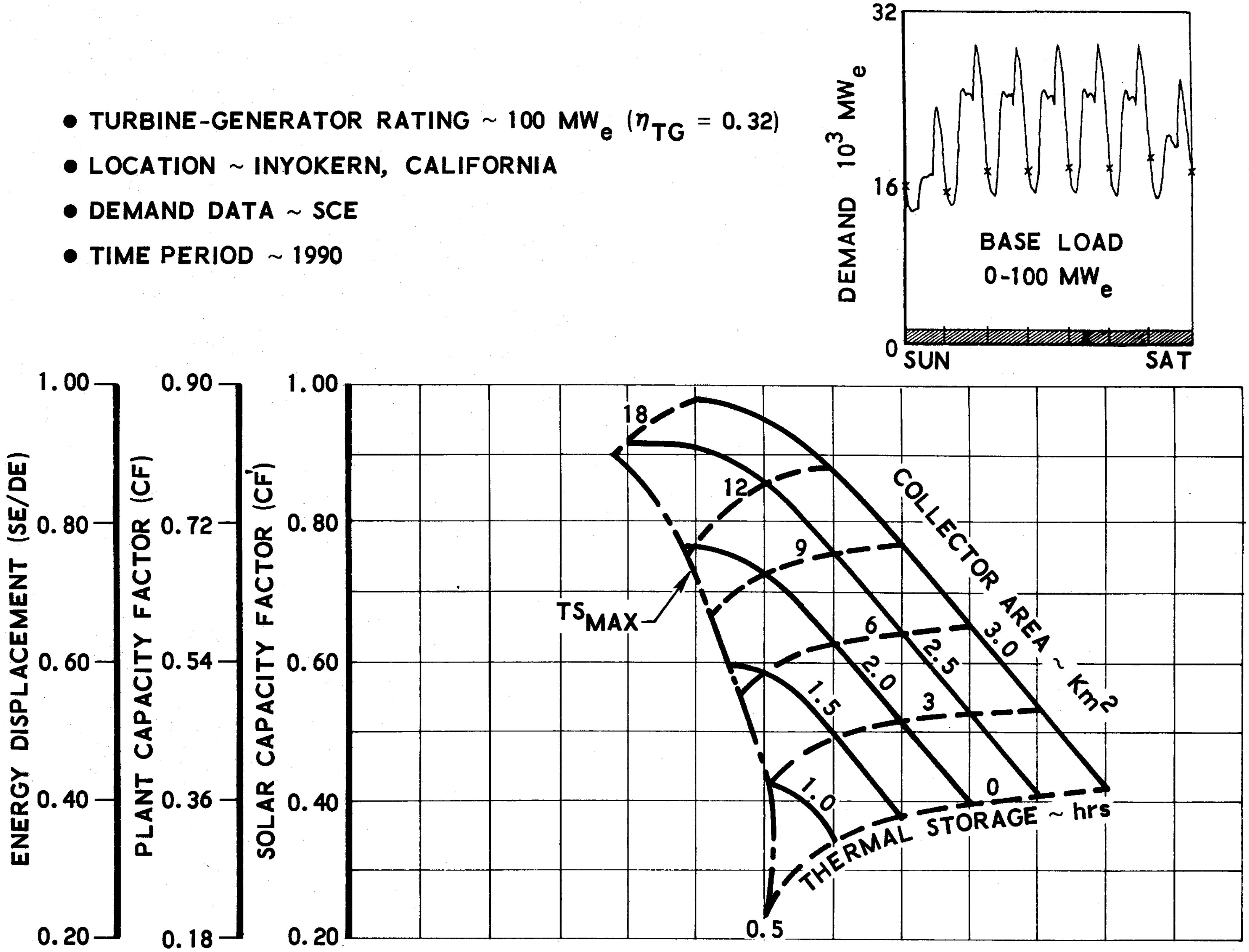


Figure 2-10. Base Load Solar Thermal Conversion Plant E-W Parabolic Cylinder

As for the other plants, these data are based upon a full year of hourly simulation with identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Table 2-3, which were derived from system studies conducted by other NSF contractors.

As compared with the central receiver and paraboloidal dish power plants, all three parabolic cylindrical trough concepts have lower performance characteristics. The polar-oriented plant has the highest performance of the three parabolic trough concepts, and the E-W oriented plant the lowest

Performance of the N-S parabolic cylinder plant is severely restricted at winter solstice due to its inability to track the sun in the elevation. rection. This results in a deterioration in performance below that exhibited by the polar-oriented parabolic cylinder (on a yearly integrated basis) for all combinations of collector area and storage capacity.

Performance of the E-W parabolic cylinder plant is restricted by an inability to track the sun in azimuth, which strongly affects the morning and late afternoon efficiency, but results in a more level performance over the entire year than exhibited by the N-S oriented parabolic cylinder concept.

The relative economic merits of the various combinations of collector areas and storage capacities for these system concepts are the subject of the economic and financial analyses summarized in Section 4.

2.5.8 Intermediate Load Central Receiver Power Plant Technical Performance

The parametric technical performance characteristics for an intermediate load central receiver solar power plant, based upon a full year of hourly simulation, are shown in Figure 2-11.

For the 100 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 2-11 are the solar capacity factor, plant capacity factor, and energy displacement for various combinations of collector area and storage capacity, when operating within the 22,000-22,100 MWe intermediate demand range.

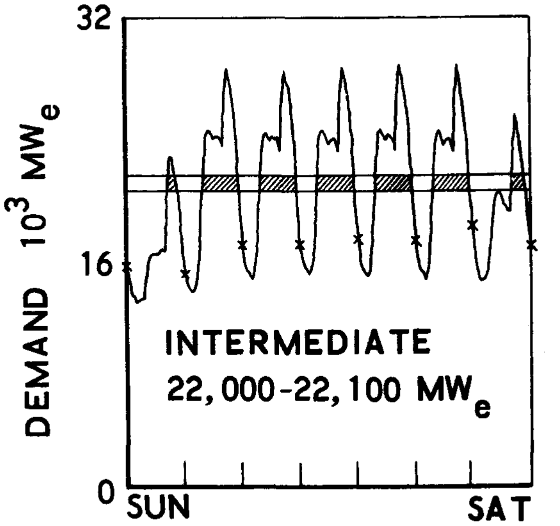
Again, the plant capacity factors were assumed to be 90 percent of the solar capacity factor, assuming a 5-week per year (10 percent) scheduled maintenance period.

The energy displacement within the 22,000-22,100 MWe intermediate demand range is the integrated turbine/generator energy output divided by the integrated energy demand within the range, which is different from the solar capacity factor in this case.

The energy displacement is a measure of the unscheduled outage characteristics, which in turn provides a measure of the capacity displacement potential.

As can be seen from Figure 2-11, the storage requirements for intermediate load solar plant applications are much smaller than for base load operation.

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



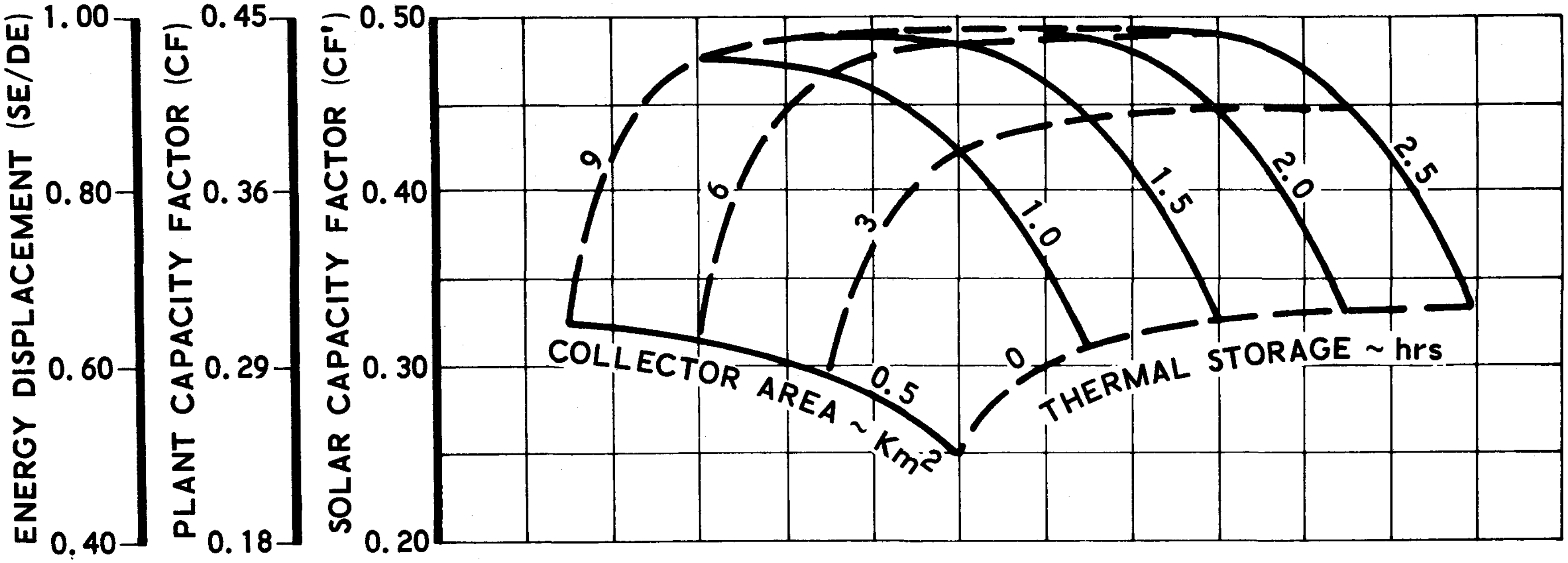


Figure 2-11. Intermediate Solar Thermal Conversion Plant Central Receiver (Winter Perturbed)

In the intermediate operating mode there may be situations for certain combinations of collector area and storage where solar plant power is available and storage is full during periods of low or zero demand within the 22,000-22,100 MWe range. Because of the low marginal cost of solar energy once the solar plant has been built (because of zero fuel cost), the solar plant 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 was calculated for the various combinations of collector area and storage capacity analyzed.

For certain combinations of large collector areas and small storage capacity the turbine/generator with a rating of 100 MWe cannot handle all the insolation energy available; consequently, this energy was assumed to be lost.

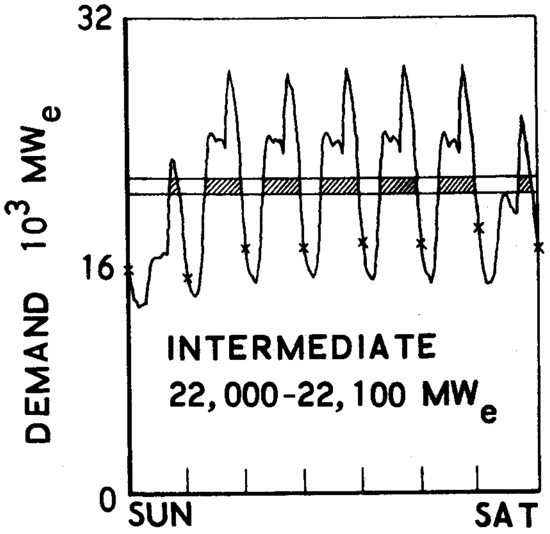
In the economic assessment of the intermediate mode solar power plants credit was taken for the displacement of conventional plant base load fuel only, since no capacity displacement in the base load region was assumed.

2.5.9 Intermediate Load Paraboloidal Dish Power Plant Technical Performance

The parametric technical performance characteristics for an 100 MWe intermediate load paraboloidal dish solar plant are shown in Figure 2-12.

As compared with the intermediate load central receiver plant, the performance in terms of plant capacity factor and energy displacement is slightly less for equivalent combinations of collector area and storage capacity.

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .34)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



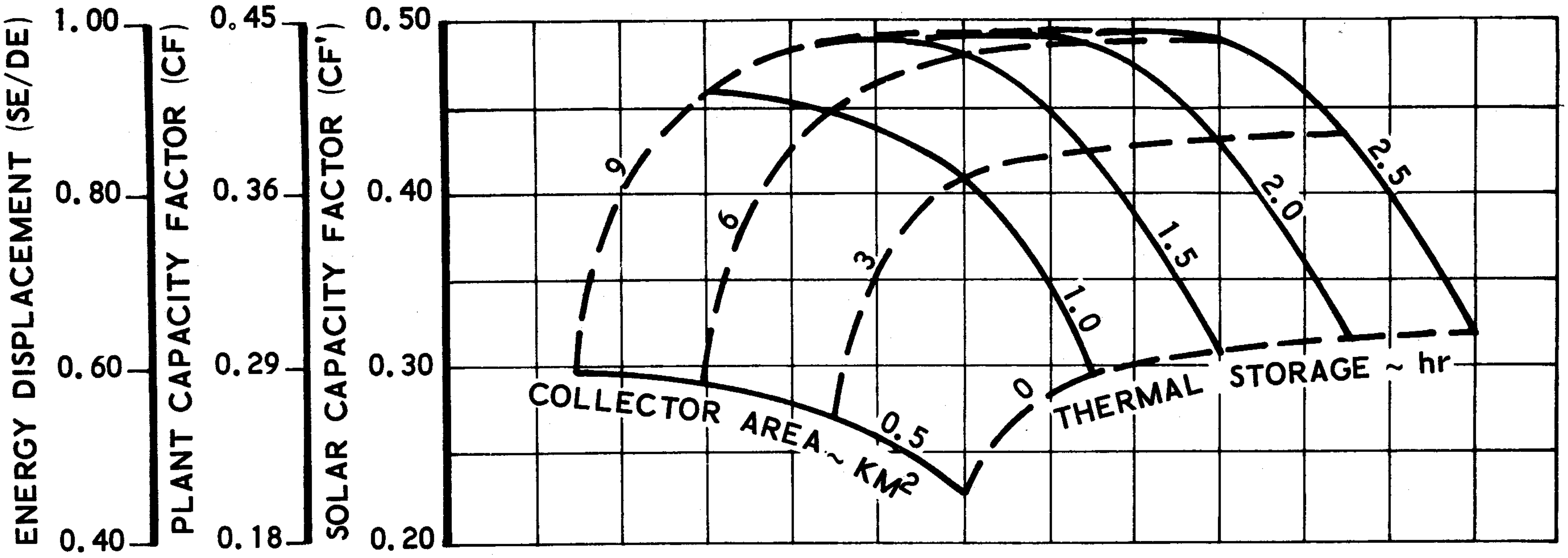


Figure 2-12. Intermediate Solar Thermal Conversion Plant Paraboloidal Dish

These data are based upon a full year of hourly simulation, with identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Table 2-3, which were derived from system studies conducted by other NSF contractors.

Even though peaking solar plants were also analyzed, the intermediate load or load-following operational mode was determined to be preferred, and consequently, the comparative technical evaluation of the alternative concepts is shown for the base and intermediate operating modes only.

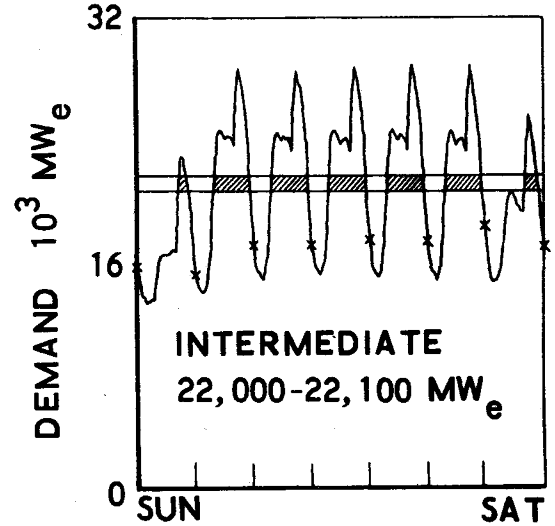
2.5.10 Intermediate Load Parabolic Cylinder Power Plant Technical Performance

The parabolic cylindrical-trough collector concepts were investigated for three different orientations: polar, north-south, and east-west. Figure 2-13 through 2-15 show the parametric technical performance characteristics for 100 MWe intermediate load solar plants incorporating these alternative collector concepts.

As for the other plants, these data are based upon a full year of hourly simulation, with identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Table 2-3 which were derived from system studies conducted by other NSF contractors.

As compared with the central receiver and paraboloidal dish power plants, all three parabolic cylindrical trough concepts have lower relative performance characteristics. The polar-oriented plant has the highest performance of the three parabolic trough concepts, and the E-W oriented plant the lowest.

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



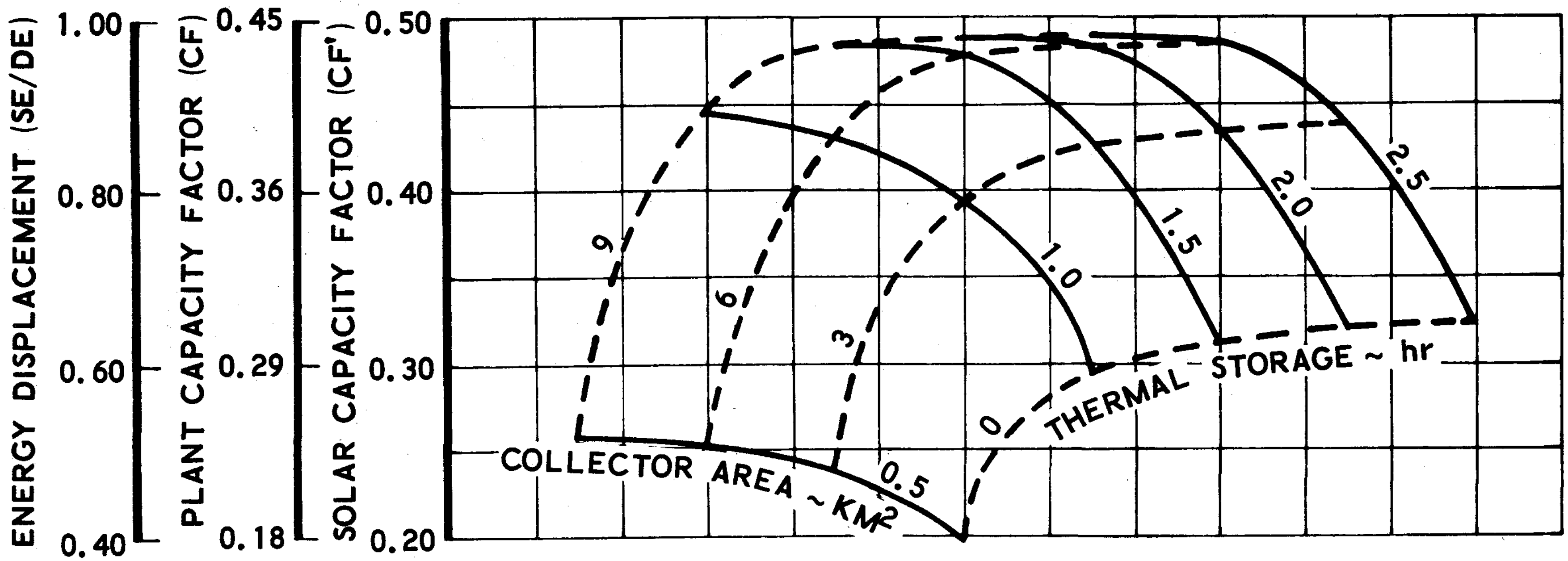
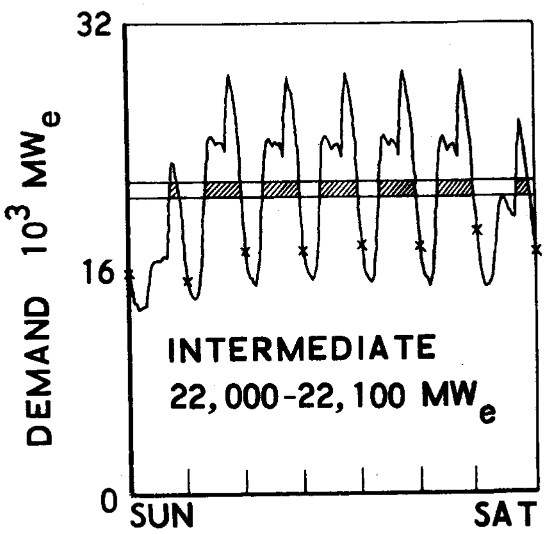


Figure 2-13. Intermediate Solar Thermal Conversion Plant Polar Parabolic Cylinder

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



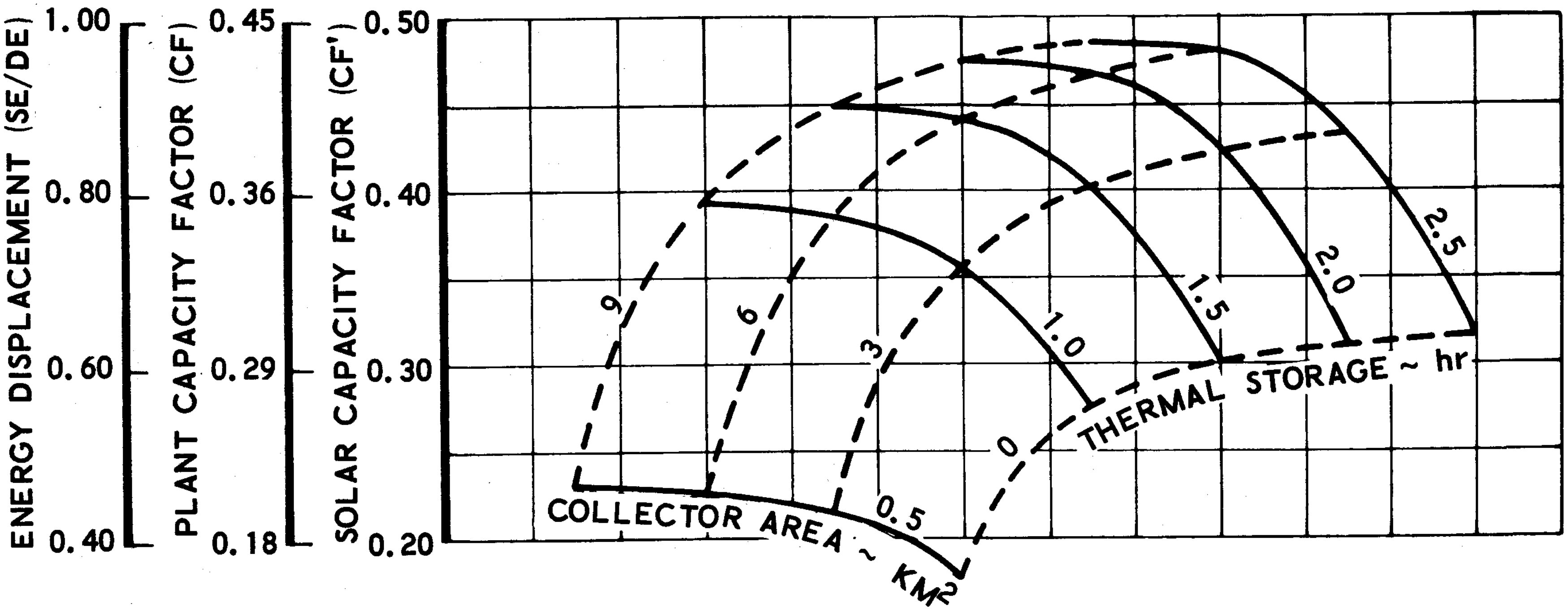
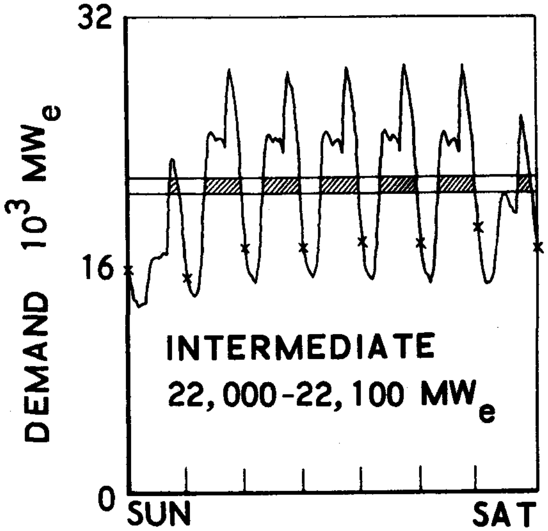


Figure 2-14. Intermediate Solar Thermal Conversion Plant N-S Parabolic Cylinder

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



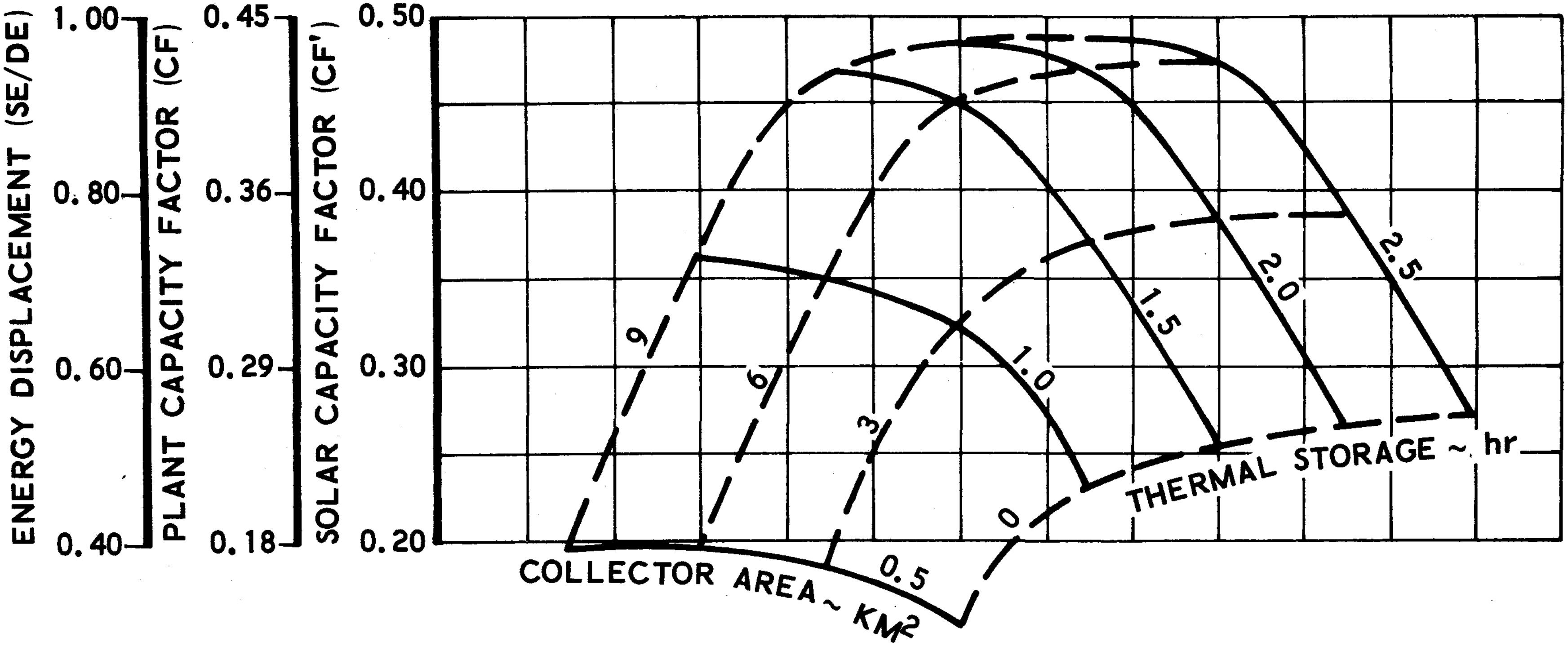


Figure 2-15. Intermediate Solar Thermal Conversion Plant E-W Parabolic Cylinder

Performance of the N-S parabolic cylinder plant is severely restricted at winter solstice due to an inability to track the sun in the elevation rection. This results in a deterioration in performance below that exhibited by the polar oriented parabolic cylinder (on a yearly integrated basis), for all combinations of collector area and storage capacity.

Performance of the E-W parabolic cylinder plant is restricted by an inability to track the sun in azimuth, which strongly effects the morning and late afternoon efficiency, but results in a more level performance over the entire year than exhibited by the N-S oriented parabolic cylinder concept.

2.5.11 Peaking Load Central Receiver Power Plant Technical Performance

The peaking mode of operation was simulated for the central receiver concept and the parametric technical performance characteristics are shown in Figure 2-16. The collector area and storage capacity were varied parametrically for the solar plant with a fixed 100 MWe generator rating.

Shown in Figure 2-16 are the plant capacity factor and energy displacement for the various combinations of collector area and storage capacity when operating within the 27,300-27,400 MWe peak demand range.

The plant capacity factor is the same as the solar capacity factor (not shown), since maintenance for this case can be scheduled during periods in the year where no demand exists within the defined peak demand range, as can be seen in Figure 2-4.

For these peaking solar plants solar energy may be available during periods of low or zero peak load demand within the 27,300-27,400 MWe range. Because of the low marginal cost of this electrical output, the

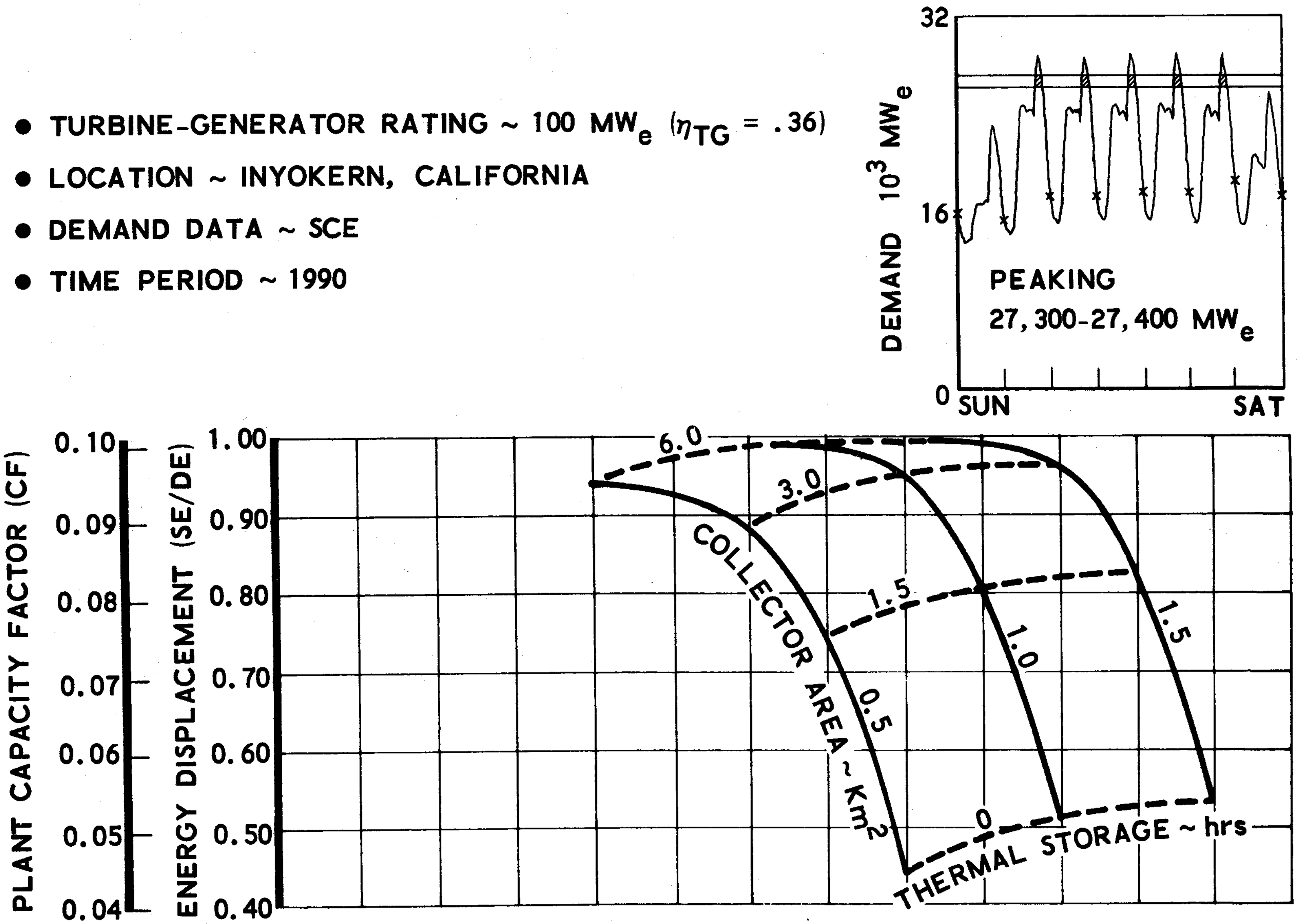


Figure 2-16. Peaking Solar Thermal Conversion Plant Central Receiver (Winter Perturbed)

solar plant was assumed to continue operating during these periods to displace intermediate and base load energy. Again no capacity displacement was assumed for this additional energy displacement. Thus the plant essentially operates in a load-following mode, with only capacity displacement assumed within the specified peak demand range of 27,300-27,400 MWe. Those collector-area and storage-capacity combinations where the solar energy available is in excess of the turbine/generator rating and storage capability represent the maximum intermediate and base load energy displacement potential.

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.

2.5.12 Comparative Technical Solar Thermal Conversion System Performance

A relative technical performance comparison of the alternative solar thermal conversion systems: central receiver; paraboloidal dish; and three parabolic cylinder concepts for base and intermediate load operation is shown in Table 2-5. The technical performance of the alternative system concepts was determined on a consistent basis using the systems methodology and input data previously described. The comparisons are made on the basis of the collector area required to achieve equivalent technical performance for a fixed storage capacity.

As can be seen from this figure, the central receiver system requires the smallest collector area and the parabolic cylindrical trough systems the largest. Though the central receiver system appears preferred on the basis of performance, a final selection must await the comparative economic evaluation, which incorporates the various solar plant costs as well as the performance attributes prior to identifying preferred

Table 2-5. Solar Thermal Conversion Systems, Technical Evaluation, Equivalent Plant Performance

- PLANT CAPACITY ~100 MWe
- LOCATION ~INYOKERN
- DEMAND DATA ~SCE 1990

SYSTEM	COLLECTOR AREA REQUIRED ~ KM^2	
	BASE LOAD 12 hr STORAGE	INTERMEDIATE LOAD 6 hr STORAGE
CENTRAL RECEIVER	1.5	1.0
PARABOLIC CYLINDER		
POLAR	~2.0	~1.3
NORTH-SOUTH	~3.0	~2.0
EAST-WEST	~3.0	~2.0
PARABOLOIDAL DISH	~1.8	~1.2

system concepts.

The analyses described in this section illustrate the application of the system simulation methodology. The technical performance of alternative solar thermal conversion concepts 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 alternative solar power plant concepts become available, these design characteristics will be incorporated in future system analyses.

2.5.13 Central Receiver Subsystem Performance

Evaluating the performance of a solar plant involves a close determination of the individual subsystem losses. A representation of these losses, for a central receiver system operating in the intermediate demand range, is presented in Figure 2-17. These results are based on a full-year hourly simulation of a central receiver power plant with a 100 MWe rated generator capacity, operating in the intermediate mode, with a collector area of 1 km^2, a 6-hour storage capacity, and located at Inyokern, California.

All subsystem losses are referenced to the direct insolation incident on the total collector area, which reflects the theoretical maximum energy available. The tracking, shading, and blocking losses, for example, represent a 29.7 percent loss of total available insolation energy. The reflectivity losses represent a further 8.4 percent loss in total available energy based on an 88 percent reflectivity.

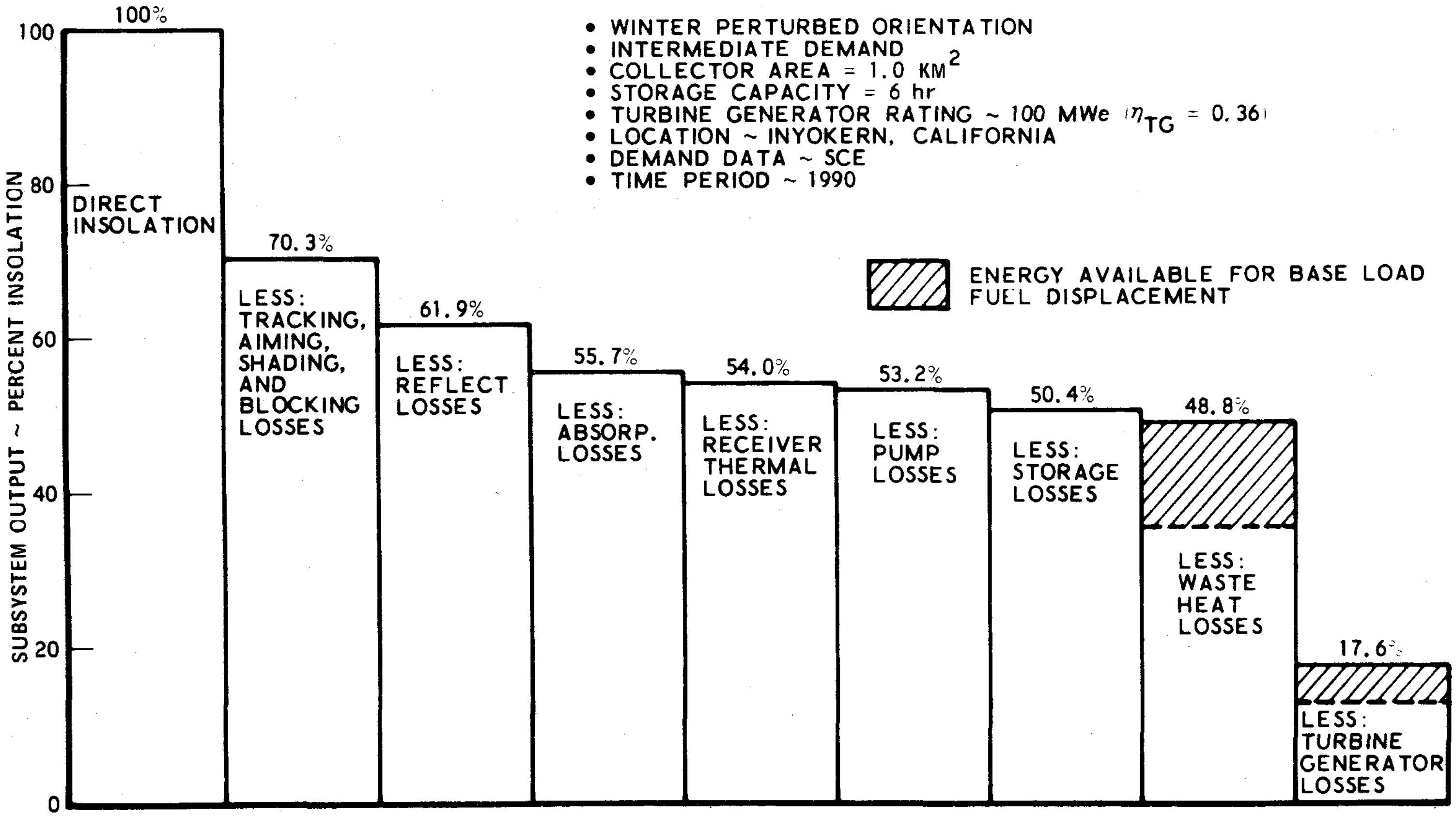


Figure 2-17. Central Receiver System Performance

The cross-hatched areas reflect energy available for base load fuel displacement. This energy is above that required to satisfy the intermediate demand and provides a total utility system cost benefit in terms of fuel savings even though no capacity displacement credit has been assumed in the base load region.

2.5.14 Intermediate Solar Plant Relative Siting Performance

Solar plant performance is directly dependent on the available insolation which varies according to the specific site selected. Insolation data bases were formulated for twenty separate stations representative of the climatic regions in the Southwestern United States as described in a previous section. The performance of a representative central receiver system, operating in the intermediate mode, was simulated at each of these separate sites. The relative performance at these various sites is compared in Figure 2-18 to a reference plant located at Inyokern, California.

As can be seen from this figure, the maximum performance variation on the basis of a complete year simulation for the twenty different sites is less than 20 percent. Elimination of the lower insolation sites such as Fresno, California; Salt Lake City, Utah; Fort Worth, Texas; and Omaha, Nebraska reduces the maximum performance variation to approximately 11 percent. Furthermore, solar power plants located at Inyokern, and Edwards AFB in California; Yuma, Phoenix, and Tuscon in Arizona; Albuquerque, New Mexico; and El Paso, Texas, have nearly identical performance characteristics.

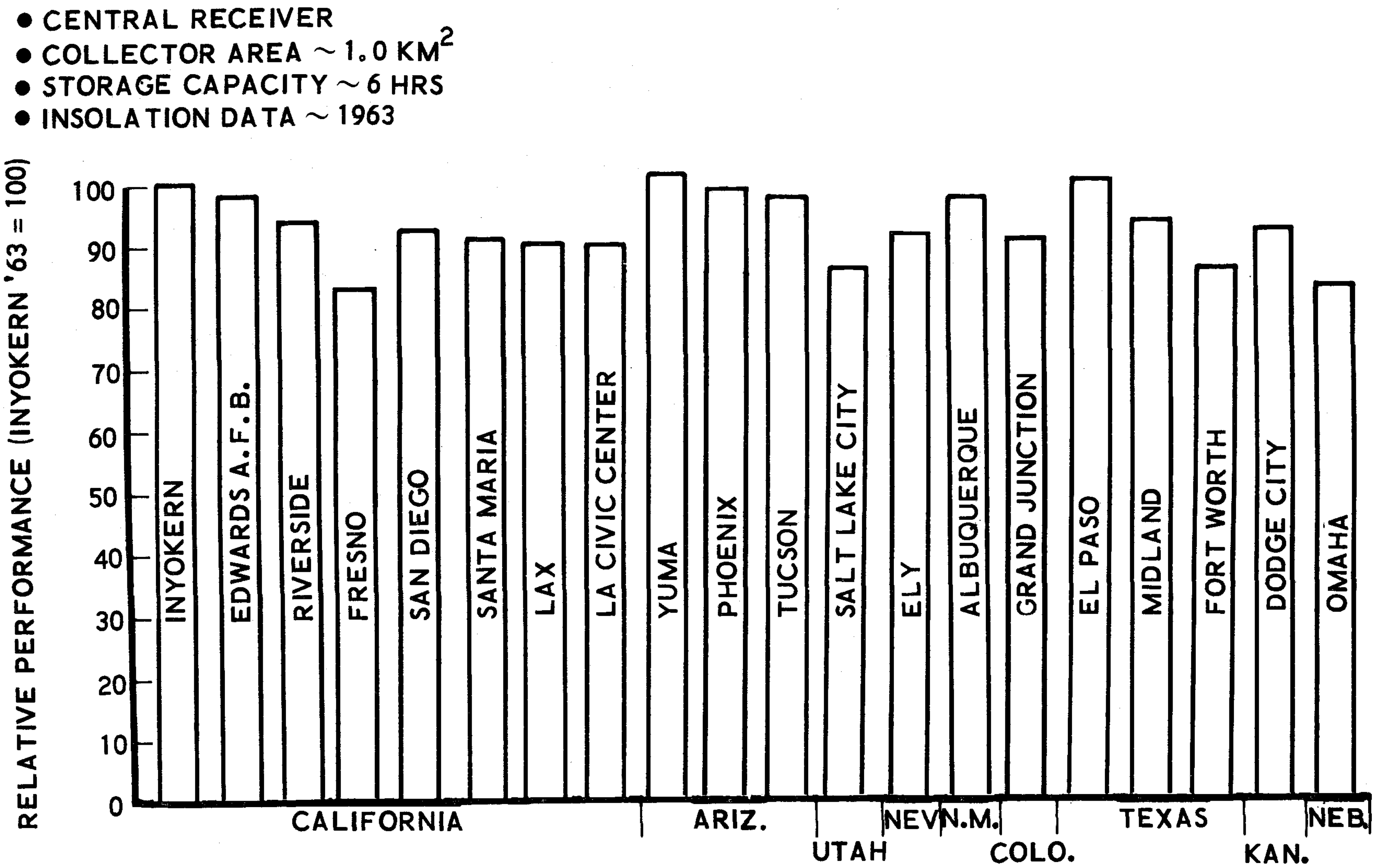


Figure 2-18. Intermediate Solar Thermal Conversion Plant Relative Performance (Inyokern, 1963 = 100)

2.5.15 Solar Plant Geographic Dispersion

Periods of cloud cover resulting in little or no insolation may result in forced outages of solar plants depending upon the energy storage capacity provided. Geographical dispersion of plants at statistically independent weather sites has been suggested as a means of reducing the impact of solar plant outages on the total power grid.

Table 2-6 presents the comparative performance simulation results of individual solar plants operating independently at Inyokern, California or Yuma, Arizona with two dispersed but jointly operating solar plants located at each of these sites. The individual power plants are sized for 100 MWe rated generator capacity, with a 1.0 km^2 collector area and 6-hour storage capacity. The jointly operating dispersed plants were each sized for 50 MWe rated generator capacity, 0.5 km^2 collector area and 6-hour storage capacity (one-half the 100 MWe, 6-hour thermal capacity). All simulations were performed hourly for an entire year, with the solar plants operating in the intermediate (22,000-22,100 MWe) demand range.

The performance results of each of the individual plants were compared with the joint performance of the dispersed plants to determine the relative advantages of solar plant dispersion. The outage rate of the dispersed plants is 5.6% which is the average of the single plants operating independently at Inyokern and Yuma (i.e. 6.4% and 4.8%). This indicates that solar plant dispersions average out the better and poorer site locations rather than improves the overall system performance. Each of the dispersed plants individually can supply only 50 percent of the combined 100 MWe demand; consequently, when either plant has a forced outage only one-half of the demand can be met. This generally accounts for the averaging effect of these dispersed plants.

Table 2-6. Central Receiver System Performance, Solar Plant Geographic Dispersion

- INTERMEDIATE SOLAR THERMAL CONVERSION PLANT
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- TURBINE GENERATOR EFFICIENCY $\sim \eta_{TG} = 0.36$

SOLAR PLANT CHARACTERISTICS	SINGLE SOLAR PLANT		DISPERSED SOLAR PLANTS	
PLANT LOCATION	INYOKERN	YUMA	INYOKERN	YUMA
PLANT SIZE				
TURBINE/GEN. RATING	100 MWe		50 MW_e	
COLLECTOR AREA	1.0 Km^2		0.5 Km^2	
STORAGE CAPACITY	6 hrs		6 hrs*	
SOLAR PLANT PERFORMANCE				
PLANT CAPACITY FACTOR	0.419	0.427	0.423	
SOLAR PLANT OUTAGE	6.4%	4.8%	5.6%	

*50% thermal energy capacity of single 100 MW_e solar plant

2.5.16 Central Receiver System Performance Sensitivity Analysis

The overall performance of a solar plant is subject to the individual characteristics of the various subsystems. Sensitivity analyses were performed for a central receiver system operating in the intermediate mode to determine the impact of varying subsystem characteristics on overall system performance.

The sensitivity was assessed by noting the performance variations from nominal on a subsystem basis. The sensitivity results are presented in Table 2-7, in terms of solar plant capacity factor and busbar energy cost deviations.

As can be seen in this table, the system performance is not overly sensitive to the anticipated changes in subsystem characteristics. The maximum deviations in solar plant capacity factor result from changes in receiver absorptivity and turbine/generator efficiency. The sensitivity in either parameter is represented by a 1.9 percent improvement (2.8 percent degradation) in plant capacity factor due to a 10 percent increase (decrease) in the system parameter. These same results also represent the sensitivity for similar percentage changes in insolation or collector efficiencies as these parameters impact overall system efficiency in a similar manner. The other subsystem uncertainties display a decidedly reduced impact on overall system performance. It should be noted that the receiver temperature sensitivity shown reflects only the change in re-radiative and convective losses and does not include the effect on turbine/generator performance due to different inlet steam temperatures.

Table 2-7. Central Receiver System (Winter Perturbed), Technical and Economic Sensitivity Analysis

- INTERMEDIATE DEMAND
- COLLECTOR AREA ~1.0 kM^2
- STORAGE ~6 hr

SUBSYSTEM	SUBSYSTEM NOMINAL PERFORMANCE	SUBSYSTEM PERFORMANCE VARIATIONS	SYSTEM SENSITIVITY	
			CAPACITY FACTOR	BUSBAR COST 1991 mills/kWh
COLLECTOR/RECEIVER: ABSORPTIVITY*	90%	99%(+10%) 81%(-10%)	+1.9% -2.8%	-0.9 +1.3
RECEIVER: SURFACE TEMP	538°C(1000°F)	1200°F(+20%) 800°F(-20%)	+0.4% +0.4%	-0.2 +0.2
DISTRIBUTION PUMP POWER	0.5 MW_e(max)	1.0 MW_e(+100%) 0.25 MW_e(-50%)	+0.2% -0.2%	-0.1 +0.1
STORAGE INPUT EFFICIENCY	85%	100%(+18%) 70%(-18%)	+1.1% -1.3%	-0.5 +0.6
TURBINE/GENERATOR EFFICIENCY	36%	39.6%(+10%) 32.4%(-10%)	+1.9% -2.8%	-0.9 +1.3

*Similar Effects Result from percent changes to collector efficiencies

3. MARGIN ANALYSIS

3.1 INTRODUCTION

In order to ensure that the electrical demand does not exceed the available generating capacity, the installed generating capacity for United States utility companies is designed to be in excess of the anticipated peak loads. The incremental generating capacity over peak load is called the margin. A margin analysis determines the excess electrical generating capacity required above the anticipated peak load in order to provide reliable service to the public during periods when forced outages are experienced at some generating stations. The margin requirements for utility systems arise due to unscheduled outages at particular generating plants. Unscheduled outages for conventional plants are due to component failures, while for solar plants they can result from either component failures or insolation outages. These unscheduled outages are separate from scheduled plant outages for maintenance and seasonal deratings. A margin analysis methodology was developed under the previous study contract (Reference 1). This methodology has been extended under the present study.

When solar power plants are substituted for conventional plants into a total utility grid, a margin analysis must be performed to ensure that the new system including the solar power plants provides service equally reliable as the conventional system. If as a result of increased outages, a system that includes a solar plant requires backup generating capacity to satisfy this reliability criterion, this backup capacity must be taken into account when making comparative economic evaluations. Consequently, the principal issue is to establish the potential of solar power plants to provide capacity displacement in addition to energy displacement when functioning in realistic operating environments.

Solar plants may incur insolation outages in addition to component outages. These insolation outages occur during nonsunshine hours and periods of cloud cover. The occurrence and time durations of these periods will greatly affect the amount of energy storage or hybrid operations required to minimize outages and conventional back-up needs. Since energy storage or hybrid plants are expensive, an economic tradeoff must be made between the amount of storage with the associated larger collector field and the outage rate with the associated conventional plant back-up capacity required.

3.2 DEFINITION AND APPROACH

Margin is a safety factor that assures that even in the event of unscheduled component failures at one or more plant units the electrical demand can be satisfied with the remaining generating capacity. When solar electrical generating plants are considered as part of the total utility grid, the added possibility of an insolation outage must also be regarded as an unscheduled outage. Therefore, insolation outage considerations must be taken into account in the margin analysis involving solar power plants.

The margin definition is shown graphically in Figure 3-1. Depicted is the annual peak demand for electric power as a function of years. The generating capacity required by the utility company to reliably meet this demand 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.

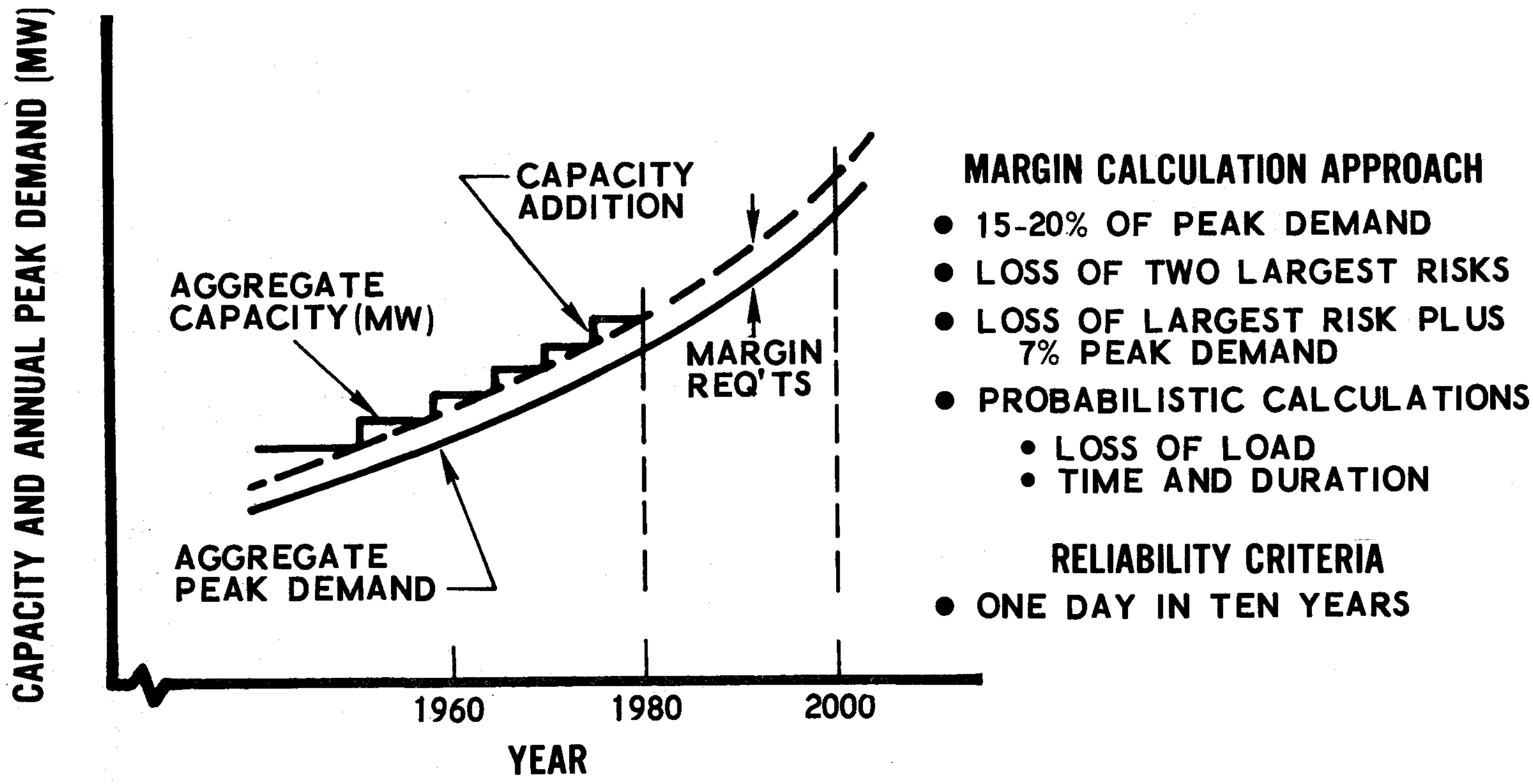


Figure 3-1. Margin Analysis - Definition and Approach

There are various approaches to calculating the margin requirements. The simplest approach is to project generating capacity to exceed peak demand by 15 to 20 percent. With the addition of very large power plants, some utilities equated the margin to the loss of the two largest units in the system or, alternatively, to the loss of the largest unit 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. A typical utility criterion is a loss of load less than or equal to one day in 10 years. For purposes of this study, the probabilistic approach was adopted.

3.3 MARGIN ANALYSIS METHODOLOGY

The basic methodology used in the margin analysis is depicted in Figure 3-2. The analysis is probabilistic in nature, defining a loss-of-load probability on an hourly basis.

The necessary inputs required for computing the loss of load probability are the available electrical generating capacity and the variability and magnitude of the electric load.

The generation capacity model incorporates the various power plant units within a power grid as a function of their individual capacities and outage rates. The forced-outage rates for conventional power plants are a function of type, size, and maturity of power plants. Solar power plants in addition to component failure outages, may experience insolation outages, such as due to cloud cover or darkness without the availability of stored energy. The effective insolation outage rate is a function of the amount of energy storage provided

- ELECTRIC GENERATION CAPACITY
  - ALGORITHM USED TO DERIVE AVAILABLE CAPACITY PROBABILITY DISTRIBUTION ON MONTHLY BASIS

- ELECTRICAL POWER DEMAND
  - METHOD I - DETERMINISTIC HOURLY DEMAND DATA
  - METHOD II - PROBABILISTIC DEMAND DISTRIBUTION FOR EACH HOUR OF DAY FOR EACH MONTH (288 separate probability distributions)

- MARGIN ANALYSIS
  - COMPUTATION OF LOSS OF LOAD PROBABILITY ON HOURLY BASIS
- RELIABILITY CRITERION
  - LOSS OF LOAD NOT TO EXCEED 1 DAY/10 YEARS (~2.4 hrs/yr)

Figure 3-2. Margin Analysis Methodology

and must be determined from hourly systems simulation over an entire year.

Probability distributions describing the total utility system available generating capacity were derived on a monthly basis and for several different mixes of solar and conventional power plants. Component failure outages were treated as statistically independent between various power plants, while insolation outages were conservatively assumed to be statistically dependent between solar plants.

The load or demand model used in the margin analyses is a statistical description of the electric demand for a full year. Two separate methods of modeling the electric power demand were implemented. Method I utilizes deterministic hourly forecasted demand data for an entire year. Method II summarizes the demand data in terms of 24 separate hourly load probability distributions for each of the 12 months of the year. Method II tends to be more conservative than Method I because it takes into account the non-zero probability of exceeding the maximum forecasted load. Method I, however, requires less computer time than Method II, and is therefore preferred from a computer cost standpoint.

By combining the probability distribution describing the utility system total available generating capacity with the distribution defining the projected electrical load, a probability can be developed for the load not to exceed the available capacity ("loss-of-load" condition). By varying the number of plants assumed in the grid the total generation capacity required to satisfy a given criterion, such as loss-of-load not to exceed one day in ten years, can be established.

The system loss-of-load calculations are performed on an hourly basis, and are summed over an entire year of operation. The load and capacity models, as well as loss of load computations, are discussed in detail in the subsequent sections.

3.4 LOAD MODEL

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

The nature of the electrical load or demand is a significant factor in predicting the loss-of-load. A highly variable load will result in a higher probability of loss-of-load or requires increased margins to maintain the same system reliability. The actual load data used in the margin analysis are estimates of hourly demand data forecasted for the year 1990. The demand decomposition/recomposition methodology used to forecast the demand data from historical hourly Southern California Edison Company data is described in detail in Volume II.

Two alternative methods have been implemented by using this demand data for load modeling. Method I uses the hour-by-hour forecasted demand date in a deterministic manner. The demand is compared with the probable available generation capacity at each hour in order to determine the probability of loss-of-load. The predicted loss-of-load for an entire year is then the summation of these hourly loss-of-load probabilities over the entire year. The disadvantage of Method I lies in the fact that the predicted load is treated in a deterministic rather than probabilistic fashion. In spite of the fact that the sample size for a year is very large, this may still not be sufficiently representative for predictive purposes.

Method II attempts to at least partially alleviate this problem by summarizing the demand data in terms of hourly load probability distributions for each month. These data are assumed to be Gaussian to obtain an estimate of the mean and standard deviation. Generally all data less than the largest weekend loads are eliminated, leaving a typical sample size of 22 days out of a total monthly population of 31 days (considering 8 weekend days out of a 31 day month).

The reasons for eliminating weekend loads is that the loads for weekends tend to be lower than for the other days of the week. If the weekend data is not clearly distinguishable, all the days of the month are used in the sample. The data indicates that high usage hours, such as 3 p.m. or 7 p.m., tend to have clearly defined weekend loads, while for 1:00 a.m. weekend loads are usually undistinguishable. Examples of 1:00 a.m. and 3:00 p.m. data for August 1990 are shown in Figures 3-3 and 3-4, respectively.

It should be noted that summarizing data for Method II as described above does not adjust for biases in the data. It relies on the validity of the

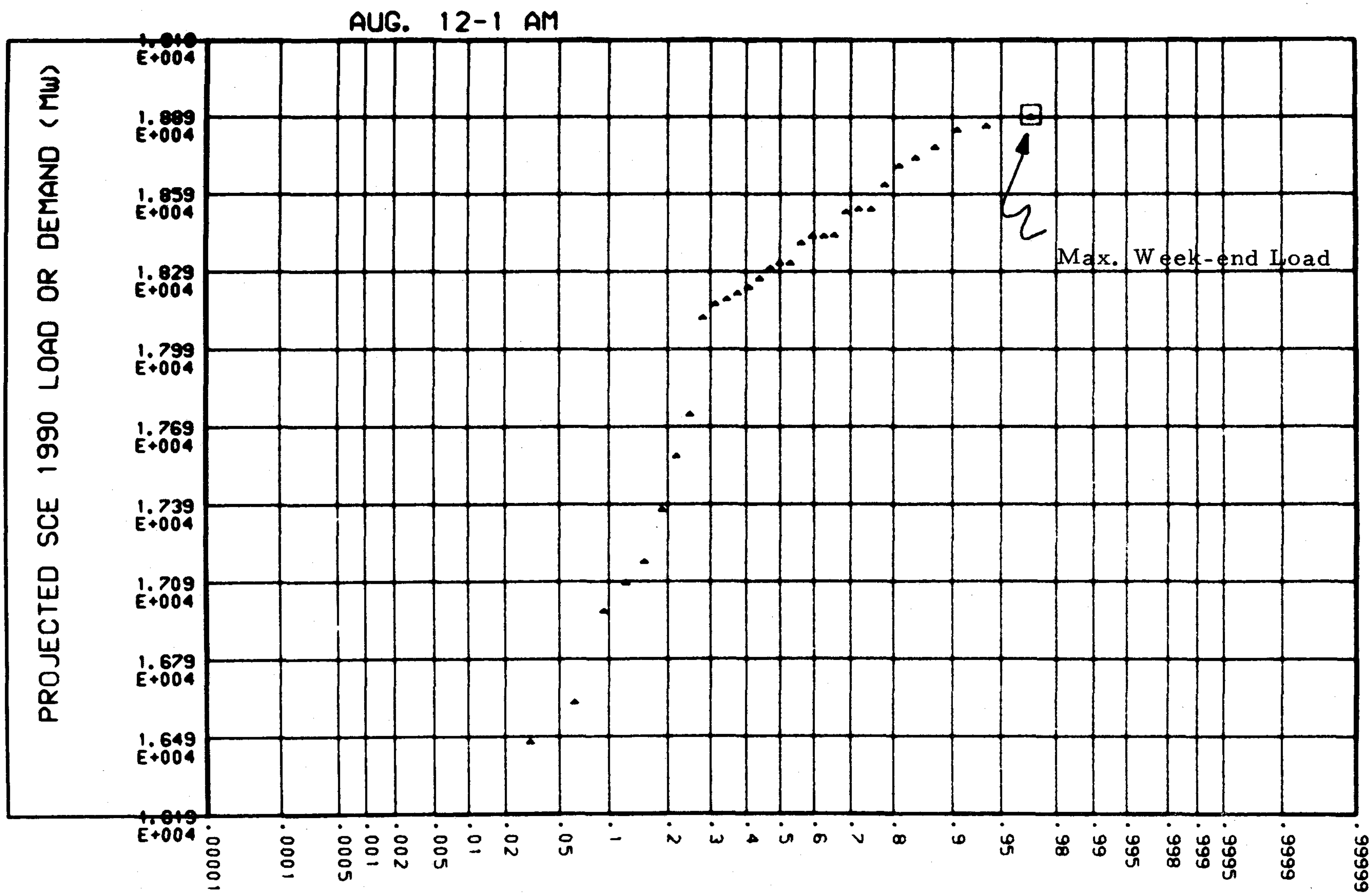


Figure 3-3. Example of Monthly Load Data

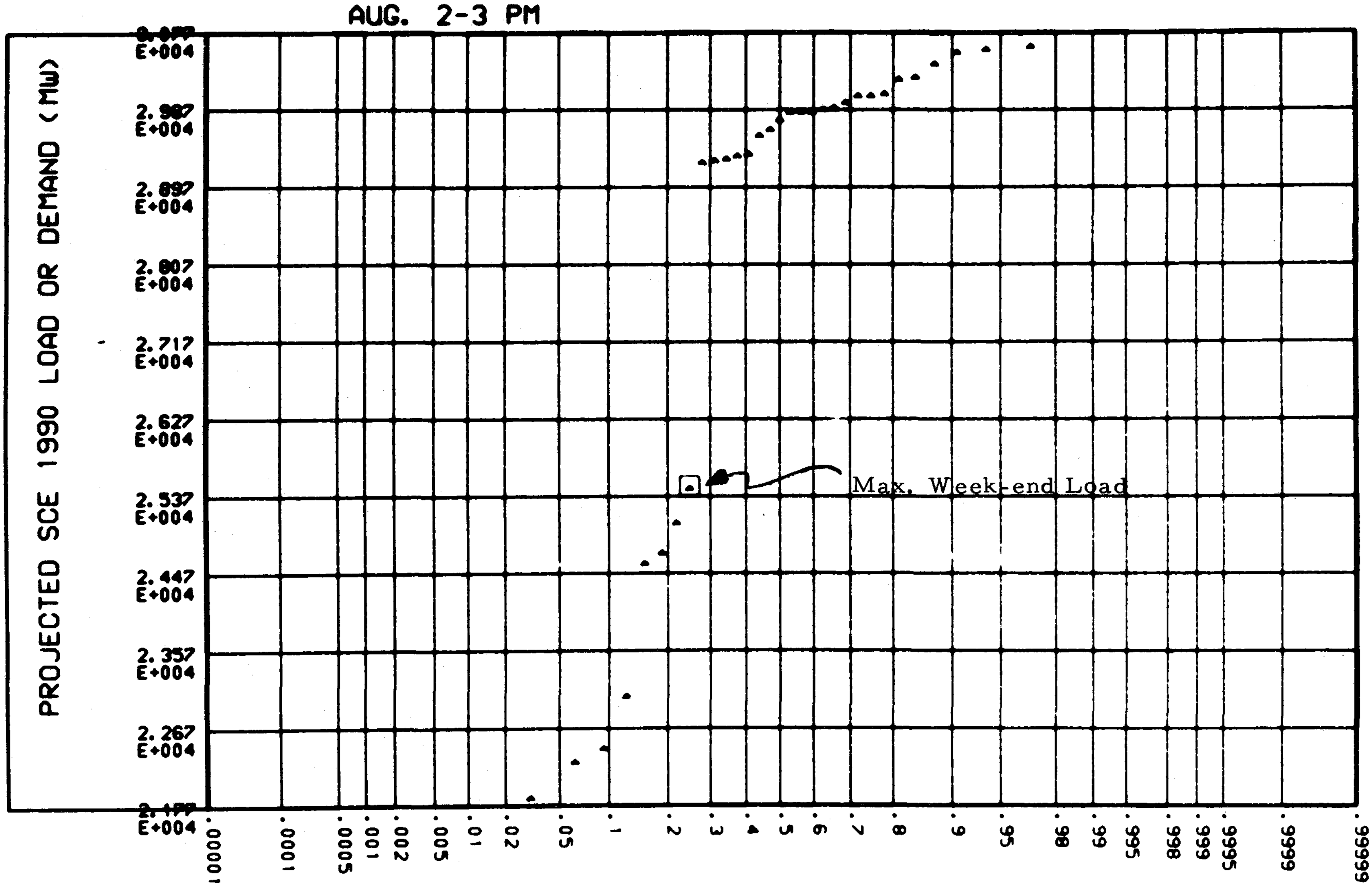


Figure 3-4. Example of Monthly Load Data

forecasted 1990 data. The data was summarized by month for each hour of the day because of the large variation of demand within the day and the more slowly varying nature of demand throughout the year.

3.5 CAPACITY MODEL

In utility system reliability calculations the capacity model normally considers all possible combinations of generating capacity reflecting the various plants comprising the total system. The generation capacity associated with a specific configuration of power plants is primarily a function of the ability of each plant to reliably generate a given power trend. Quantitatively the i^{th} power plant has associated with it the probability p_{ij} of producing the power output x_{ij}. The index $j = 1, 2, \ldots m_i$ is the index over the possible discrete values of power output for the i^{th} plant. Frequently only two possible values for x_{ij} are assumed, namely that the i^{th} plant is "up" with x_{ij} equal to the maximum capacity output or "down" with zero output. In this case $m_i = 2$.

The index i above refers to the i^{th} plant of the total number of plants (n) associated with the utility system. With a realistic number of plants comprising an utility system, the number of possible states of system generation capacity is tremendously large, posing a significant computational problem. This computational problem and an appropriate algorithm to perform the computations without significant degradation in accuracy are described in Appendix B.

The probability distribution obtained from the algorithm described in Appendix B is a distribution function defined at midpoints of intervals of total generation capacity of size Δx. This interval includes values of zero capacity and capacity Δx. The subsequent intervals are evaluated at the midpoints $(k - \frac{1}{2})\Delta x$ for k = 2, 3. . . n and is inclusive of the capacity value $k\Delta x$ at the upper end of k^{th} interval but not of the lower value $(k-1)\Delta x$. The point distribution function of capacity for the configuration will be denoted by:

$$f(x_k), \quad x_k = (k - \frac{1}{2})\Delta x \qquad (3\text{-}1)$$
$$k = 1, 2, \ldots n$$

The cumulative distribution function of capacity is then given by:

$$F(x_\ell) = P_r \{x \le x_\ell\} \qquad (3\text{-}2)$$
$$= \sum_{k=1}^{\ell} f(x_k),$$
$$x_\ell = \ell \Delta x$$
$$\ell = 1, 2, \ldots n$$

The point distribution function $f(x_k)$ is used in the outage computation of Method II and the cumulative distribution function $F(x_\ell)$ is used in the outage computation of Method I described earlier.

The accuracy of the capacity model is a function of the class interval Δx. Figure 3-5 shows partial cumulative distribution functions $F(x_\ell)$ for several values of Δx for a postulated baseline system (a reference generation model containing no solar plants). This variability in accuracy is reflected in the computation of loss-of-load as shown in Figure 3-6, using Method I for load modelling. The outage computation methods are described in the next section.

The interval selected for the comparative evaluation computations was $\Delta x = 10$ MW. This choice was made because the outage computation

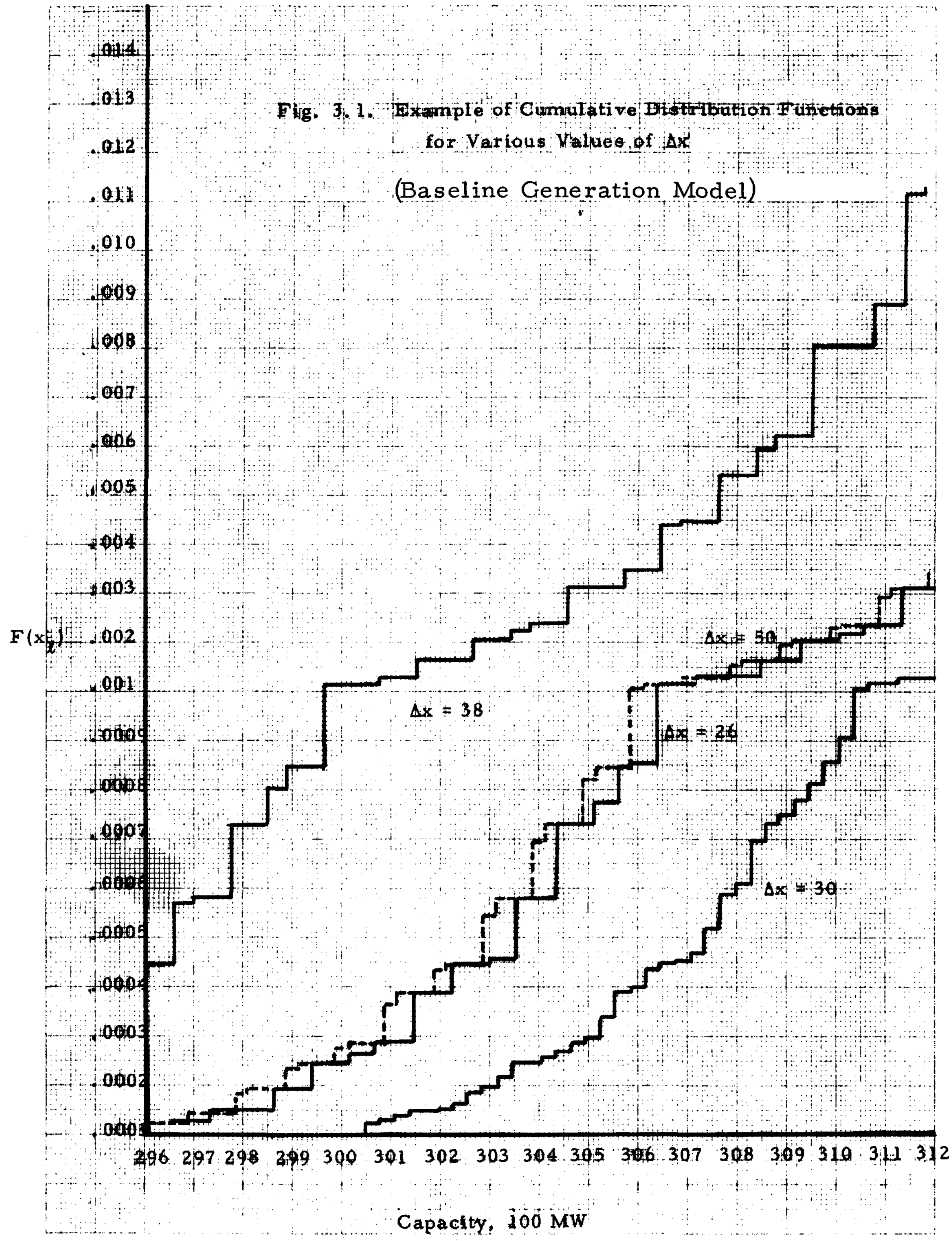


Figure 3-5. Example of Cumulative Distribution Functions for Various Values of Δx

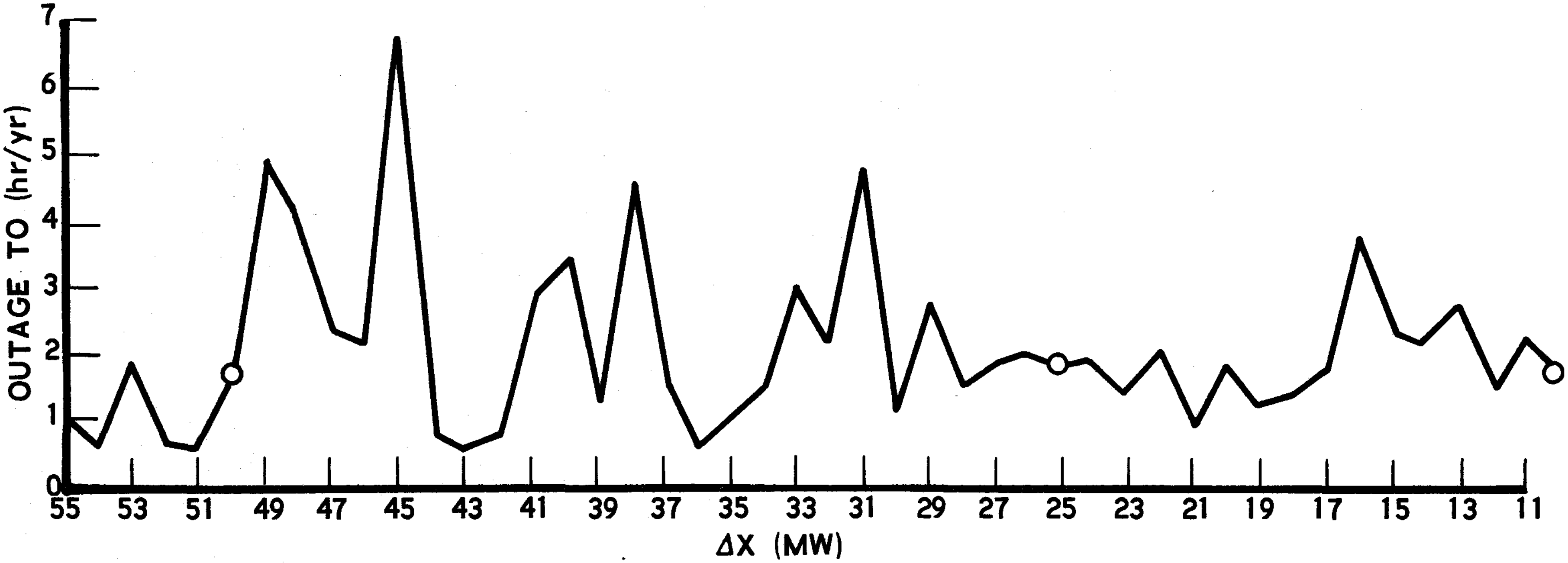


Figure 3-6. Loss-of-Load Function of Capacity Class Interval Δx (Baseline Generation Model)

seems to have stabilized at around this value and because it is desired to limit the computer storage requirements of the computer program. Computational checks show that this value of Δx is adequate for purposes of defining alternative generation models which would provide equal service reliability. A reference Baseline Model which does not include solar plants was identified using this value of Δx for comparison with generation models which include substitutions of solar plants for conventional plants.

3.6 LOSS-OF-LOAD COMPUTATION

As previously discussed, the loss-of-load frequency is determined in a probabilistic manner by comparing the load model with the capacity model on an hour-by-hour basis. If the load for the utility region at any time exceeds the generating capacity at that time, a loss-of-load occurs. In a given time interval the frequency of occurrence of outage events as well as the duration of each outage event enters into the assessment of loss-of-load. Thus a 24-hour loss-of-load outage in 10 years may result from 24 one-hour outages or from one 24-hour outage. The nature of loss-of-load depends on numerous factors such as the amount of power utilized by the region due to a short term hot spell when the air conditioners have excessive use or when almost all TV sets of the community are tuned in simultaneously to an extremely urgent or interesting event. Outages can also occur due to inadvertent random component failures. On a longer term basis loss-of-load can occur because of inadequate grid sizing or due to fuel shortages.

Two methods of computing loss-of-load are described. Both methods assume the probabilistic characterization of capacity (capacity model) as described in Section 3.5 and Appendix B. The alternative to the probabilistic characterization of generating capacity would be deterministic, however, since the plant outages are probabilistic in nature the failures are deterministic only in the sense of a specific Monte Carlo trial.

The two methods of computing loss-of-load differ in the modelling of load or demand. Method I, the Load Data Method, utilizes directly the 8760 hourly load data, y_ℓ (ℓ= 1,2, ... 8760). The loss-of-load is then simply:

$$T_0 = \sum_{\ell=1}^{8760} F(y_\ell)\Delta t \qquad (3\text{-}3)$$

where:

$$F(y_\ell) = \text{capacity cumulative distribution function}$$
$$= P_r\{y \leq y_\ell\}$$
$$y_\ell = \text{hourly load data over the year}$$
$$\Delta t = 1 \text{ hour}$$

The sum in Equation (3-3) can actually be detailed by hours of the day summed over the days of the month and then by summing the months of the year. The loss-of-load can then be displayed as a 12 x 24 matrix array (months x hour) showing the outage time contributed for each hour of the day and each month. The 10-year outage is actually the sum of 10 years of data. In a simplistic sense, assuming no change over the 10 years, the 10-year outage is 10 times the one-year outage. The results in this report are based on a single year of load and insolation data.

Method II, the Load Distribution Method, utilizes a statistical summary of the load data. Thus, each element of the 12 x 24 array mentioned above has associated with it a load probability density g (y) and the probability that the load (y) exceeds the capacity (x) is denoted by:

$$R(x) = \int_x^\infty g(y)\,dy \qquad (3\text{-}4)$$

A more detailed description of the elements of Method II is given in Appendix C.

In practice the load data for a specific hour of a month may be composed of a mixture of two Gaussian populations (essentially weekdays and weekends). An example of this phenomena is shown in Figure 3-4 for 31 days of 3 p.m. data in August 1990. For this case the mixture is composed of a Gaussian population $R_1(x)$ with proportion $p_1 = 22/31$ and population $R_2(x)$ with proportion $p_2 = 9/31$. For this element of the 12 x 24 array the outage is given by:

$$T_{0k} = m_k \Delta t \left[p_1 \sum_{\ell=1}^{n_1} R_1 (x_\ell) f(x_\ell) + p_2 \sum_{\ell=1}^{n_2} R_2 (x_\ell) f(x_\ell) \right] \quad (3\text{-}5)$$

m_k = Number of days in month (= 31 for August 1990)

Δt = Data resolution interval (= 1 hour)

n_1, n_2 = Number of points in summation to point where R_1 and R_2, respectively, are less than or equal to .000004

R_1, R_2 = Gaussian integrals corresponding to g_1 and g_2

p_1, p_2 = Sample proportions (of m_k) in Gaussian mixture (= 22/31 and 9/31, respectively for 3 p.m. data, August 1990)

In the computer program only the first term in Equation (3-5) is considered appropriate because it is felt that the upper tail of g_2 is truncated resulting in a negligible contribution of outage due to g_2. At the current time this is an expediency but will be modified if proven non-valid.

The current criteria used for defining the mixture is to consider all week-end data or loads less than or equal to the largest week-end data as being in the second population, g_2. However, when the second sample consists of less than 15 points a single population is assumed.

It is realized that a careful scrutiny of the nature of the load data is necessary in performing margin analyses because extreme values or values contradicting the assumed Gaussian shapes can invalidate an analysis. An automatic plot routine which displays points as shown in Figures 3-3 and 3-4 has been developed to facilitate this scrutiny.

The loss-of-load computation for the year is then the sum of the outages over all elements of the 12 x 24 array:

$$T_0 = \sum_{k=1}^{288} T_{0_k} \qquad (3\text{-}6)$$

T_{0_k} = outage for specific hour of a month

The two alternative methods for computing loss of load, Method I and Method II, are graphically illustrated in Figure 3-7. Method I shows hourly demand for two days in December compared with the corresponding capacity model. Method II portrays a demand probability density function for 3 p.m. in December related to the corresponding capacity point distribution model.

Typical loss of load computational results for Methods I and II are shown in Tables 3-1 and 3-2. The results portray the individual hourly and monthly loss-of-load probabilities in terms of fractions of an hour loss-of-load. In Table 3-1, for example, a loss probability of .05 occurs at 14:00 hours in July. This corresponds to a .05 hour loss-of-load for that hour. The loss-of-load for an entire year is seen to be 1.78 hours

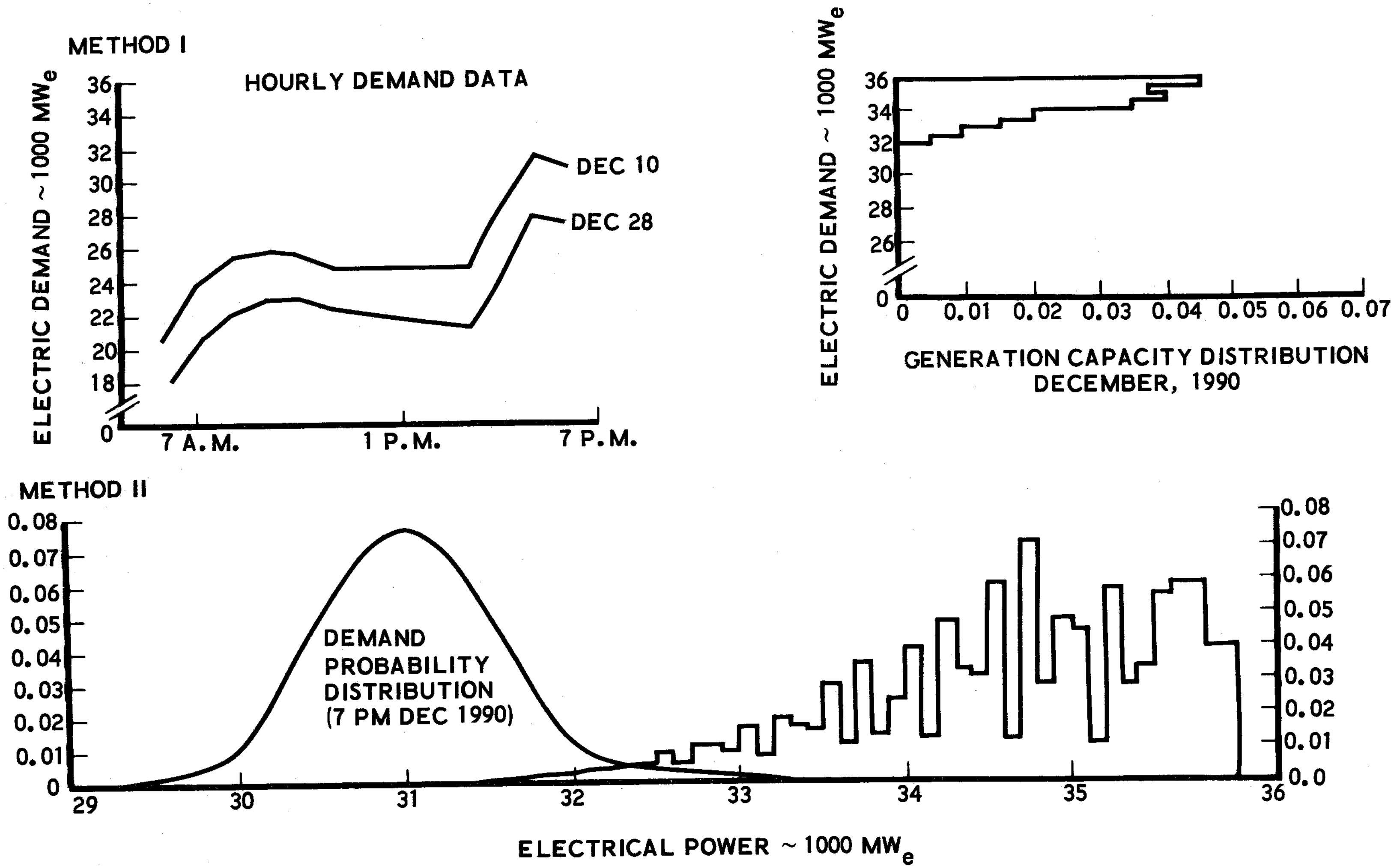


Figure 3-7. Graphical View of Method I and Method II For Computing Loss-of-Load

for Method I, while the more conservative Method II indicates 2.38 hours loss-of-load for the same year (see Section 3.7).

The blocked-out areas in Tables 3-1 and 3-2 show the times of the day for the various months where loss-of-load is predominant. The summer months tend to have losses during the mid-day and afternoon hours, whereas the winter months tend to have losses during the early evening hours. This phenomena can possibly be used in establishing utility operating tactics that would minimize these loss-of-load probabilities and thereby reduce the total required on-line capacity. Thus, the margin analysis can contribute as an operations planning tool, as well as an aid in defining further generating capacity requirements.

3.7 CONVENTIONAL PLANT BASE SEARCH OPTION

Prior to the assessment of solar power plant capacity displacement, a conventional plant baseline generation model was determined. The total conventional baseline generation capacity required to meet a projected Southern California Edison Company (SCE) demand for the year 1990 is shown by the top line in Figure 3-8. As can be seen from this figure, the total installed generation capacity required is 37,000 MWe, consisting of 83 separate power plants, to meet the load shown by the bottom line. This generation capacity was determined to be adequate to permit a 10 percent (5-week) scheduled maintenance period for all power plants and the remaining on-line generation to satisfy the reliability criterion that the loss-of-load not exceed 1 day in 10 years. The scheduled maintenance provision, represented by the crosshatched area of the figure, falls primarily during periods of relatively low demand. The margin requirement for the conventional baseline system, as determined by computer summation assuming a uniform 4 percent unscheduled component outage rate at each plant, is 15.6 percent. The identical on-line

Table 3-1. Loss-of-Load Matrix for Baseline Grid, Method I

********************OUTAGE SUMMARY********************

METHOD I

UNITS ARE IN HOURS

HOUR OF DAY

MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TOTAL
1	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.10	.03	.00	.00	.00	.00	.00	.13
2	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.05	.06	.01	.00	.00	.00	.00	.13
3	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.10	.02	.00	.00	.00	.00	.13
4	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.07	.03	.00	.00	.00	.00	.10
5	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.01	.01	.02	.03	.02	.01	.00	.00	.00	.06	.04	.00	.00	.00	.21
6	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.01	.03	.05	.04	.02	.00	.00	.00	.00	.01	.00	.00	.00	.18
7	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.02	.05	.04	.02	.00	.00	.00	.00	.00	.00	.00	.00	.15
8	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.04	.08	.08	.02	.01	.00	.00	.01	.00	.00	.00	.00	.25
9	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.02	.03	.01	.00	.00	.02	.07	.00	.00	.00	.00	.16
10	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.09	.02	.00	.00	.00	.00	.13
11	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.08	.02	.00	.00	.00	.00	.00	.10
12	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.08	.03	.00	.00	.00	.00	.00	.11

MONTH	Y-MAX	MARGIN
1	28659.	.14449213E+02
2	28120.	.14509246E+02
3	28073.	.14700953E+02
4	27933.	.14539337E+02
5	26677.	.15455261E+02
6	28072.	.14705044E+02
7	30481.	.13513336E+02
8	30692.	.13334595E+02
9	29526.	.13799009E+02
10	29177.	.1[illegible]38258E+02
11	29858.	.13872329E+02
12	32000.	.12500000E+02

ONE YEAR OUTAGE = .17804197E+01 HOURS

Table 3-2. Loss-of-Load Matrix for Baseline Grid, Method II

Δx = 50

*********************OUTAGE SUMMARY*********************
METHOD 2

UNITS ARE IN HOURS

HOUR OF DAY

MONTH	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TOTAL
1	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.18	.07	.01	.00	.00	.00	.00	.26
2	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.06	.07	.01	.00	.00	.00	.00	.14
3	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.11	.02	.00	.00	.00	.00	.14
4	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.15	.04	.00	.00	.00	.00	.19
5	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.01	.01	.02	.03	.02	.01	.00	.00	.00	.06	.05	.00	.00	.00	.25
6	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.01	.04	.07	.07	.03	.01	.00	.00	.00	.02	.00	.00	.00	.27
7	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.04	.07	.06	.02	.01	.00	.00	.00	.00	.00	.00	.00	.21
8	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.04	.09	.08	.02	.01	.00	.00	.01	.00	.00	.00	.00	.27
9	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.03	.03	.01	.00	.00	.02	.07	.00	.00	.00	.00	.17
10	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.01	.11	.03	.00	.00	.00	.00	.15
11	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.11	.03	.01	.00	.00	.00	.00	.14
12	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.02	.11	.05	.01	.00	.00	.00	.00	.20

ONE YEAR OUTAGE = .2379.497E+01 HOURS

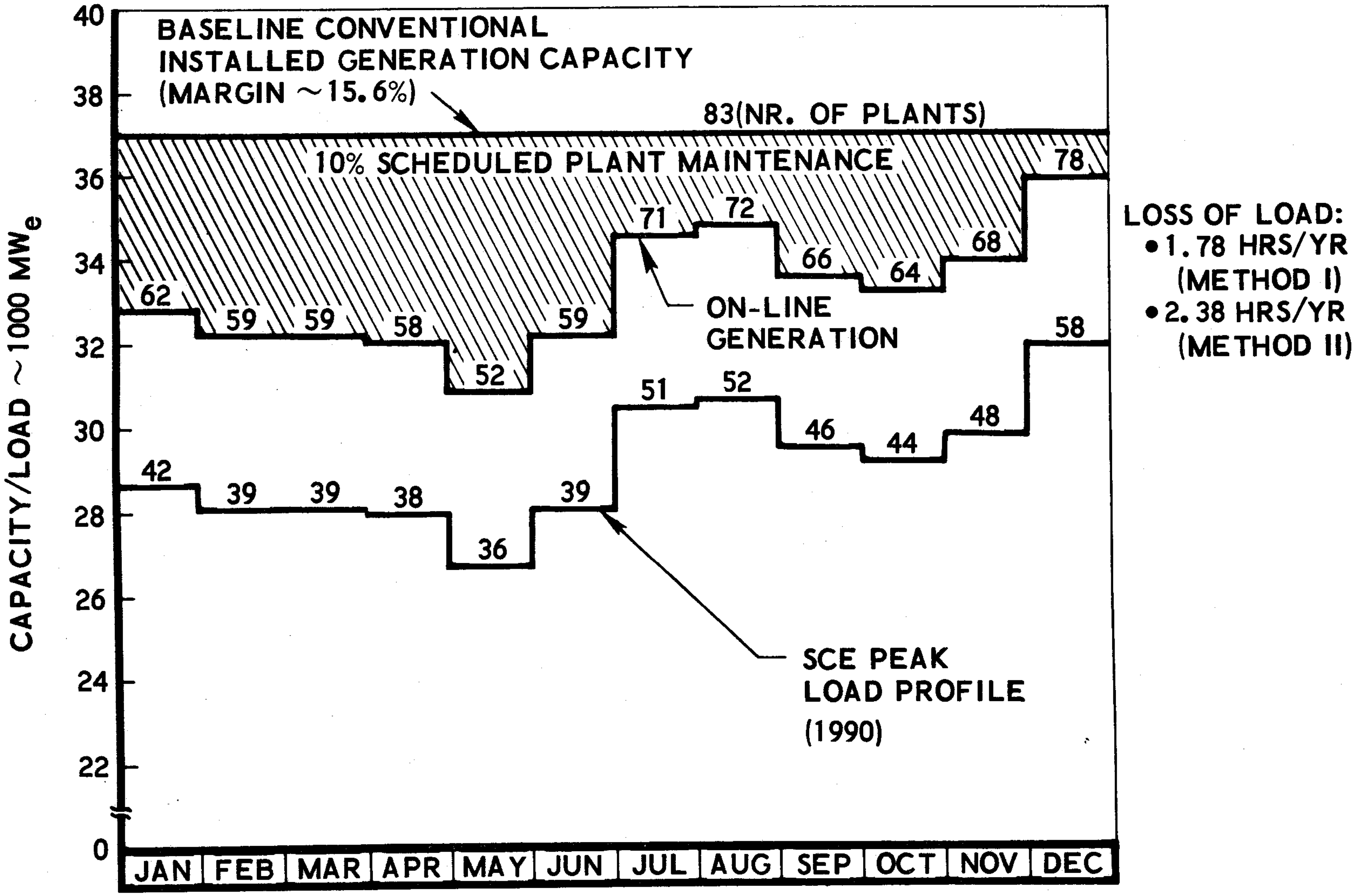


Figure 3-8. Conventional Plant Baseline Generation Capacity

generation capacity profile, shown in Figure 3-9 was obtained by both Methods I and II, although Method II resulted in a slightly greater computed loss-of-load (2.38 hours/year versus 1.78 hours/year).

The Baseline Search Option in the computer program utilizes as input the monthly peak load profile. A typical profile is shown as the bottom curve in Figure 3-8. An apriori ordering or stacking of plants in the configuration is also assumed. A simple example of an ordering is shown in Figure 3-9.

The search option starts with the peak monthly load profile. A minimum capacity profile sized to meet or just exceed this profile is established next. As an example, the peak loads for May and December are 26,677 MW and 32,000 MW for these two months. Based on a capacity profile derived in this manner for all months, the loss-of-load can be computed by using either Method I or II load models, as described in Section 3.4. If the loss-of-load exceeds 2.4 hours in one year, the baseline search option procedure increments the monthly capacity profile by the rated capacity corresponding to the next plant in the stacking order (see Figure 3-9). Based on this new capacity profile, the loss-of-load is again computed and compared with the reliability criterion. This process is continued until the computed loss-of-load is equal to or less than the recommended reliability criterion of 2.4 hours in one year. The resultant capacity profile is represented in Figure 3-8 as the required on-line generation capability.

As indicated in Figure 3-8, there is a significant increase in the number of plants from the minimum capacity profile, represented by the monthly peak load, to the required on-line generation capacity profile. This is a consequence of the assumed 4 percent unscheduled component outage rate and the restrictive reliability criterion.

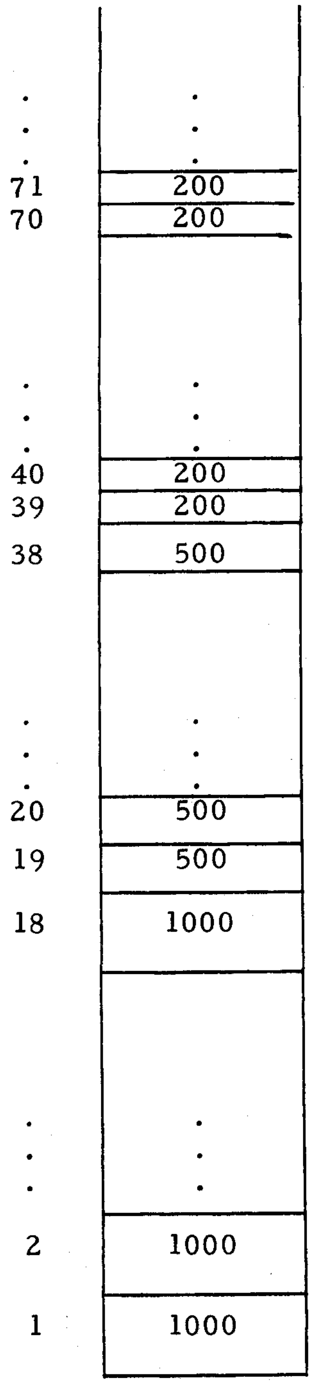


Figure 3-9. Plant Stacking Order in Generation Grid Network

As stated previously, the identical on-line generation capacity profile, shown in Figure 3-8, was obtained by both Methods I and II, although Method II resulted in a slightly greater computed loss-of-load (2.38 hours per year versus 1.78 hours per year). The use of hour-by-hour load data (Method I) would approach the load distribution method (Method II) as the data sample size (number of hours) gets arbitrarily large, provided the distribution (Gaussian in this case) assumed for Method II is valid. While continuing checks need to be made as to the validity of Method I in accounting for random occurrences of large loads, it is gratifying that the two methods obtain the same result, particularly in view of the fact that Method I takes about 1/16th the computer time of Method II. As a consequence of the reduced computer time required for Method I and the close approximation of results with Method II, Method I was used in subsequent margin analyses as described in Section 3.8.

The margin percentages for the conventional baseline generation model are shown in Table 3-3. The margin is expressed as the excess generation capacity over peak demand for the particular period under consideration:

$$M = \left(\frac{x_r - y_{max}}{y_{max}} \right) \times 100 \text{ (percent)} \qquad (3\text{-}7)$$

x_r = Rated capacity of the generation model for the month under consideration

y_{max} = Peak load or demand for the month under consideration

The margin has been evaluated for both the capacity profile (on-line generation) and the installed generation capacity in this table.

The monthly loss-of-load results for both Methods I and II are also presented in Table 3-3. The month-to-month variability in the loss-of-load results is not considered unduly large or indicative of the need for reshaping the monthly capacity profile. This variation is mainly due to the resolution differences between the monthly capacity profile and the corresponding load profile arising from incremental rather than continuous power plant sizes.

The Baseline Generation Model capacity profile has essentially the same shape as the load profile as shown in Figure 3-8. If the total installed generation is assumed to be constant during the year, a provision for scheduled maintenance can be defined (shaded in Figure 3-8) by a simple integration and differencing routine. In order to provide a 10 percent scheduled maintenance period for each unit and also meet the loss-of-load criterion, the total generation model must be composed of 83 plants as shown by the constant capacity of 37,000 MW at the top of Figure 3-8.

As can be seen from Table 3-3, the overall yearly margin for the conventional baseline system is 15.6%.

3.8 BACK-UP CAPACITY SEARCH OPTION

The baseline search option described in the previous section can also be used for generation models that include solar as well as conventional plants. The inputs for the solar plants, however, are different than those for conventional plants. In addition to unscheduled component outages solar plants also experience insolation outages. These outages vary hour-by-hour as a function of the incident insolation and the available storage capacity of the solar plants.

TABLE 3-3

Margin for Baseline Conventional

Plant Grid Network

(Margin in Percent)

Month	Margin (%) Capacity Profile	Margin (%) Installed Generation Capacity	Loss-of-Load (hrs) Method I	Loss-of-Load (hrs) Method II
1	14.4	29.1	.13	.26
2	14.5	31.6	.13	.14
3	14.7	31.8	.13	.14
4	14.5	32.4	.10	.19
5	15.5	38.7	.21	.25
6	14.7	31.8	.18	.27
7	13.5	21.4	.15	.21
8	13.4	20.6	.25	.27
9	13.8	25.3	.16	.17
10	13.8	26.8	.13	.15
11	13.9	23.9	.10	.14
12	12.5	15.6	.11	.20
	14.1 AVE	27.4 AVE	1.78	2.38

Just as the statistical load data for Method II can be displayed in a matrix of 12 x 24 (or 288) load distributions, the capacity model for a system including solar plants can also be described by a 12 x 24 matrix of capacity distributions. These hourly distributions for each month can be derived from the solar plant performance simulation results. The computer program modifes (reduces) the rated capacity of the solar plants by the insolation outages and recomputes the capacity model probability distributions. In order to minimize computer time and storage, the computer stores the 12 capacity models associated with the subset of conventional plants and computes the total capacity distributions by incremental addition of the solar plants for each hour of each month. The algorithm to obtain the capacity distributions allows for incremental addition of plants but not for deleting plants.

The program can process solar plant outputs corresponding to two different geographical locales. It is assumed that all solar plants in the same locale behave in the same way in terms of insolation outages. The individual solar plants may, however, have different rated capacities.

A back-up capacity search option is used to determine the incremental back-up conventional plant capacity required when solar plants are substituted for conventional plants in the baseline generation model. The following section describes the use of the back-up capacity search option in determining solar plant capacity displacement.

3.9 SOLAR PLANT CAPACITY DISPLACEMENT

When solar plants are substituted for conventional plants with similar rated capacities some conventional back-up capacity may be required to achieve the same overall system reliability. The ability of solar plants to displace conventional plants is termed capacity displacement. The larger the capacity displacement, the smaller the conventional back-up capacity required.

Starting with the previously described conventional baseline generation model, individual solar plants were substituted for conventional plants in order to determine their capacity displacement potential. Table 3-4 outlines the general approach followed. As shown in Table 3-4, the baseline generation model consists of 83 conventional power plants incorporating baseload, intermediate, and peaking units, to meet projected 1990 demand profile for the Southern California Edison service territory with a peak load of 32,000 MWe.

Intermediate solar plants, varing in size from 100 to 500 MWe, were substituted for conventional plants. The total conventional capacity displaced by the solar plants was parametrically varied between 1000 and 5000 MWe, requiring a different number of solar plants depending on their individual size. Individual plant component outage rates of 4 percent were assumed for solar as well as conventional plants, while solar plant outages were determined by performance simulations.

Subsequently, solar plant capacity displacement were determined using the margin analysis methodology described in Section 3.8. The back-up capacity search option was used to determine the conventional back-up capacity required, or conversely, the effective solar plant capacity displacement. In order to limit the computation time required for the

Table 3-4. Solar Plant Substitution For Conventional Plants

- SCE PEAK DEMAND (1990) - 32,000 MW_e
- GENERATION MODEL - CONVENTIONAL (idealized)

PLANT TYPE	SIZE (MWe)	NR. OF UNITS	CAPACITY (MWe)	PERCENT (%)	COMPONENT OUTAGE (%)
BASE LOAD	1000	18	18,000	49	4
INTERMEDIATE	500	20	10,000	27	4
PEAKING	200	45	9,000	24	4
TOTAL		83	37,000	100	

- SOLAR THERMAL PLANTS (substituted for conventional units)

PLANT TYPE	SIZE (MWe)	NR. OF UNITS	CAPACITY (MWe)	COMPONENT OUTAGE (%)	SOLAR* OUTAGE (%)
INTERMEDIATE ↓	500	2, 4, 6, 8, 10	1000-5000 ↓	4 ↓	0-100
	250	4, 8, 12, 16, 20			
	100	10, 20, 30, 40, 50			

- RELIABILITY CRITERION
  - LOSS OF LOAD ~1 DAY/10 YEARS
- CONVENTIONAL BACK-UP CAPACITY REQUIRED

*Determined from system simulation

large number of combinations of plant substitutions considered, the search option was simplified by using only 12 average monthly solar plant capacity model distributions, rather than the design capability of 288.

Typical results of the margin analysis in terms of the capacity displacement potential of solar plants are presented in Figures 3-10 and 3-11. The solar plant capacity displacement and the associated conventional back-up capacity required are described as a function of solar plant insolation outage.

The amount of conventional back-up capacity required to maintain the system loss-of-load reliability criterion associated with the baseline generation model depends on a number of parameters:

- Order of substitution.
- Total capacity of solar power plant penetration.
- Size of the solar plants replacing the conventional plants.
- Size of the conventional plants substituted.
- The size of the conventional back-up plants.

The specific cases presented in Figures 3-10 and 3-11 consider the substitution of 10 or 30 individual 100 MWe solar plants for an equivalent 1000 MWe or 3000 MWe of conventional plant capacity respectively. Three different conventional plant sizes (each displaced by one or more solar plants) are shown, indicating the sensitivity of solar plant size to the displaced conventional plant size for this penetration.

As indicated on Figures 3-10 and 3-11, small insolation outages of solar plants do not require conventional back-up capacity, and therefore, their capacity displacement is effectively 100 percent. The reason for this is due to the replacement of one large conventional plant with two or more

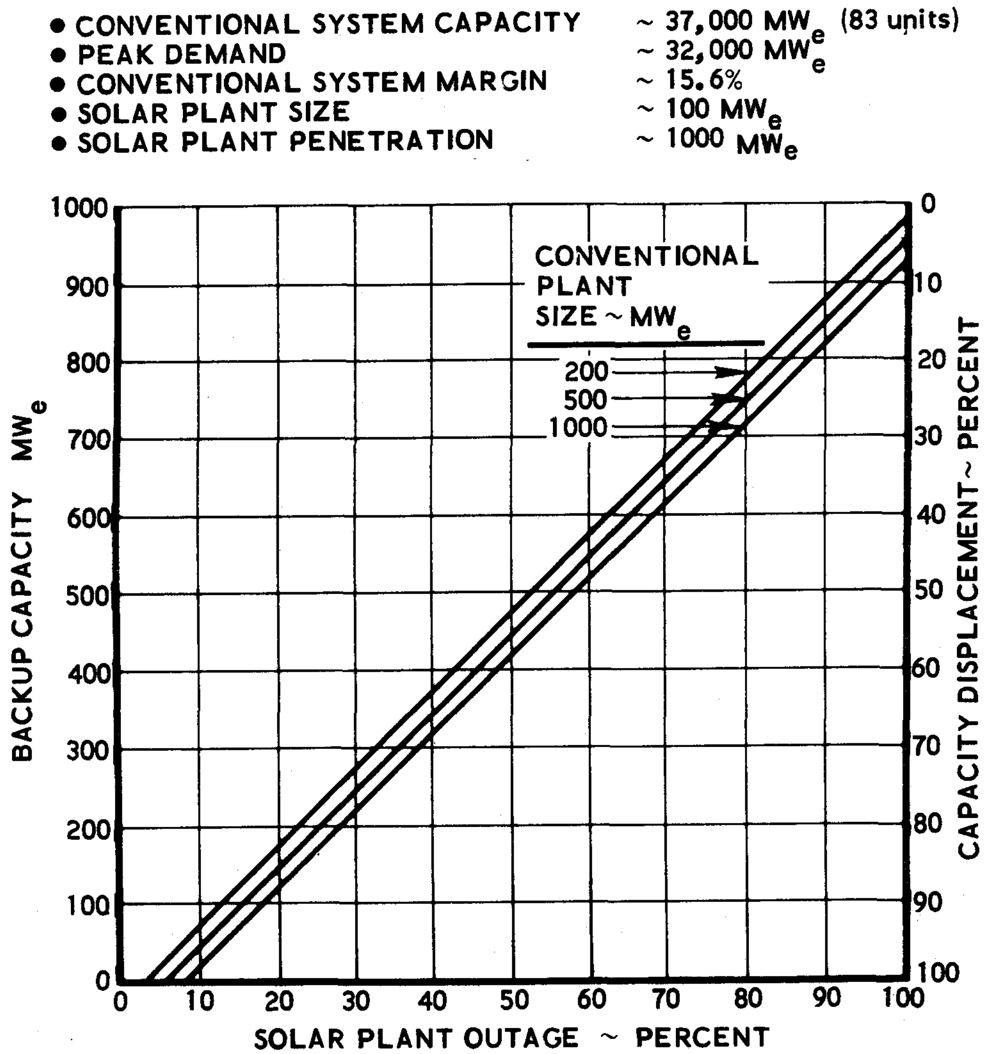


Figure 3-10. Margin Analysis - Capacity Displacement

- CONVENTIONAL SYSTEM CAPACITY ~37,000 MW_e (83 units)
- PEAK DEMAND ~32,000 MW_e
- CONVENTIONAL SYSTEM MARGIN ~15.6%
- SOLAR PLANT SIZE ~100 MW_e
- SOLAR PLANT PENETRATION ~3,000 MW_e

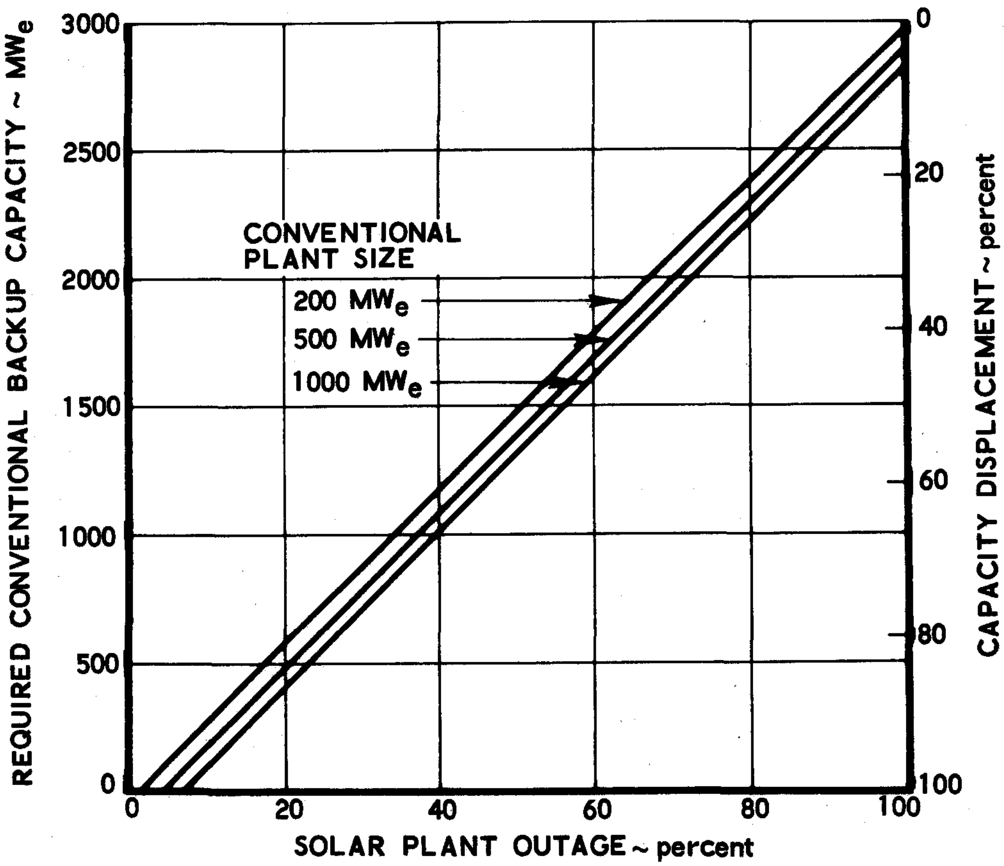


Figure 3-11. Margin Analysis - Capacity Displacement

solar plants, thus spreading the effect of increased (component plus insolation) outages. Also, for theoretical solar plant outages of 100 percent, the required back-up capacity is less than 1000 MW or 3000 MWe. The reason is the use of conventional back-up plants of 100 MWe (in effect large conventional plants are replaced by several smaller ones in this limiting situation).

The capacity displacement of the alternative solar thermal conversion systems and the associated conventional back-up capacity requirements when necessary for equal reliability of operation, have been accounted for in the economic comparisons of the solar plants with conventional power plants.

4. COMPARATIVE ECONOMIC ANALYSIS

The comparative economic evaluation of alternative solar power plants and conventional power plants is discussed in this section.

4.1 ECONOMIC ANALYSIS 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 evaluation.

The principal effort was to develop a methodology for comparative economic analyses of solar thermal power plants and conventional power plants. This methodology is documented in an interim report: "Power Plant Economic Model" (Reference 2).

The Comparative Economic Evaluation depends heavily on the results of the Comparative Technical Evaluation and Margin Analysis which precede this section. For the solar thermal conversion power plants a cost sensitivity analysis was also performed of those items which have either a large impact on the total cost or have a substantial 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 1973 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 (GNP) implicit price deflator, was assumed to average three percent per year from 1973 into the future, even though fluctuations in this rate will occur for certain time periods. While this rate is much less than the

1972-74 rate, it is consistent with the long term (1958 to 1972) annual rate of 2.9 percent (Reference 3, 4). It is recognized that this three-percent inflation 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 ten price indices. These indices and their projected escalation rates are shown in Table 4-1. Since all escalation rates are consistently expressed in terms of the assumed inflation rate, the comparative economic analyses remain valid regardless of the actual rate of inflation.

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) (Reference 5). The investment accounts were selectively subdivided into a Work Breakdown Structure which is shown in Table 4-2. The conventional power plants investment accounts are handled at the summary two-digit level. The investment accounts that have been added to accommodate solar power plants and environmental protection systems have been broken down to the three-digit and four-digit level of detail. Each of these accounts has a composite escalation rate which are based on the proportions of factory equipment and site construction materials and labor. Table 4-3 shows the account numbers, title, basis, and composite escalation rates. Escalation rates for the two other direct investment cost accounts, contingency and spare parts, are determined from the composite escalation rates of the direct cost accounts in Table 4-3. The projected rate of inflation (GNP price deflator) is used as the basis for these escalation values, so that a higher rate of inflation results in higher investment account escalation rates.

TABLE 4-1

Price Indices Escalation Rates

NO.	PRICE INDEX	PROJECTED ANNUAL ESCALATION RATE
1.	Industrial and Commercial Construction Labor and Materials (Boeckh Index of Construction Costs) (Ref. 3, 4)	4.7%
2.	Electrical Machinery and Equipment (Wholesale Price Index) (Ref. 3, 4)	1.0%
3.	All Machinery and Equipment (Wholesale Price Index) (Ref. 3, 4)	1.8%
4.	Iron and Steel Products (Wholesale Price Index) (Ref. 3, 4)	3.6%
5.	Rural Land (Department of Agriculture Index) (Ref. 6)	6.1%
6.	GNP Implicit Price Deflator (Ref. 3, 4)	3.0%
7.	Industrial Chemicals (Wholesale Price Index) (Ref. 3, 4)	0%
8.	Turbine/Generators (Handy-Whitman Index) (Ref. 10)	1.1%
9.	Boilers (Handy-Whitman Index) (Ref. 10)	3.0%
10.	Fuel Handling Equipment (Handy-Whitman Index) (Ref. 9)	1.6%

TABLE 4-2

Power Plant Economic Model

Work Breakdown Structure

Investment Cost

Account No.	Account Title
A12	Boiler Plant Equipment
A20	Land
A21	Structures
A22	Reactor Plant Equipment
A23	Turbine Plant Equipment
A24	Accessory Electric Plant Equipment
A25	Miscellaneous Equipment and Environmental Systems
A26	Special Nuclear Materials
A27	Solar Equipment
A28	Solar Thermal Storage Materials
A29	Special Construction - Structures and Facilities
A30	Miscellaneous Investment (Non-Depreciable)
A90	Indirect Construction Cost
A40	Spare Parts
A41	Contingency Allowance

TABLE 4-2 (continued)

Account	Account Title and Description
A12	Boiler Plant Equipment: This account is used for fossil or hybrid fuel power plants only. The cost components for escalation are: (1) Construction labor and materials, 35% (2) Factory equipment - boilers, 40% (3) Factory equipment - fuel handling equipment, 15% (4) Factory equipment - iron and steel products, 10%
A20	Land - Acquisition Cost: This account includes the cost of relocating utilities and buidlings. For escalation rate use projected escalation rate for land.
A21	Structures: This account includes all structures and facilities required for the conventional portion of power plants. In the case of solar plants, in the absence of specific data, the cost of structures for the heat exchanger is assumed to be equal to the cost of structures for the boiler plant. Not included in this account are the costs for structures required for solar collectors or other special construction facilities. For escalation this account is composed 100% of construction labor and materials.
A22	Reactor Plant Equipment: This account is used only for nuclear power plants. The cost components for escalation are: 50% construction labor and materials, and 50% factory equipment- iron and steel products.
A23	Turbine Plant Equipment: This account is used for all types of power plants. The cost components for escalation are: (1) Construction labor and materials, 24% (2) Factory equipment - turbo-generators, 61% (3) Factory equipment - iron and steel products, 15%

TABLE 4-2 (continued)

Account	Account Title and Description
A24	Accessory Electrical Plant Equipment: The cost components of this account for escalation are: (1) Factory equipment - electrical machinery, 31% (2) Construction labor and materials, 69%.
A25	Miscellaneous Plant Equipment and Environmental Systems
25.1	Transportation Communications and Lifting Equipment, Air and Water Service Systems, Furnishings and Fixtures.
25.2	SO_2 Removal System
25.3	Zero Radwaste System
25.41	Cooling Towers - Natural Draft* - Wet**
25.42	Cooling Towers - Natural Draft* - Dry**
25.43	Cooling Towers - Mechanical Draft - Wet**
25.44	Cooling Towers - Mechanical Draft - Dry**
25.45	Cooling Towers - Mechanical Draft (Plume Abatement) Wet/Dry**
25.46	Cooling Towers - Mechanical Draft (Water Conservation) Wet/Dry**
25.5	NO_x Control System**
25.6	Other Environmental Control Systems**

For the subaccount 25.1 the cost components for escalation are: (1) factory equipment - all machinery and equipment, 70%; and (2) construction labor and materials, 30%. For other subaccounts estimate proportions of (1) factory equipment, and (2) construction labor and materials.

* Includes Basin

** Includes cost of required structures in addition to part included in basic power plant under A21 - Structures.

TABLE 4-2 (continued)

Account	Account Title and Description
A26	Special Nuclear Materials: This account is for a nuclear power plant only. It is used for the cost of reactor coolant in the case of gas-cooled nuclear power plants. For escalation the cost component is 100% industrial chemicals.
A27	Solar Equipment
27.1	Heat Exchanger Equipment
27.2	Central Receiver Equipment*
27.3	Concentrating Collector Equipment
27.4	Flat Plate Collector Equipment
27.5	Heliostat Equipment
27.6	Pumps and Pipes - Thermal Material

For escalation, in the absence of data for specific designs, the following cost components are to be used:

	Factory Equipment All Machinery & Equipment	Construction Labor & Materials	Iron and Steel Products
27.1	90%	10%	
27.2	90%	10%	
27.3	70%	30%	
27.4	60%	30%	10%
27.5	80%	20%	
27.6	10%	10%	80%

*Excludes special structures and facilities (e.g., central towers)

TABLE 4-2 (continued)

Account	Account Title and Description
A28	Thermal Storage Materials
28.1	Sodium
28.2	Hitec
28.3	Other

For escalation the cost component is industrial chemicals, 100%.

Account	Account Title and Description
A29	Special Construction Structures and Facilities
29.1	Reinforced Concrete Tower
29.2	Steel Grid Tower
29.3	Thermal Storage Tanks
29.4	Special structures for solar collectors

For escalation the cost component is construction labor and material, 100%.

Account	Account Title and Description
A30	Miscellaneous Investment: This account is for any investment costs which are judged to be of a non-depreciable nature. The escalation rate is to be based on the proportion of the two cost components. These are: (1) construction labor and materials, and (2) factory equipment - all machinery and equipment. An example of an entry in this account could be the dam used for a pumped storage or hydroelectric power plant.
A90, A40, A41	Indirect Construction Cost, Spare Parts Contingency Allowance: These accounts require no breakdown or data input as they are internally generated by the Power Plant Economic Model.

TABLE 4-3

INVESTMENT ACCOUNT COMPOSITE ESCALATION RATES

	INVESTMENT ACCOUNT	COMPOSITE ESCALATION RATE PER YEAR	PRICE INDEX BASIS
A12	Boiler Plant Equipment	3.4%	1 (35%) 4 (10%) 9 (40%) 10 (15%)
A20	Land	6.1%	5
A21	Structures	4.7%	1
A22	Reactor Plant Equipment	4.2%	1 (50%) 4 (50%)
A23	Turbine Plant Equipment	2.3%	1 (24%) 4 (15%) 8 (61%)
A24	Electric Plant Equipment	3.6%	1 (69%) 2 (31%)
A25	Miscellaenous Plant Equipment and Environmental Systems	Varies*	
A26	Special Nuclear Materials	0%	7
A27	Solar Equipment	Varies*	
A28	Solar Thermal Storage Materials	0%	7
A29	Special Depreciable Construction Cost	4.7%	1
A30	Miscellaenous (Non-depreciable)	Varies**	
A90	Indirect Construction Cost	4.7%	1
A40	Spare Parts	2.0%	2 (40%) 3 (30%) 4 (30%)

* Varies with the mix of subaccount components.

** Varies with nature of content of account.

Escalation rates for other cost categories are shown in Table 4-4. The zero percent escalation rate for insurance and property tax is due to the use of lifetime levelized rates which are applied to the initial undepreciated value of the total plant investment. Projected escalation rates for fuels were also determined. The effects of resource depletion on future nuclear fuel cycle and fossil fuel costs were investigated and these effects are reflected in the projected fuel escalation rates. These escalation rates are included in the section on fuel prices.

The cost-of-capital (after taxes) is also related to the assumed rate of inflation. The cost of capital rate used 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 (References 7, 8). 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 desirable 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 4-5. Details concerning the cost-of-capital are discussed in Reference 2.

4.3 POWER PLANT ECONOMIC ANALYSES

Several methods exist for the economic assessment of power plants. The discounted cash flow (DCF) analysis is the most sophisticated method used in financial investment analyses. This method has the greatest flexibility, but is also the most complex, often requiring the use of a digital computer. The output of this method can either be in constant or current dollars.

TABLE 4-4

OTHER ESCALATION RATES

COST CATEGORY	ESCALATION RATE/YEAR
Operation and Maintenance	4.0%
Transmission Cost	3.0%
Distribution Cost	4.0%
Revenue/Kwh	2.0%
Insurance/Property Tax	0%

TABLE 4-5

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 7, 8.

Alternatively, the utility industry frequently uses the levelized fixed charge method, which on the surface is relatively simple to use, but is less flexible. This method is derived from the discounted cash flow analysis and utilizes a pre-determined (from DCF analysis) levelized fixed charge rate to compute the fixed charges. To be consistent, levelized variable costs should also be input to this method, which results in a levelized value of the busbar energy cost output.

Both of these methods are discussed in some detail in this section.

4.3.1 Discounted Cash Flow (DCF) Economic Analysis 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 systems can be determined by economic evaluation of these and conventional nuclear and fossil power plants for identical periods of commercial operation.

During this contract the DCF economic analysis methodology was completed as an operational computer program. This program was documented in an interim report, "Power Plant Economic Model: Program Description/User's Guide", published separately in June 1974 (Reference 2). The Power Plant Economic Model report provides a detailed description of the model (a summary description is included in Appendix D).

The flow chart of the economic methodology is shown in Figure 4-1. The intial input data are the capital investment costs of each subsystem account which are estimated for a given size power plant in terms of base year (e.g., 1973) dollars. To determine the relative economics of different size power plants, an economies-of-scale routine has been included, consisting of cost scaling relationships. This subroutine is separately applied to individual subsystem investment accounts permitting

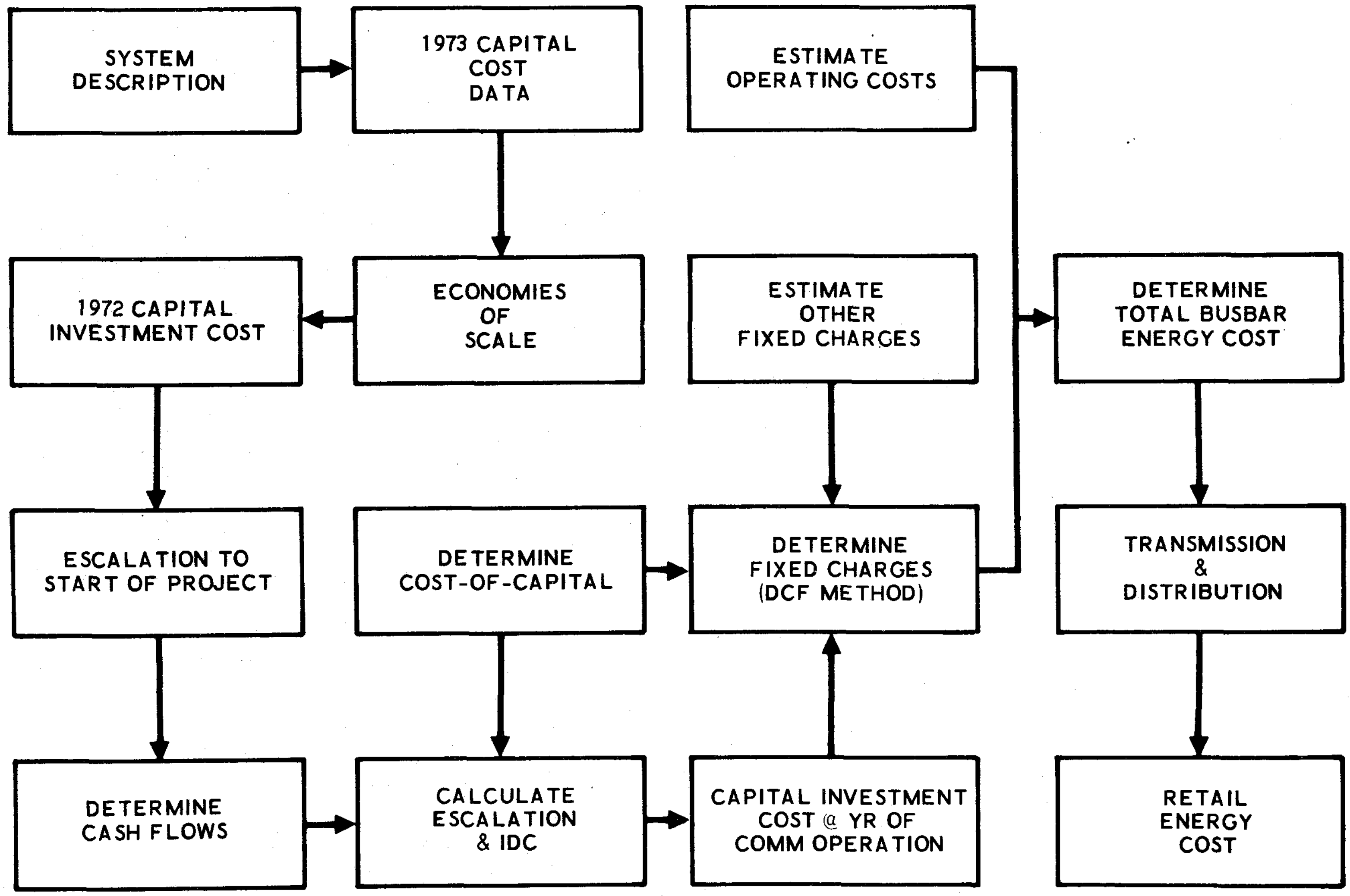


Figure 4-1. Economic Analysis Methodology

greater accuracy in estimating capital costs. 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 from the base year to 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 this construction time period.

The base year capital investment cost combined with 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.

Cash flows derived from pro forma income statements are discounted to the year of commercial operation. The rate of discount is the cost of capital typical of the utility industry. This rate is estimated by the weighted average after-tax cost of common and preferred equity and long-term debt. The discount rate is used to calculate the present value of the cash flows during the operating life of the plant. Estimated operating costs are combined with fixed charges to determine total busbar energy costs.

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

A special option of the model permits the calculation of a power plant's levelized fixed charge rate. Total fixed charges are computed for each year of a plant's operation. The fixed charges for each year are discounted to the year of commercial operation and the levelized fixed charges are computed. The levelized fixed charges are divided by the capital investment at the year of commercial operation to compute the levelized fixed charge rate for use in the levelized fixed charge rate m method of economic analysis.

A summary of the details of the major subroutines of this program is included in Appendix D. The Power Plant Economic Model computer program (Reference 2) was written in the FORTRAN-IV compiler language for The Aerospace Corporation's CDC 7600 computer.

4.3.2 Levelized Fixed Charge Method

An alternative method to the discounted cash flow or present value economic evaluation of power plants is the levelized fixed charge method. This method is widely used in the utility industry for quick calculation of the busbar energy cost.

The levelized fixed charge method, shown in Figure 4-2 computes the busbar energy cost by adding the fixed and variable cost components. As will be shown in detail in Appendix E, the levelized fixed charge method is derived from the discounted cash flow methodology, and when applied correctly, will yield equivalent results. Levelized values of fuel and operating and maintenance costs must be input which, when combined with the levelized fixed charges as estimated by the levelized fixed charge rate, result in a levelized busbar energy cost. These levelized values do not reflect the actual costs experienced in any particular year during the operational lifetime of the plant.

Typical values for the levelized fixed charge rate (FCR) are shown in Table 4-6 for both private and municipal utility companies. These levelized fixed charge rates were derived from the discounted cash flow analysis as discussed in Appendix E of this report. As can be seen, the FCR is a function of the financial structure (equity debt) and costs of financing, the corporate tax rate, plant operational lifetime and salvage value of the investment. Also shown is the after-tax-cost-of-capital,

GENERATION COST

- BUSBAR ENERGY COST = FIXED CHARGES + INCR. FUEL COST + O & M

$$BBEC = \frac{CC \times FCR}{CF \times 8.76} + \frac{HR \times FC}{10^5} + O\,\&\,M$$

WHERE

CC = CAPITAL COST, \$/KW*
FCR = FIXED CHARGE RATE, %/year
CF = CAPACITY FACTOR, %
HR = HEAT RATE, BTU/KWH
FC = LEVELIZED FUEL COST, ¢/MILLION BTU
O&M = LEV. OPERATING AND MAINTENANCE COST, MILLS/KWH

FIXED CHARGES

- FIXED CHARGES = DEPRECIATION + COST OF MONEY + INSURANCE + TAXES
- FIXED CHARGE RATE IS LEVELIZED AVERAGE DISCOUNT EXPRESSED AS PERCENT OF CAPITAL INVESTMENT AT YEAR OF COMMERCIAL OPERATION

* YEAR OF COMMERCIAL OPERATION

Figure 4-2. Levelized Fixed Charge Method

Table 4-6. Levelized Fixed Charge Rate (FCR)

UTILITY TYPE	COST OF COMMON EQUITY (k_C)	COST OF PREFERRED EQUITY (k_P)	COST OF LONG-TERM DEBT (k_D) (before taxes)	PERCENT OF COMMON EQUITY (C/V)	PERCENT OF PREFERRED EQUITY (P/V)	PERCENT OF LONG-TERM DEBT (D/V)	COMPOSITE CORPORATE TAX RATE (τ)	COST-OF-CAPITAL (k) (after taxes)	PLANT OPERATING LIFE-TIME (N)	LOCAL TAXES OR PAYMTS (percent of orig. inv.)	LEVELIZED FIXED CHARGE RATE (FCR)
PRIVATE	10	6	6	40	10	50	40	6.4	30	2	15.4
	10	-	6	50	-	↓	↓	6.8	↓	↓	15.9
	12	-	8		-	↓	↓	8.4	↓	↓	19.1
	12	8	8	40	10	↓	↓	8.0	↓	↓	18.6
	↓	↓	↓	↓	↓	↓	↓	↓	↓	1	17.6
	↓	↓	↓	↓	↓	↓	↓	↓	↓	3	19.6
	↓	↓	↓	↓	↓	↓	50	7.6	↓	2	19.8
	↓	↓	↓	↓	↓	↓	40	8.0	25	↓	18.9
	↓	↓	↓	↓	↓	↓	↓	↓	20	↓	19.6
MUNICIPAL	N/A	N/A	5	N/A	N/A	100	0	5.6	30	2	8.5
	↓	↓	6	↓	↓	↓	↓	6.0	↓	↓	9.3
	↓	↓	7	↓	↓	↓	↓	7.0	↓	↓	10.1
	↓	↓	8	↓	↓	↓	↓	8.0	↓	↓	10.9

as determined by the financial structure of the utility. In the case of municipal utility companies, no taxes are levied and the cost of financing is usually by means of debt only, often in the form of tax-free municipal bonds.

Even though the levelized fixed charge method appears simple at first glance, the correct use of this method is often quite complex (particularly in comparing solar and conventional power concepts), and consequently, time consuming as well as subject to errors in interpretation.

The levelized fixed charge method is illustrated in Figure 4-3. Shown in this chart are the variable cost (fuel; operating & maintenance) and fixed charge components that make up the busbar energy cost in current dollars over the lifetime of the plant. As can be seen, the busbar energy cost and variable costs increase during the lifetime, while the fixed charges typically decrease. All costs (mills/KWH) are expressed in current dollars.

The levelized values of these costs as derived by either the discounted cash flow or the fixed charge methods are also indicated in this chart. The levelized costs fall somewhere in between the first and last year DCF costs as indicated by the bar chart. The levelized values are constant costs over the lifetime of the plant which give the equivalent net present value when discounted at the cost-of-capital as the actual current costs.

This chart indicates clearly the limitations of the fixed charge method. The busbar energy cost obtained represent a levelized rather than a current value, and the need for levelized fuel and operating and maintenance costs can be confusing to those

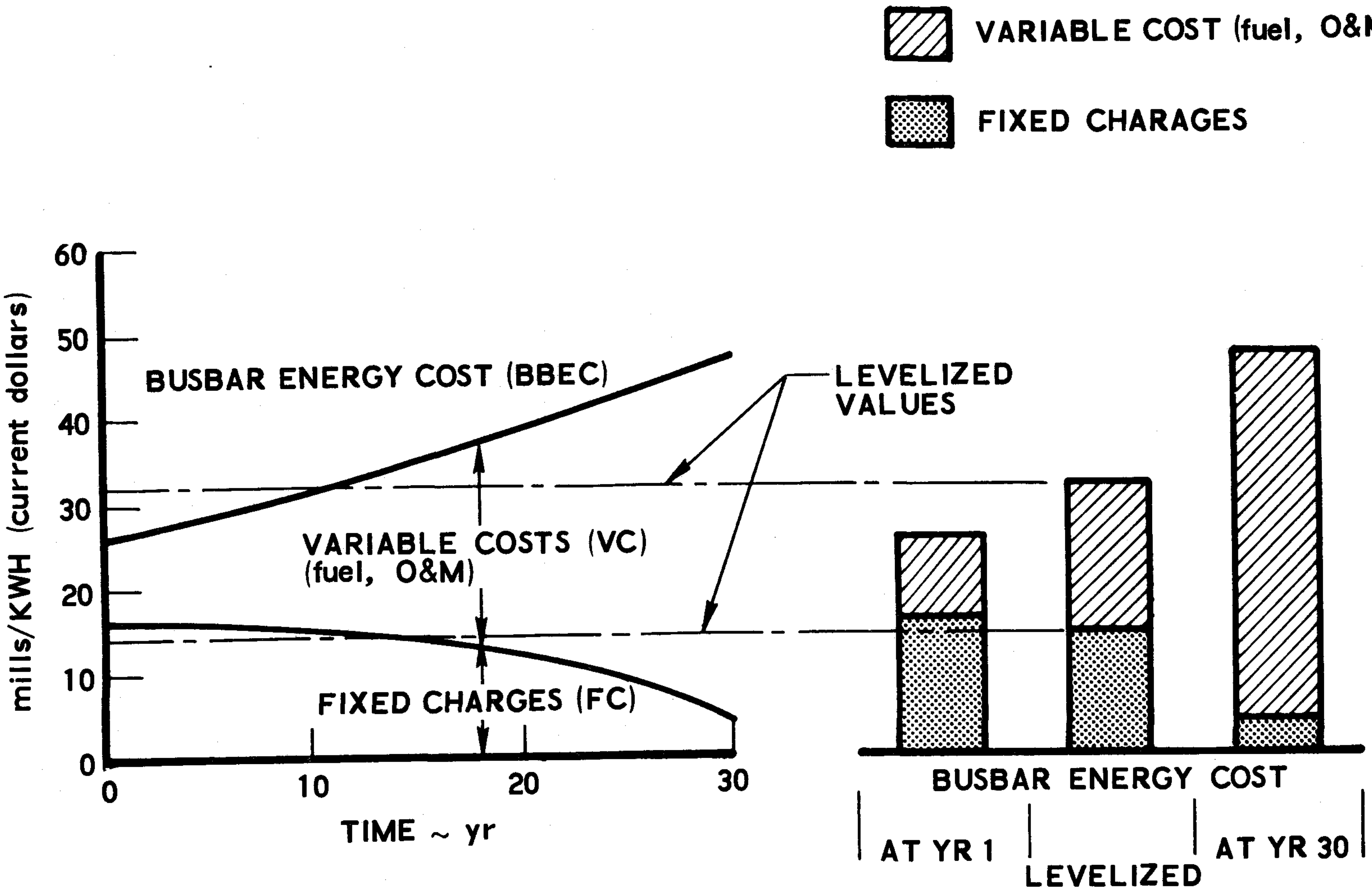


Figure 4-3. Levelized Fixed Charge Method

familiar with current (non-levelized) fuel and operating and maintenance costs.

In the comparative economic evaluation of the alternative solar thermal conversion systems and conventional power plants, the more flexible computerized discounted cash flow method, as described previously, was used.

4.4 POWER PLANT CAPITAL COST ESTIMATES

The power plant capital costs that are presented in this section refer to the estimated cost of new power plants (with a 1990 year of commercial operation) assuming a general inflation rate of three percent per year over the time period 1973-1990. These costs are not representative of the average capital costs of power plants in existence in 1990, but refer only to the marginal capital costs of additional plants which begin operation in 1990.

4.4.1 Conventional Power Plant Capital Cost Estimates

The comparative 1990 capital cost estimates of representative conventional nuclear, and fossil plants are shown in Table 4-7. The representative conventional base load plants are a pressurized water reactor (PWR) nuclear, and a low-sulphur coal fossil plant, respectively, each with a base load rating of 1,000 MWe. The 400 MWe combined cycle plant is representative for intermediate load applications and the 100 MWe gas turbine plant for peaking application.

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 construction costs, geology, water

Table 4-7. Power Plant Capital Cost Estimates, Conventional Systems ($/KWe)

	NUCLEAR (PWR) (1000)	FOSSIL (coal) (1000)	COMBINED CYCLE (400)	GAS TURBINE (100)
LAND	1	1		
STRUCTURES AND FACILITIES	54	31		
REACTOR/BOILER PLANT	75	72		
TURBINE PLANT EQUIPMENT	79	58		
ELECTRIC PLANT EQUIPMENT	30	15		
MISC PLANT EQUIPMENT	5	4		
ALLOWANCE FOR COOLING TOWERS	27	19		
SO_2 REMOVAL SYSTEM	--	31		
ZERO RADWASTE SYSTEM	4	--		
TOTAL DIRECT COST	275	231		
CONTINGENCY ALLOWANCE	19	17		
SPARE PARTS ALLOWANCE	1	1		
INDIRECT COSTS	68	61		
TOTAL CAPITAL INVESTMENT (1973)	363	310	179	115
ESCALATION TO START OF CONSTRUCTION	154	153	99	75
TOTAL AT START OF CONSTRUCTION	517	463	278	190
INTEREST DURING CONSTRUCTION	102	65	28	13
ESCALATION DURING CONSTRUCTION	125	86	36	16
TOTAL COST AT YEAR OF COMMERCIAL OPERATION (1990 dollars)	744	614	342	219

availability, land prices, etc., could cause capital costs to vary from the information presented. Added to the FPC accounts are allowances for environmental protection systems and cooling tower variations which apply as appropriate. The nuclear, coal, and solar power plants assume siting in arid areas, requiring the use of dry cooling towers.

All components of the total capital-investment-cost accounts, including contingency, spare parts, and indirect costs, are in 1973 dollars. The 1990 cost in current dollars is the sum of the 1973 cost, the escalation to start of design and construction, and the interest during construction. The escalation and interest during construction are functions of the cash expenditure flow rates for each investment account.

4.4.2 Central Receiver Power Plant Capital Cost Estimates

Representative stand-alone and hybrid central receiver solar thermal conversion power plant capital cost estimates are shown in Table 4-8 for base, intermediate, and peaking load applications, respectively. Characteristics of each of these solar plants are those described and analyzed in the preceding comparative technical evaluation. Each plant has a turbine/generator rating of 100 MWe, and the numbers 1.5/12; 1.0/6; 0.5/3; and 0.5/0.5, refer to the respective collector areas (in km^2) and storage capacities (in hours).

The capital investment costs, (in 1973 dollars) as shown in 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 (in 1990 dollars). The capital costs are shown by investment account, (in $/KWe) in accordance with the account structure used by the Federal Power Commission. Three additional accounts are shown specifically for solar plants: heliostats/collectors; receiver/tower/heat exchanger, and thermal storage/tanks.

Table 4-8. Power Plant Cost Estimates, Central Receiver Concept (100 MWe (Rated) ($/KWe)

PLANT TYPE	BASELOAD	INTERMEDIATE	PEAKING	HYBRID
COLLECTOR AREA (KM^2)	1.5	1.0	0.5	0.5
STORAGE TIME (hr)	12	6	3	0.5
ACCOUNT				
LAND	3	2	1	1
STRUCTURES AND FACILITIES	44	44	44	51
HELIOSTATS*	450	300	150	150
CENTRAL RECEIVER/TOWER**/HEAT EXCH.	124	95	68	68
STORAGE/TANKS***	180	90	45	7
BOILER PLANT	-	-	-	73
TURBINE PLANT EQUIPMENT	80	80	80	80
ELECTRIC PLANT EQUIPMENT	21	21	21	21
MISC PLANT EQUIPMENT	4	4	4	4
ALLOWANCE FOR COOLING TOWERS	20	20	20	20
TOTAL DIRECT COST	926	656	433	475
CONTINGENCY ALLOWANCE	51	39	27	32
SPARE PARTS ALLOWANCE	5	3	2	3
INDIRECT COSTS	92	78	66	88
TOTAL CAPITAL INVESTMENT (1973)	1074	776	528	598
ESCALATION TO START OF CONSTRUCTION	381	296	213	270
TOTAL AT START OF CONSTRUCTION	1455	1072	741	868
INTEREST DURING CONSTRUCTION	152	119	88	105
ESCALATION DURING CONSTRUCTION	218	169	121	156
TOTAL COST AT YR OF COMM'L OPN. (1990 dollars)	1825	1360	950	1129

* Collector Cost - $30/$M^2$
** Tower Height - 260 M (3, 2, 1, 1 Tower(s), Respectively)
*** Thermal Storage Cost - $15/KW/hr

These costs reflect the cost estimates of other NSF system contractors. The heliostat cost of $30/m^2 as shown in this table represents the lowest cost estimate. A more representative cost may be $40/m^2, other estimates indicate collector costs as high as $70/m^2. The impact of increasing the collector cost can be estimated from the cost sensitivity analysis shown in Table 4-14. The impact of thermal storage cost was evaluated parametrically by considering $15/KWH(e) and $30/KWH(e) unit storage costs.

4.4.3 Intermediate Load Solar Power Plant Capital Cost Estimates

Solar thermal conversion solar power plant cost estimates for the alternative solar collector concepts analyzed for intermediate power application are shown in Table 4-9.

The technical and performance characteristics of these alternative solar plants are described and analyzed in the preceding comparative technical evaluation. Each plant has a turbine/generator rating of 100 MWe. The collector areas and thermal storage capacities, derived from the comparative economic analysis and corresponding to the lowest attainable busbar energy cost, are shown in Table 4-9 for each concept. Also shown are the unit collector cost estimates based upon the various system contractor designs. The collector costs shown represent the lowest cost estimates; other cost estimates indicate unit collector costs as much as twice the values shown. However, in most cases, the relative costs for the alternative collectors remain similar to those shown. Consequently, the conclusions drawn from the comparative economic evaluation remain valid, even though the absolute cost estimates may vary.

Besides the collector cost and energy storage cost, thermal transport costs are another significant capital cost for the distributed systems, as

Table 4-9. Solar Thermal Power Plant Cost Estimates \$/KWe (100 MWe (Rated)

PLANT TYPE	C.R.	DISH	POLAR	N-S	E-W	E-W
COLLECTOR AREA (KM^2)	1	1.15	1.20	1.2	1.5	1.5
COLLECTOR COST (\$/m^2)	30	60	70	60	60	15
STORAGE CAPACITY (hr)/COST ~\$15/KW_e/hr	6	8	8	8	8	8
ACCOUNT						
LAND	2	2	2	2	3	3
STRUCTURES AND FACILITIES	44	49	49	49	49	49
HELIOSTATS/COLLECTORS	300	690	875	720	900	225
RECEIVER/TOWER/HEAT EXCHANGER/THERMAL TRANSPORT	95	244	319	254	318	318
STORAGE/TANKS	90	120	120	120	120	120
TURBINE PLANT EQUIPMENT	80	80	80	80	80	80
ELECTRIC PLANT EQUIPMENT	21	21	21	21	21	21
MISC PLANT EQUIPMENT	4	4	4	4	4	4
ALLOWANCE FOR COOLING TOWERS	20	20	20	20	20	20
TOTAL DIRECT COST	656	1230	1490	1270	1515	840
CONTINGENCY ALLOWANCE	39	72	88	74	89	45
SPARE PARTS ALLOWANCE	3	8	10	8	10	5
INDIRECT COSTS	78	90	101	92	102	78
TOTAL CAPITAL INVESTMENT (1973)	776	1400	1689	1444	1716	968
ESCALATION TO START OF CONSTRUCTION	296	499	603	515	614	342
TOTAL AT START OF CONSTRUCTION	1072	1899	2292	1959	2330	1310
INTEREST DURING CONSTRUCTION	119	178	210	183	214	127
ESCALATION DURING CONSTRUCTION	169	291	355	301	360	198
TOTAL COST AT YR COMMERCIAL OPERATION (1990 dollars)	1360	2368	2858	2443	2904	1635

can be seen in Table 4-9. The higher unit collector and thermal transport costs for the polar-oriented parabolic trough as compared to the E-W or N-S orientation is due to increased installation, structural, and pipe costs associated with the inclined attitude (equal to the local latitude) of the collectors.

Also shown in the last column is the capital cost estimate for an E-W oriented parabolic trough power plant using a low-cost collector concept. As will be shown in Figure 4-15, in order to be economically competitive with conventional power plants operating in the intermediate range, an unit collector cost of $\$15/m^2$ must be achieved. Low cost E-W parabolic collector concepts, such as the fixed trough/movable absorber (Gulf Atomic) concept, the Winston type of collector, or the sigmented mirror (Fresnel) concept have been proposed. However, no detailed system cost analyses are available for these concepts to assess if the $\$15/m^2$ cost objective is attainable for these concepts.

4.5 OPERATING COSTS

The principal component of operating of variable 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

Typical nuclear fuel cycle costs, including carrying charges, were 2.13 mills/KWH in 1972. This included a direct fuel cost of 1.5 mills/KWH (Reference 10) and an additional carrying charge of 42 percent (Reference 11).

A study of future nuclear fuel cycle cost was made on the basis of calculated future uranium prices and an assumed escalation rate (4%) for the other elements of nuclear fuel cycle costs. The future demand of uranium ore (U_3O_8) was obtained by using Atomic Energy Commission (AEC) forecasts of uranium requirements to the year 2000 and a projection of nuclear generating capacity (and associated fuel requirements) beyond 2000 (Reference 12). The commercial availability of fast breeder reactors was assumed beginning in the 1990 time period and beyond. The supply of U_3O_8 at various prices per pound was obtained from AEC publications (Reference 12). Included in the U_3O_8 prices were allowances for land reclamation costs (Reference 13). The resulting nuclear fuel cycle costs are shown in Table 4-10. The average escalation rate over the time period 1972 to 2000 is 5.3 percent per year.

4.5.2 Fossil Fuel Costs

Projected 1980 fuel costs and escalation rates for various areas of the Southwestern United States were developed for this study. Projected prices for coal and natural gas are shown in Table 4-11 for the year 1980. No projected price of oil was developed as current oil prices may preclude its consideration for new power plants.

The 1980 coal prices for each area were based on five factors: (1) mine-mouth coal price, (2) coal price escalation rate, (3) transportation cost from mine to consumption area, (4) escalation rate for transportation cost, and (5) land reclamation costs. Mine-mouth 1972 coal prices per million BTU were obtained for two locations; Four Corners, Arizona (14.7¢/MBTU) area and Hanna, Wyoming (15.0¢/MBTU) (Reference 14).

The coal escalation rate was obtained from a National Petroleum Council Study of Western Coal Mining Economics as a function of overburden ratios (Reference 15). Based on the extensive reserves of strippable coal, the constant dollar increase in the cost of coal due to reserve depletion was determined to be 0.8%/year. This rate combined with the

TABLE 4-10
NUCLEAR FUEL COSTS
(MILLS/KWH)

(CURRENT DOLLARS)

Year	Fabrication and Enrichment*	U_3O_8	Carrying Cost	Total
1972	1.04	.46	.63	2.13
1985	1.73	.68	1.01	3.42
1990	2.11	1.29	1.43	4.83
2000	3.12	3.30	2.70	9.12

*Includes fabrication, enrichment, conversion, reprocessing, shipping, and plutonium credit.

assumed 3%/year rate of inflation results in a current dollar coal escalation rate of 3.8%/year. Coal transportation costs were obtained for unit train shipments (Reference 15), and a 3%/year escalation rate was assumed for these coal transportation costs. Transport distances to each area were used to determine transportation costs (Reference 16). The last factor to be incorporated is the land reclamation cost. A \$0.30/ton levy (1.67¢/MBTU based on 9,000 BTU/lb was incorporated into legislation by a House Subcommittee (Reference 17). This amount was added to 1980 coal costs.

Natural gas prices were developed for two gas supply sources: (1) conventional domestic natural gas production*, and (2) new sources. New sources were: liquid natural gas (LNG) imports to the West Coast, coal gasification, and gas supply from the Arctic. Cost estimates were obtained for each new source, which were converted to 1980 dollars and averaged (Reference 18, 19). An escalation rate of 3% per year was assumed for the delivered cost of gas from new sources. Projected future constant dollar conventional domestic natural gas wellhead prices were used to obtain a constant dollar escalation rate (Reference 13). This rate combined with the assumed inflation rate of 3%/year provided the escalation rates for conventional domestic wellhead gas prices. The national average 1972 wellhead gas price was escalated to 1980 and combined with transmission costs (Reference 20). Transmission costs were assumed to increase at the general inflation rate of 3%/year. Delivered prices were derived for two areas: Area 1 - Southern California, Nevada, Arizona, and New Mexico; and Area 2 - Texas and Oklahoma. The supply

*Lower 48 states only.

of gas in Area 2 was assumed to be entirely from conventional domestic sources. The gas supply to Area 1 was assumed to have an increasing proportion of supplies from new sources: 1980 - 25%, 1990 - 33%, 2000 and later - 50%. The remaining proportion of supply for Area 1 was from conventional domestic sources. Thus the gas price and escalation rates shown in Table 4-11 for Area 1 are composites.* Further studies are now underway at The Aerospace Corporation in conjunction with the Department of Interior that will greatly expand and update natural gas pricing information beyond the limited analyses permitted within the Solar Thermal Conversion Mission Analysis.

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 (Reference 21). The ORNL cost data are for base load plants and include 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 4-12 shows the O&M cost estimates.

Table 4-13 shows the insurance and property tax cost estimates for private utility companies. The insurance costs were obtained from ORNL (Reference 21). The insurance rate for the solar plant is slightly less than the rate for fossil plants because no insurance coverage is required for the thermal storage material. The property tax rate for the

*The average 1980 price for gas from new sources is $1.36/MBTU; the delivered price from conventional domestic sources is $0.62/MBTU. It is recognized that the composite average price is likely to be lower than the price new power plants would pay for marginal supplies of gas in the future.

TABLE 4-11

1980 DELIVERED FOSSIL FUEL COSTS & ESCALATION RATES

Fuel & Area	Fuel Price ¢/MM BTU	Escalation Rates/Year 1980-1990	1990-2000*
Coal			
Albuquerque, New Mexico	35.6	3.4	3.4
El Paso, Texas	45.4	3.4	3.4
Fort Worth, Texas	65.2	3.3	3.3
Mohave Nevada	32.5	3.5	3.5
Phoenix, Arizona	47.4	3.4	3.4
Natural Gas			
Area 1	80.5	5.7%	5.4%
Area 2	46.7**	7.8%	7.4%

*Escalation rates for 1990-2000 were assumed for time periods beyond 2000.

**Quantity limited, the intra-state price is about double this level.

Area 1 - So. California, Nevada, Arizon, New Mexico

Area 2 - Oklahoma, Texas

TABLE 4-12
OPERATION & MAINTENANCE COST ESTIMATES (1973 DOLLARS)
1000 MWe BASE POWER PLANTS
($/KWe)

Cost Category	Oil	Coal	Nuclear	Solar
O&M Basic	3.3	3.5	4.4	2.6
SO_2 Removal	* -	1.0	-	-
Dry Towers	.1	.1	.1	.1
Zero Radwaste	-	-	.2	-
O&M Solar	-	-	-	4.8
N_{ox} Control	2.0	2.0	-	-
Fly Ash	-	.1	-	-
Environmental Monitoring	.1	.1	.1	-
Total	5.5	8.2	4.8	7.5

*Fuel with sulphur content of .3%

TABLE 4-13

INSURANCE & PROPERTY TAX

LEVELIZED PERCENT OF ORIGINAL CAPITAL INVESTMENT

	Oil	Coal	Nuclear	Solar
Remote Site	.45	.45	.75	.42
Rural Site	1.20	1.20	1.50	1.17
Suburban Site	2.20	2.20	2.50	2.17

remote site assumes no municipal or school taxes, only a county property tax. The county tax rate is assumed to be \$1.00/\$100 of assessed valuation where property is assessed at 25 percent of market value. The tax rate for a rural site is assumed to be \$4.00/\$100 of assessed valuation and \$8.00/\$100 of assessed valuation for a surburban site.

4.6 COMPARATIVE ECONOMIC ANALYSIS RESULTS

A comparative economic analysis was made of stand-alone and hybrid solar power plants and conventional power plants for base, intermediate, and peaking load applications. The economic analysis methodology described in Section 4.3 was used to compare power plants with the same year of commercial operation (1990), on a consistent basis using the data standards described previously in Section 4.2 and capital and operating costs as shown in Sections 4.4 and 4.5.

In order to compute the interest during construction (IDC) the time period for design and construction was assumed to be 7-1/2 years for nuclear plants and 6 years for coal-fueled and solar plants. For combined cycle plants and the gas-turbine plants, these periods were assumed to be 4-1/2 years and 3-years, respectively.

4.6.1 Base Load Central Receiver Power Plant Economic Evaluation

The total busbar energy cost was parametrically determined for 100 MWe base load central receiver power plant configurations with characteristics and parametric performance described in the previous comparative technical evaluation.

The results of the economic evaluation are shown in carpet plot format in Figure 4-4. The first year of commercial operation (1991) total

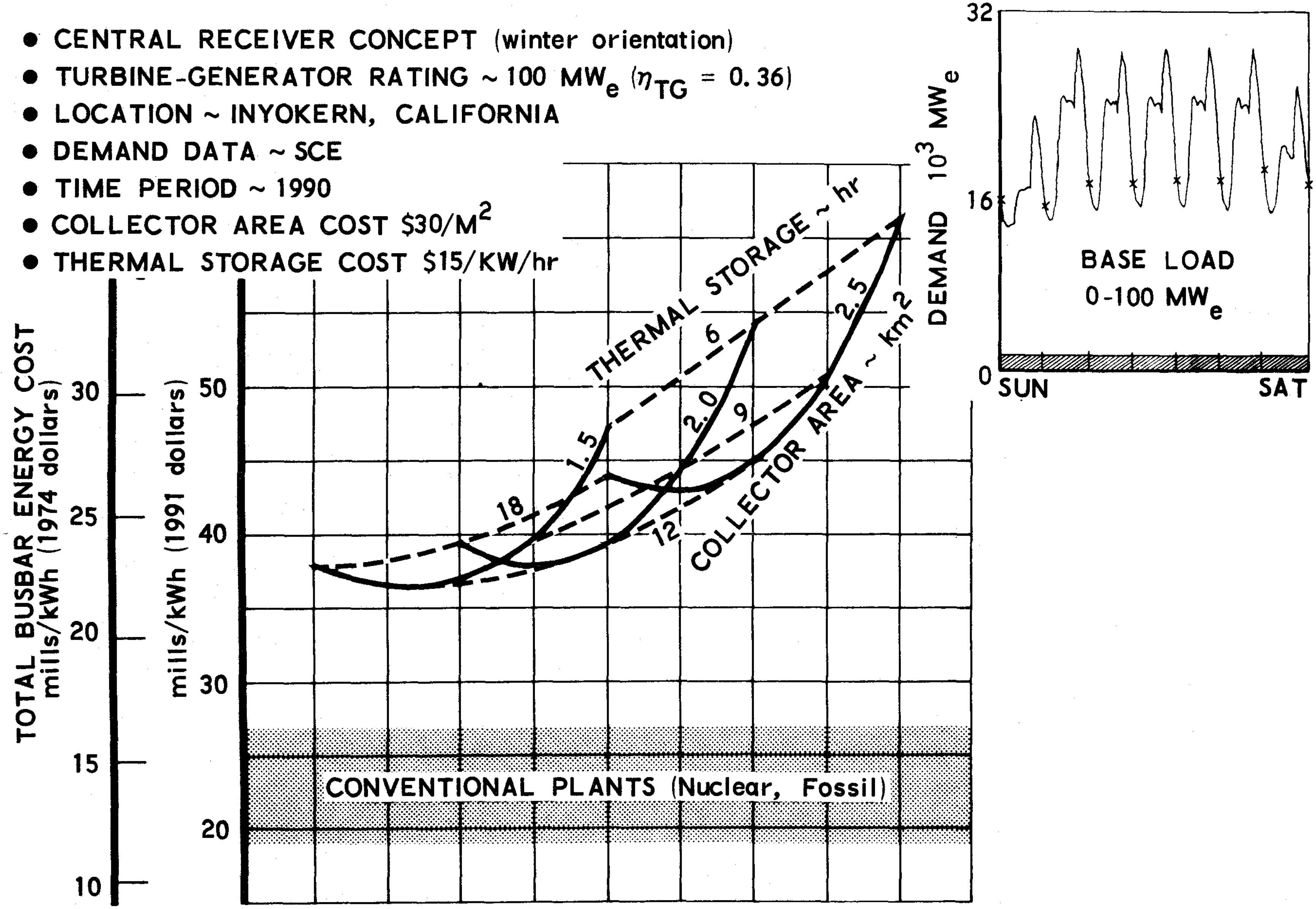


Figure 4-4. Base Load Solar Thermal Conversion Plant, Central Receiver Total Busbar Energy Cost

busbar energy costs (in current and constant 1974 dollars) are shown parametrically for various collector-area and storage-capacity combinations. The carpet plot reflects a $\$30/m^2$ collector area cost and a \$15/KWH(e) storage cost (1973 dollars).

As can be seen from this chart, for base load applications the lowest busbar energy cost (37 mills/KWH, 1991 dollars) is for a solar plant with a 1.5 Km^2 collector area and 12 hour storage capacity.

The wide band at the bottom of the figure is the busbar energy cost for 1,000 MWe conventional (nuclear and fossil) power plants. These busbar energy costs were computed using the same economic analysis methodology and data standards as used for the solar power plants. The width of the conventional busbar energy cost band (19-27 mills/KWH, 1991 dollars) reflects both nuclear (PWR) and fossil (coal) power plants with variations in the assumed plant capacity factors of 70 percent to 80 percent, as well as fuel cost variations for the fossil plants.

The comparative total busbar energy costs (in 1991 dollars) for a representative 1000 MWe base load nuclear plant, a 1000 MWe fossil power plant and a 100 MWe central receiver plant are shown in Figure 4-5. Shown is the total busbar energy cost in terms of fixed costs (cost of money, depreciation, insurance, and taxes) and variable costs (fuel and other operating costs).

The solar plant represented in Figure 4-5 has a unit collector cost of $\$30/m^2$ (1973 dollars) and the plant capacity factor was determined by system simulation for a field size of 1.5 km^2 and 12 hours storage capacity. The investment costs for the solar, fossil, and nuclear plants shown at the bottom of the figure are those shown earlier in Tables 4-7 and 4-8.

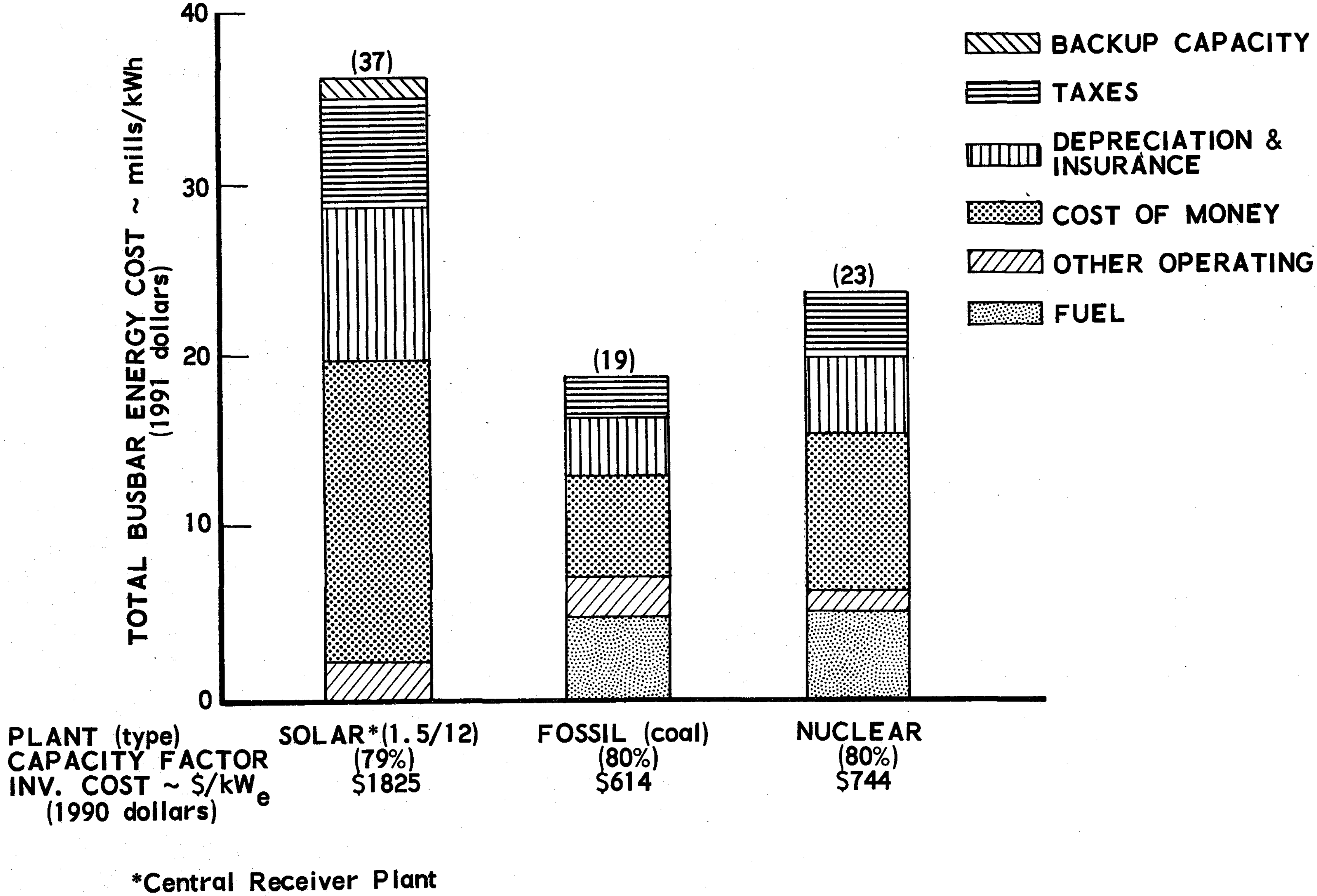


Figure 4-5. Total Busbar Energy Cost, Central Receiver Base Load

The lower busbar costs for the fossil plant is due to the low fuel cost. This fuel cost is for a plant located in southern Nevada, an area with one of the lowest fuel costs in the nation.

Included in the solar plant busbar energy cost is an allowance for back-up capacity. This is the cost for incorporating sufficient conventional back-up capacity to achieve equal utility system reliability as for a conventional plant. The rationale for and the amount of back-up capacity required was determined previously in the section describing the margin analysis.

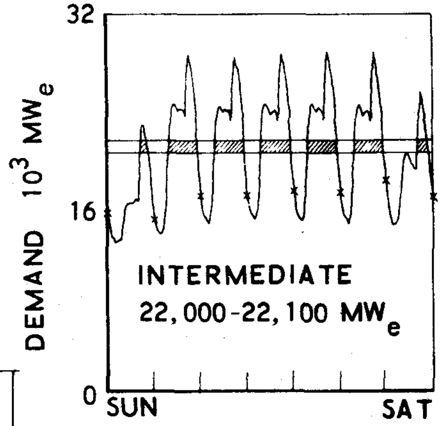
4.6.2 Intermediate and Peaking Load Central Receiver Power Plant Economic Evaluation

The total busbar energy costs for 100 MWe central receiver solar power plants for intermediate and peak 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 carpet plots reflect a $\$30/m^2$ unit-area collector cost, and a thermal storage cost of \$15/KWH(e) (1973 dollars).

Included in the solar plant busbar energy cost is an allowance for back-up capacity. This is the cost for maintaining sufficient conventional back-up capacity to achieve equal utility system reliability as for a conventional plant. The rationale for and the amount of back-up capacity required was determined previously in the margin analysis.

For intermediate and peaking solar plants, in addition to the additional fixed charge to account for conventional back-up capacity, an energy displacement credit is incorporated to account for the additional base or intermediate load energy (fuel) displacement. For this additional energy displacement, beyond the intermediate or peaking demand

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST \$30/M^2
- THERMAL STORAGE COST \$15/KW/hr



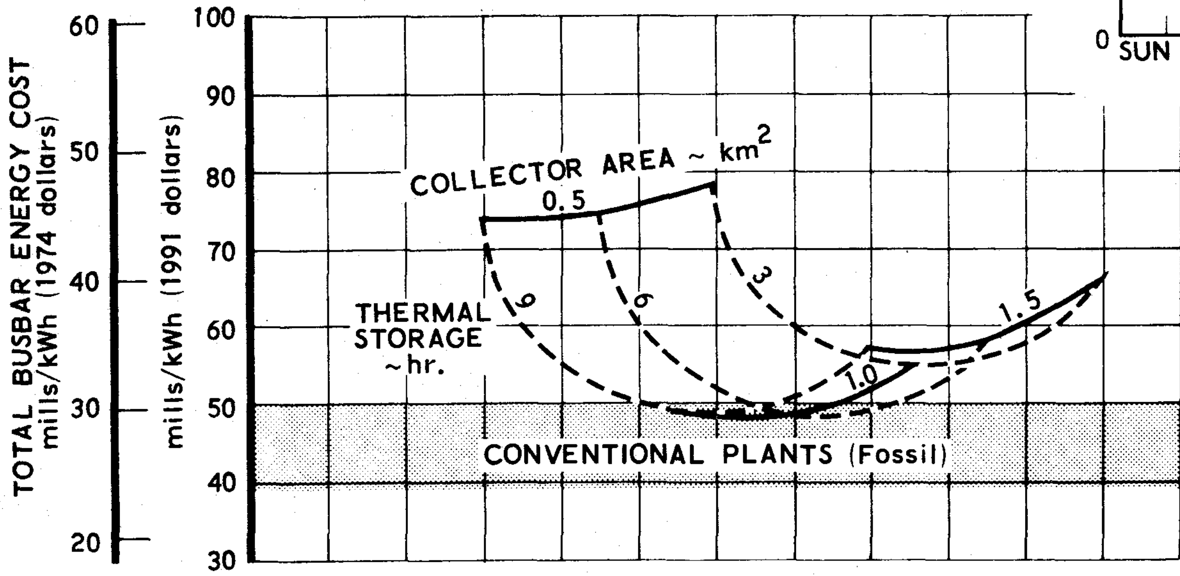


Figure 4-6. Intermediate Solar Thermal Conversion Plant, Central Receiver Total Busbar Energy Costs

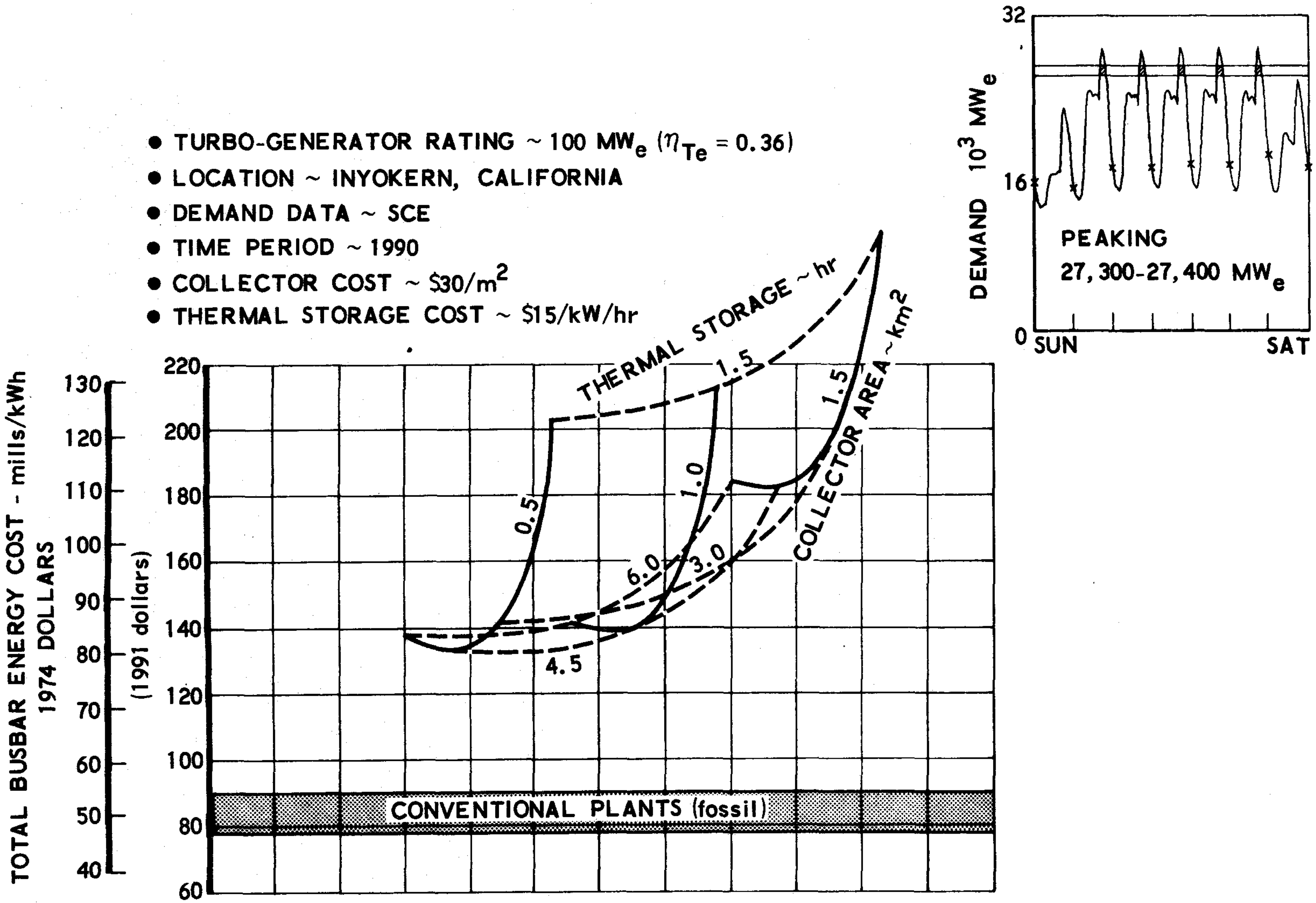


Figure 4-7. Peaking Solar Thermal Conversion Plant, Central Receiver Total Busbar Energy Cost

requirements, no additional capacity displacement was assumed.

For intermediate load application a solar plant with a 1.0 km^2 collector area and 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 0.5 km^2 collector area and 3-hours of storage capacity.

The fossil-fuel busbar energy costs for intermediate and peaking plants, as shown by the wide band in Figures 4-6 and 4-7, were based on a 400 MWe combined cycle for intermediate load and a 100 MWe gas turbine plant for peaking load applications, respectively. A 1991 fuel cost range of $1.65 to $2.40 per MBTU was assumed, with an escalation rate of 5.4 percent per year. The busbar energy costs for these intermediate and peaking fossil plants are representative of intermediate and peaking power plants for the 1990 time period.

As can be seen from Figure 4-6, the central receiver solar plant with a collector area of 1.0 km^2 and 6-hour storage capacity operating in the intermediate mode appears competitive with the intermediate load conventional power plants for the 1990 time period, assuming that the collector cost of $\$30/m^2$ can be realized.

The comparative total busbar energy costs (in 1991 dollars) for a 100 MWe intermediate load central receiver power plant and a representative conventional power plant are shown in Figure 4-8. The total busbar energy costs are shown in terms of fixed charges and variable costs. The solar plant costs include an additional fixed charge to account for any required conventional back-up capacity and an energy displacement credit to account for the fuel displaced outside the intermediate demand range. No additional capacity displacement was

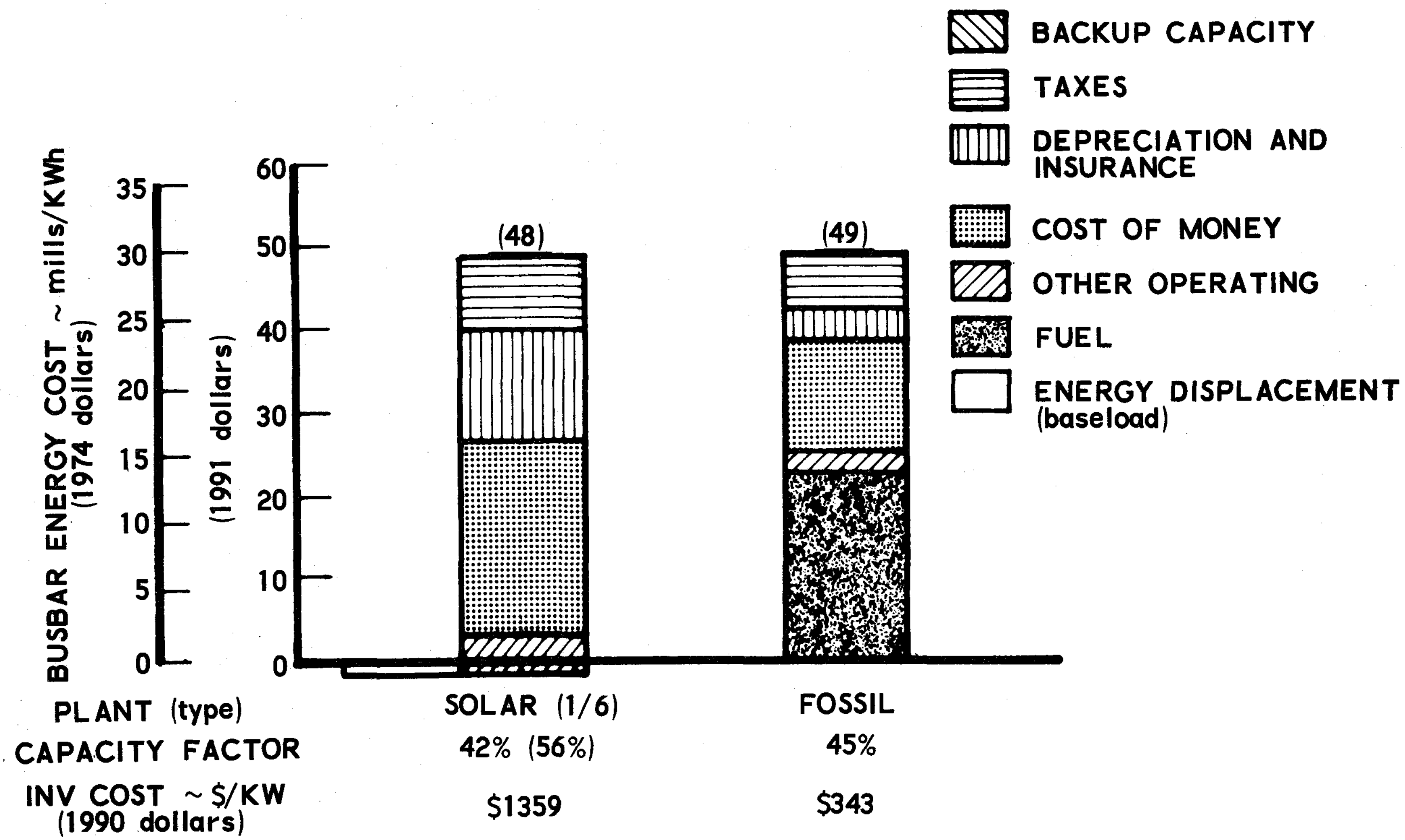


Figure 4-8. Total Busbar Energy Cost, Central Receiver Intermediate Load

considered outside of the intermediate load range. The capacity factor indicated in Figure 4-8 is for the designated intermediate range only, while the number in brackets includes the effect of the additional energy displacement.

One of the assumptions in the central receiver power plant is the cost of thermal energy storage at $15/KWH(e). Since energy storage concepts are least well defined at the present time, the sensitivity of the preceding results to this cost assumption was evaluated. Shown on Figure 4-9 is the 100 MWe intermediate load central receiver power plant busbar energy cost assuming a thermal storage cost of $30/KWH(e) as compared to the previous results reflecting the $15/KWH(e) storage cost. As can be seen, the increase in busbar cost for the intermediate central receiver plant (with 1 km^2 collector area and 6 hour storage capacity) due to doubling the storage cost is minimal (50.0 mills/KWH versus 47.5 mills/KWH, respectively, in 1991 dollars).

As is apparent from the economic evaluation of the central receiver solar power plants, the preferred mode of operation is the intermediate load application. Consequently, all the alternative solar thermal conversion system concepts considered in this study are compared for this intermediate load operational mode.

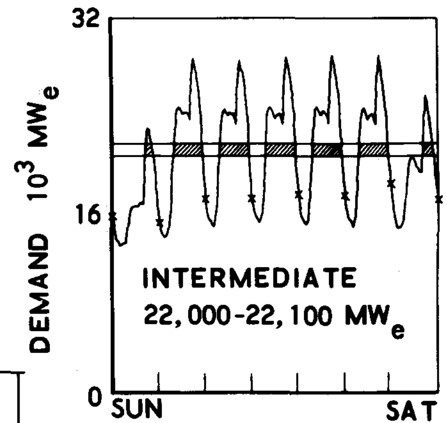
4.6.3 Intermediate Load Hybrid Central Receiver Power Plant

Because the thermal energy storage concepts are the least well defined at the present time, a hybrid power plant may be an alternative to the stand-alone solar power plant. Such a hybrid plant still requires some limited thermal storage capacity (approximately 1/2 hour) for dynamic stability of operation during short periods of intermittent cloud cover. In lieu of the long-term storage required for reliable and economic

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST \$30/M^2 — \$ 30/M^2
- THERMAL STORAGE COST \$15/KW/hr — \$ 30/KW/hr



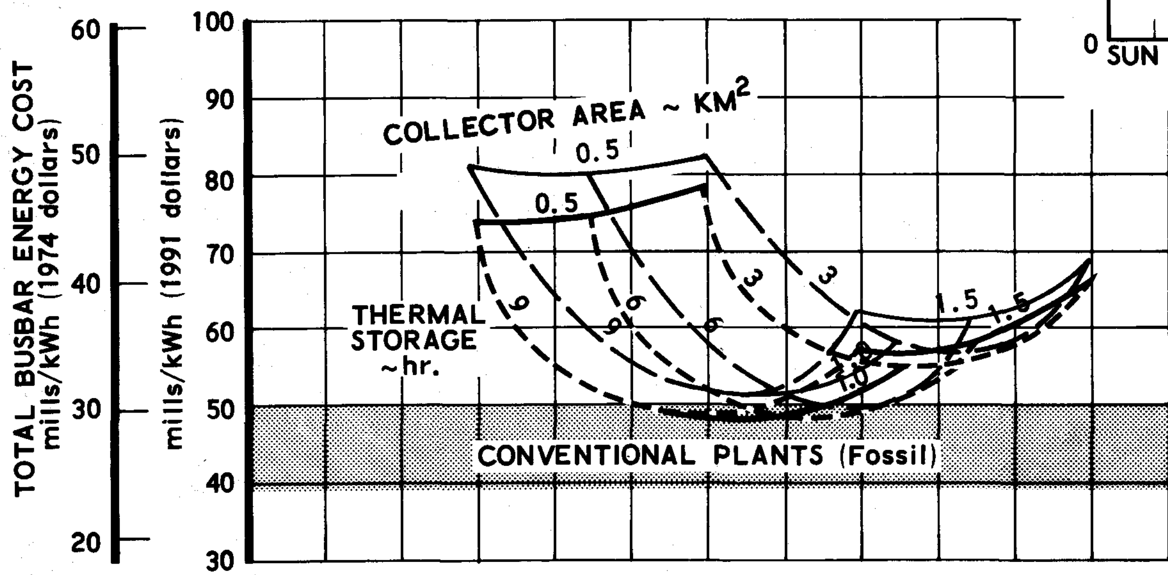


Figure 4-9. Intermediate Solar Thermal Conversion Plant, Central Receiver (winter orientation)

operation as discussed in the preceding sections, the hybrid plant incorporates a conventional fossil fueled boiler. The remainder of the plant is common for both the solar and fossil fuel thermal inputs.

Such a hybrid central receiver power plant is compared to the previously discussed stand-alone central receiver plant for the intermediate load application in Figure 4-10. The 100 MWe hybrid plant has a collector area of approximately 0.5 km^2, since no storage capacity exists to store excess energy above the turbine/generator capacity rating of 100 MWe. Both the hybrid and conventional combined cycle plant busbar energy costs are shown parametrically as a function of the fuel cost.

As can be seen from this figure, the (1991) busbar energy cost of the hybrid central receiver plant is less than for a conventional fossil plant when (1991) fuel costs rise above $2.10 per MBTU (1973 dollars). In contrast, the stand-alone central receiver plant for intermediate application is competitive with this conventional plant at (1991) fuel costs of $1.40 MBTU (1973 dollars) or higher.

4.6.4 Intermediate Load Paraboloidal Dish Power Plant

The total busbar energy costs of a 100 MWe intermediate load paraboloidal dish power plant and the previously defined intermediate load central receiver power plant are compared on a consistent basis in Figure 4-11. These data are based on a $60/$m^2$ paraboloidal dish collector cost and a thermal storage cost of $15/KWH(e) (1973 dollars).

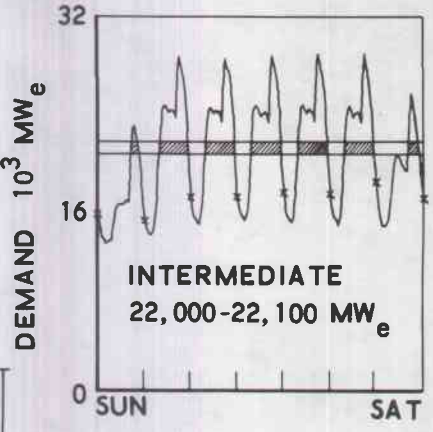
The technical performance of these alternative plants was described in the preceding comparative technical evaluation section. (Figures 2-11 and 2-12)

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

HYBRID PLANT (0.5 KM^2/0.5 hr)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST $30/M^2
- THERMAL STORAGE COST $15/KW/hr



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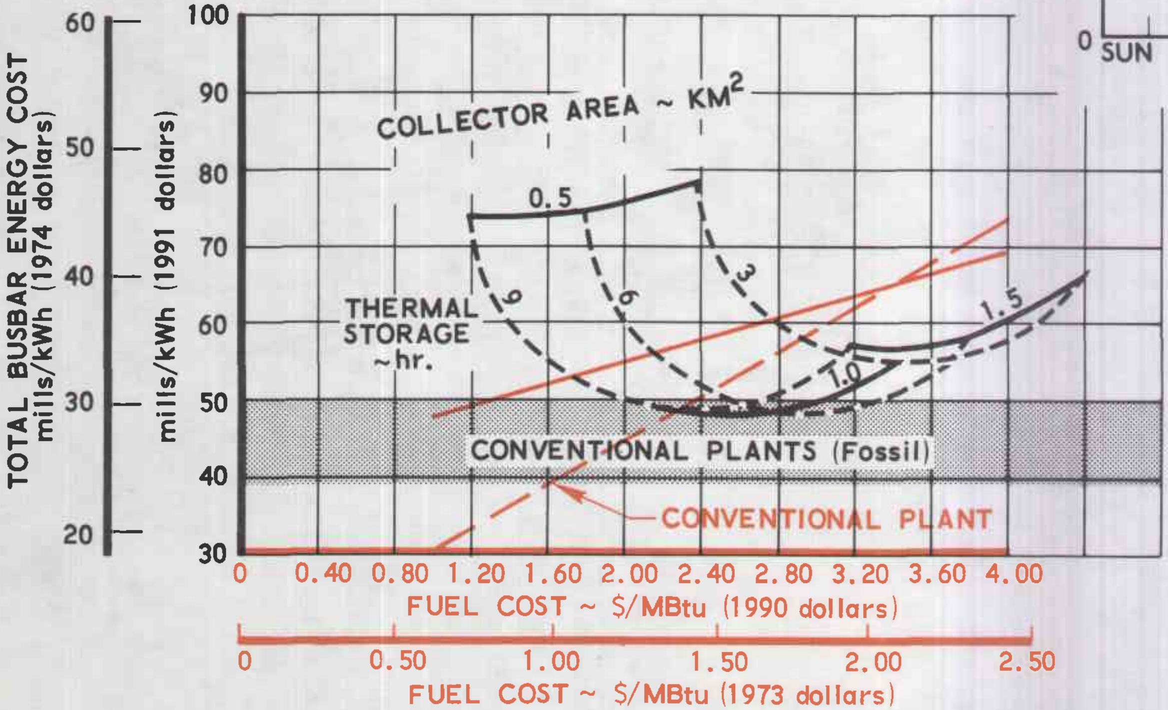

Figure 4-10. Intermediate Solar Thermal Conversion Plant, Central Receiver (winter orientation) Hybrid Plant (0.5 km^2/0.5 hr)

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

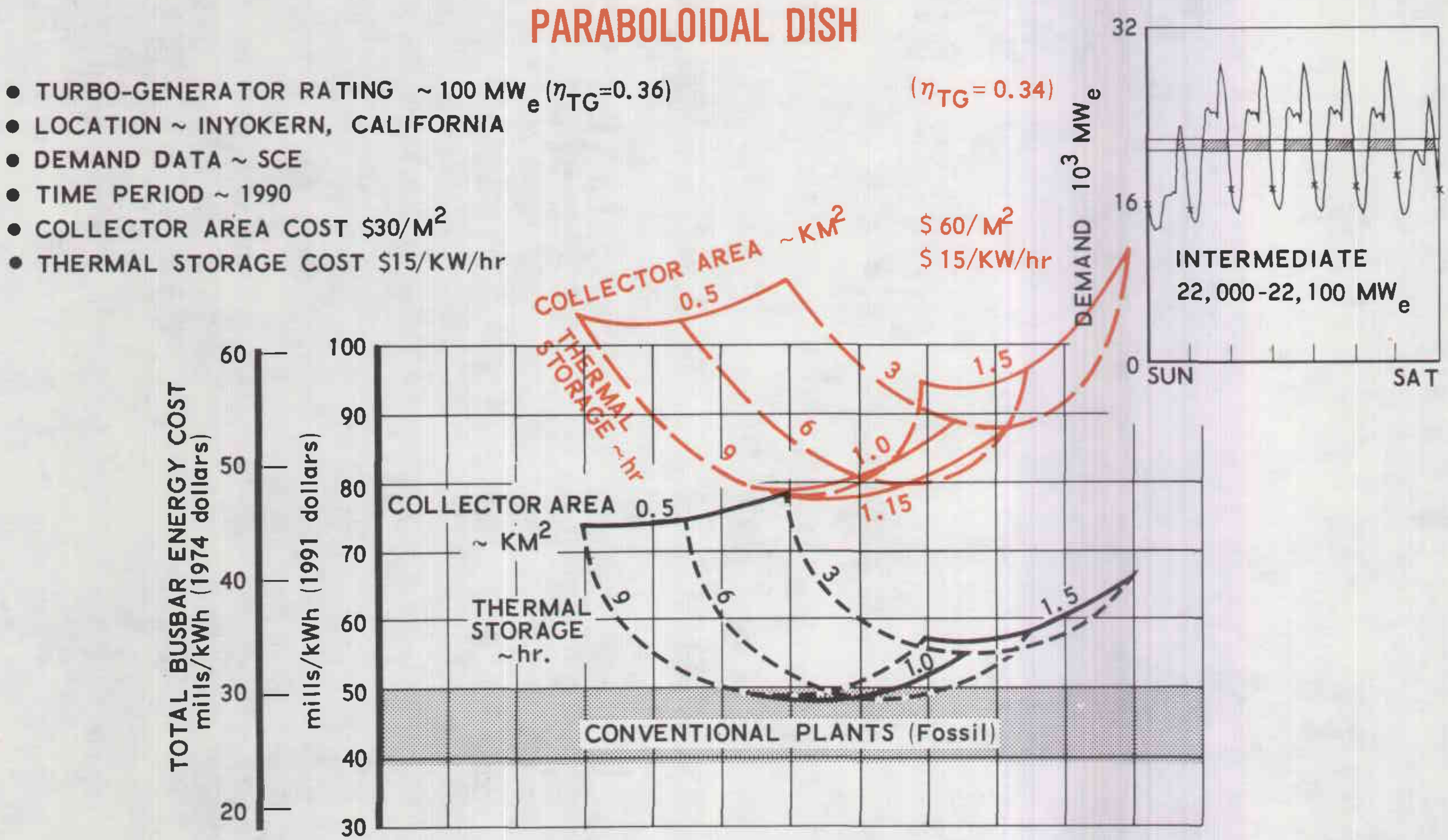

Figure 4-11. Intermediate Solar Thermal Conversion Plant, Central Receiver (winter orientation) vs. Paraboloidal Dish

For intermediate load application of the paraboloidal dish power plant, the combination of a 1.15 km^2 collector area and 6-hour storage capacity results in the lowest total busbar energy cost. This busbar cost is higher than the equivalent central receiver (and conventional) power plant busbar energy costs (77 mills/KWH versus 47 mills/KWH, 1991 dollars). This is due to the relatively lower technical performance, and higher unit solar collector and thermal transport costs.

4.6.5 Intermediate Load Parabolic Trough Power Plant

The total busbar energy costs of 100 MWe intermediate load parabolic trough power plants, with Polar, N-S, and E-W oriented collectors are compared in Figures 4-12, 4-13, and 4-14, respectively, with the previously defined intermediate load central receiver power plant. The carpet plots reflect a \$60/m^2 collector cost (\$70/m^2 for the polar-oriented configuration), and a thermal storage cost of \$15/KWH(e) (1973 dollars). The technical performance of these alternative plants was described in the preceding comparative technical evaluation section (Figures 2-13 through 2-15) and the corresponding investment cost data are summarized in Table 4-9 for the unit area collector costs indicated.

For each alternative parabolic trough collector configuration the combination of collector area and storage capacity resulting in the lowest busbar energy cost was determined. The resulting (1991) busbar energy costs (and associated collector area/storage capacity) are 90 mills/KWH (1.2 km^2/8 hr), 93 mills/KWH (1.2 km^2/8 hr), and 100 mills/KWH (1.5 km^2/8 hr), respectively, for the Polar, N-S, and E-W oriented parabolic trough collectors. As can be seen from these figures, the busbar energy costs are higher than for the intermediate load central receiver or conventional power plants (47 mills/KWH, 1991 dollars).

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (Polar Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 70/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

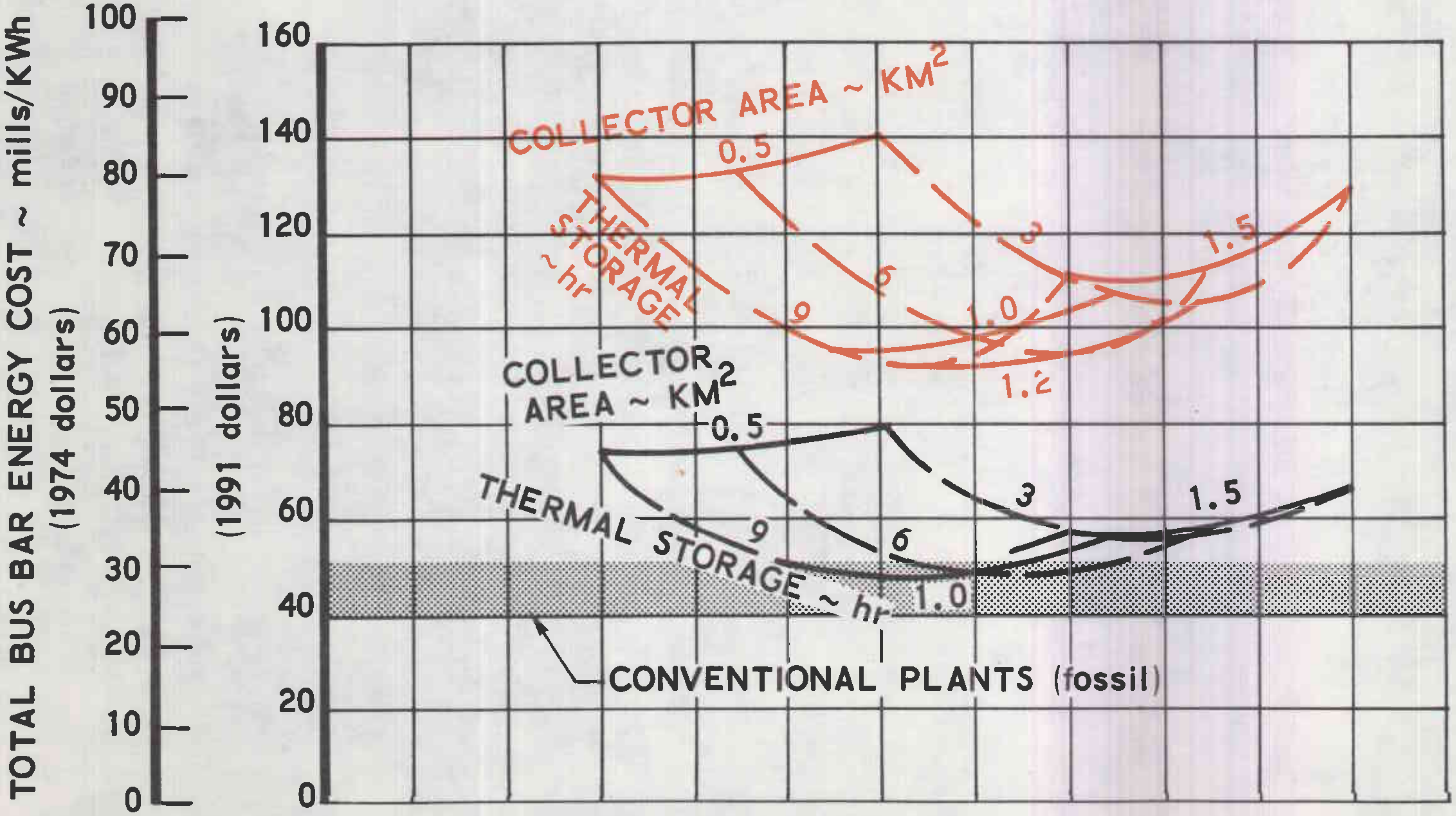

Figure 4-12. Intermediate Load Central Receiver vs. Polar Oriented Parabolic Trough Power Plant

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (N-S Orientation)

- TURBO-GENERATOR RATING ~ 100 MW$_e$ (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 60/M^2
- THERMAL STORAGE COST ~ \$15/KW$_e$/hr \$15/KW$_e$/hr

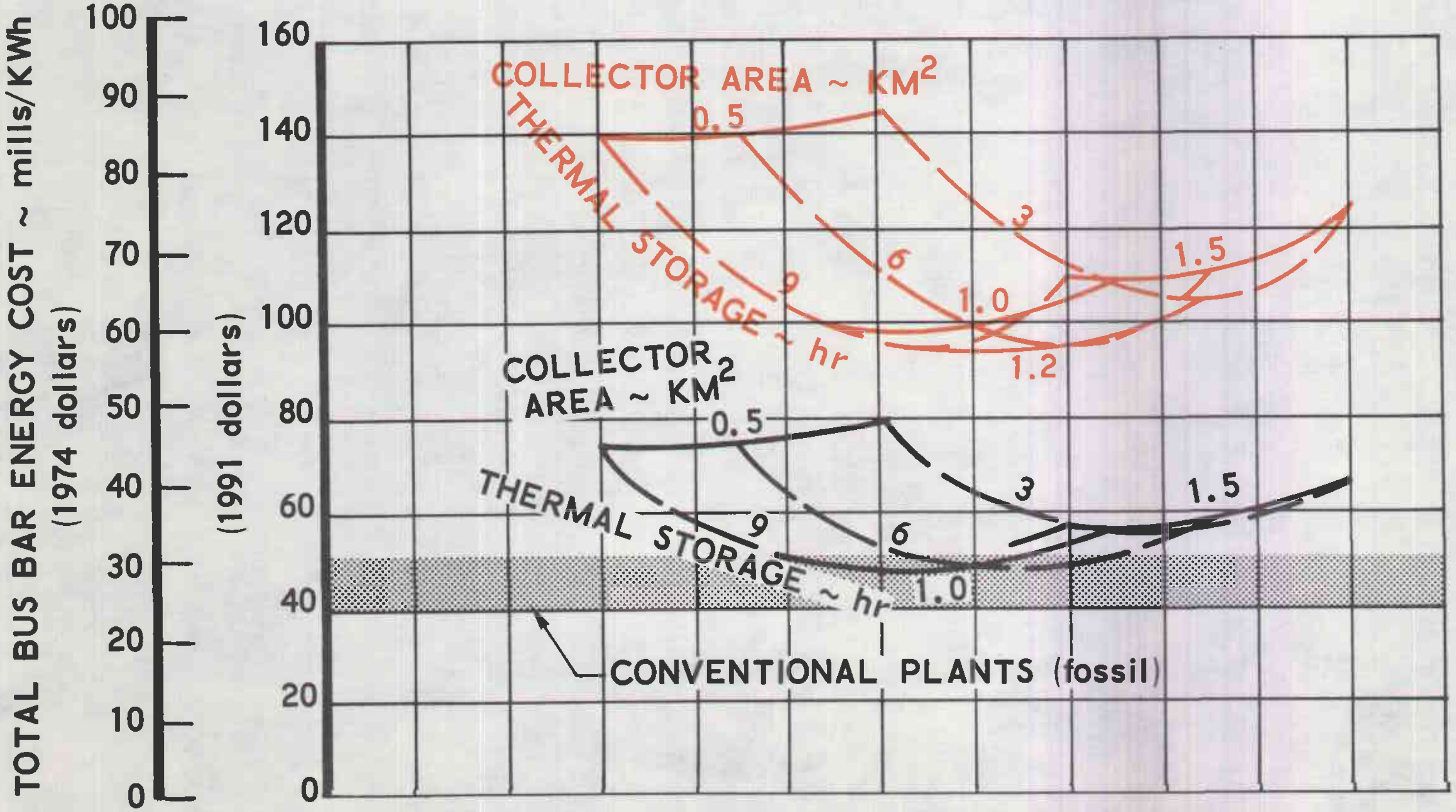

Figure 4-13. Intermediate Load Central Receiver vs. N-S Oriented Parabolic Trough Power Plant

This is a result of the relatively lower technical performance and the higher solar collector and thermal transport costs for the parabolic trough configurations.

Alternative E-W oriented parabolic-trough concepts have been proposed, which may have the potential of lower unit collector costs. As compared to the trough collector concept analyzed, these concepts include the fixed concentrator/variable receiver concept, the Winston-type concentrator, and the segmented collector concept. No detailed systems analyses have been performed to adequately define the cost-savings potential of these systems. Even though the actual cost data are not available, unit collector cost objectives can be determined based upon the technical performance which yield economically competitive busbar energy costs. These data are shown in Figure 4-15. As can be seen, if a unit collector cost of $\$15/m^2$ can be achieved with any of these alternative collector concepts, the system may be competitive with the conventional fossil intermediate load power plants for the 1990 time period.

As can be seen from this figure, the lowest busbar energy cost for a 100 MWe intermediate load plant corresponds to the combination of collector area of 1.5 km^2 and storage capacity of 8-hours.

4.6.6 Comparative Economic Evaluation - Intermediate Load Solar Thermal Conversion Power Plants

The results of the comparative economic assessment of the alternative 100 MWe intermediate load solar thermal conversion systems are summarized in Figure 4-16. Shown on this figure are the comparative busbar energy costs for these alternative systems corresponding to the individual combination of collector area and storage capacity which resulted in the lowest busbar energy cost.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (E-W Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 60/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

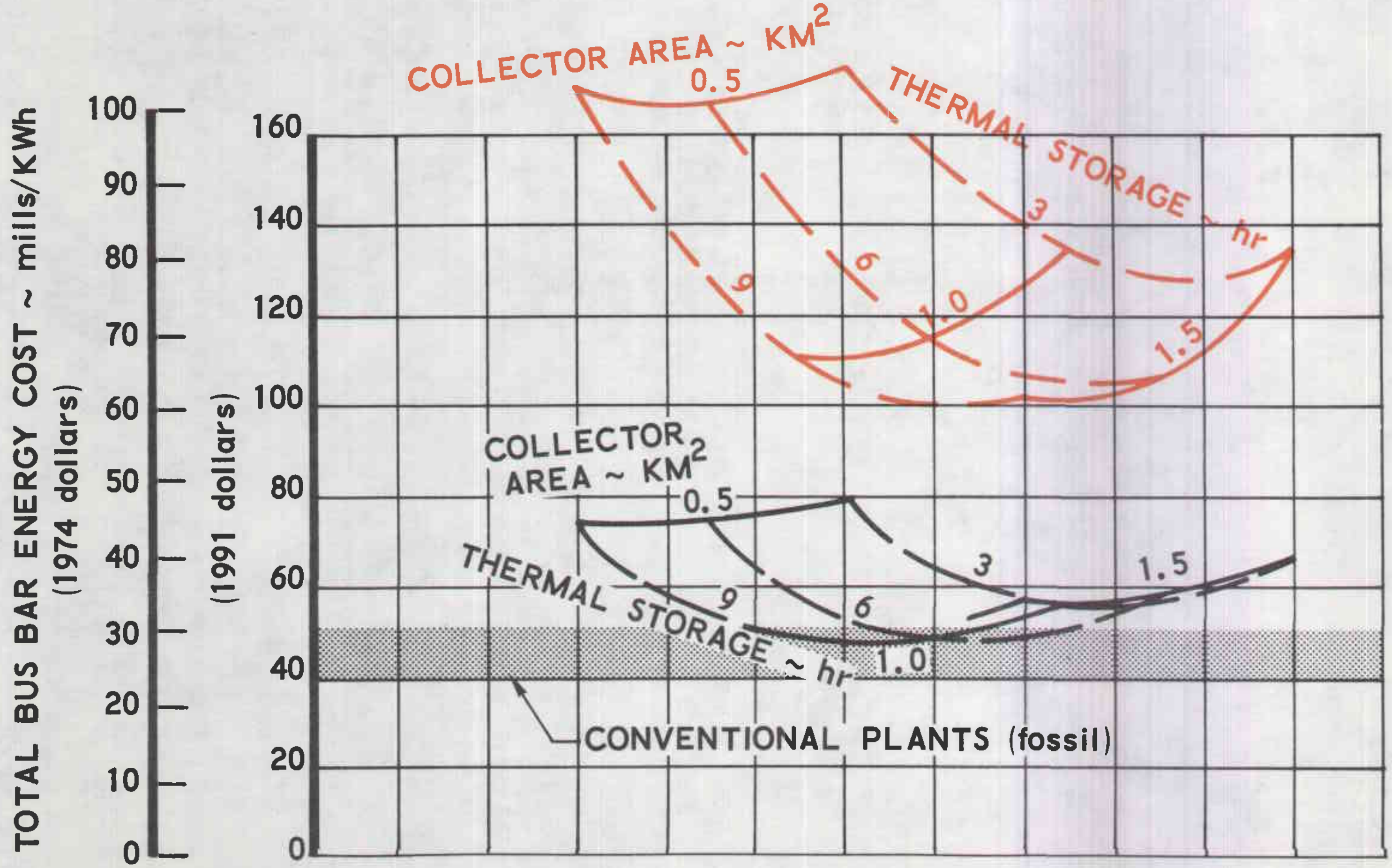

Figure 4-14. Intermediate Load Central Receiver vs. E-W Parabolic Trough Power Plant

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (E-W Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 15/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

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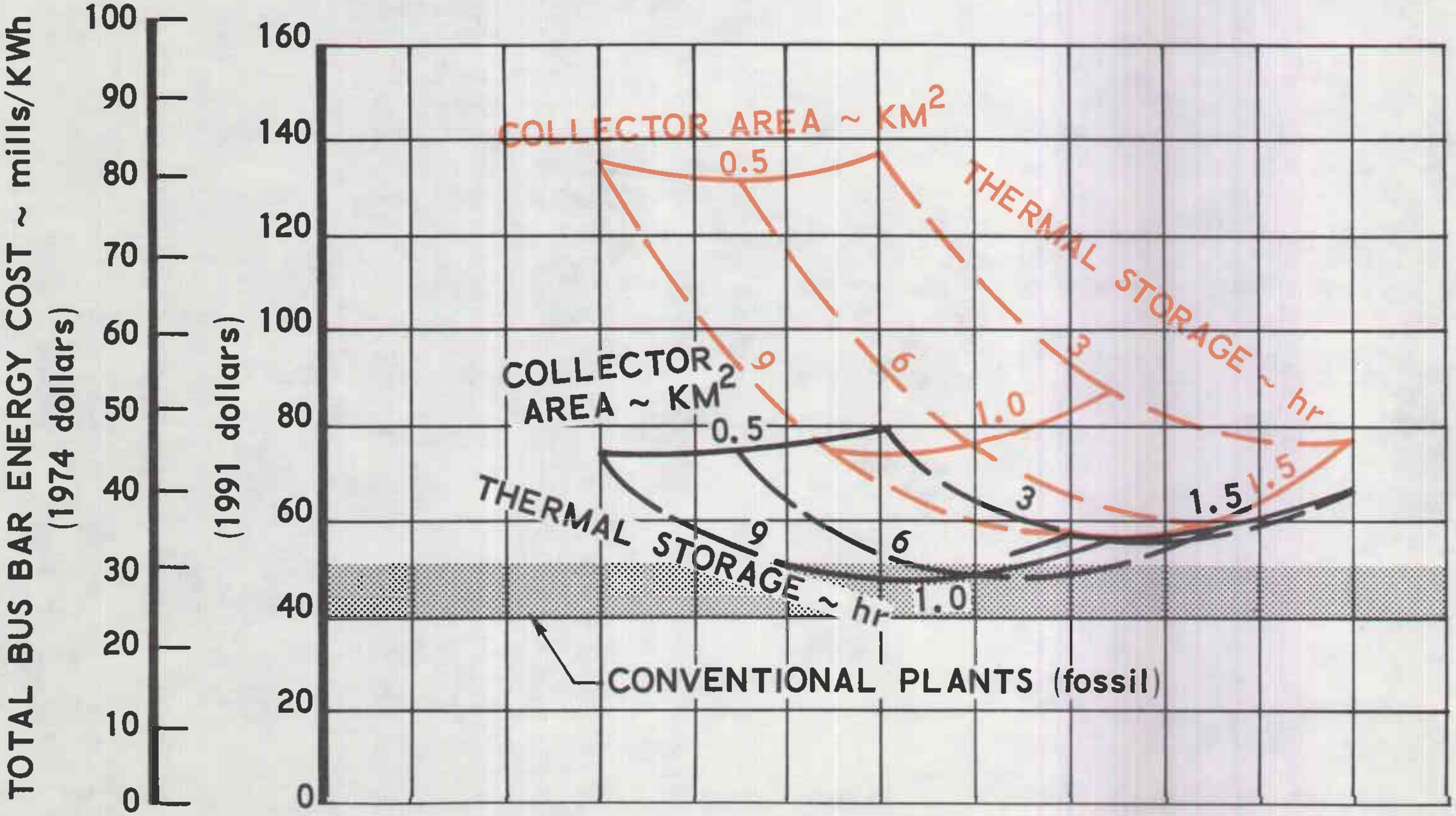
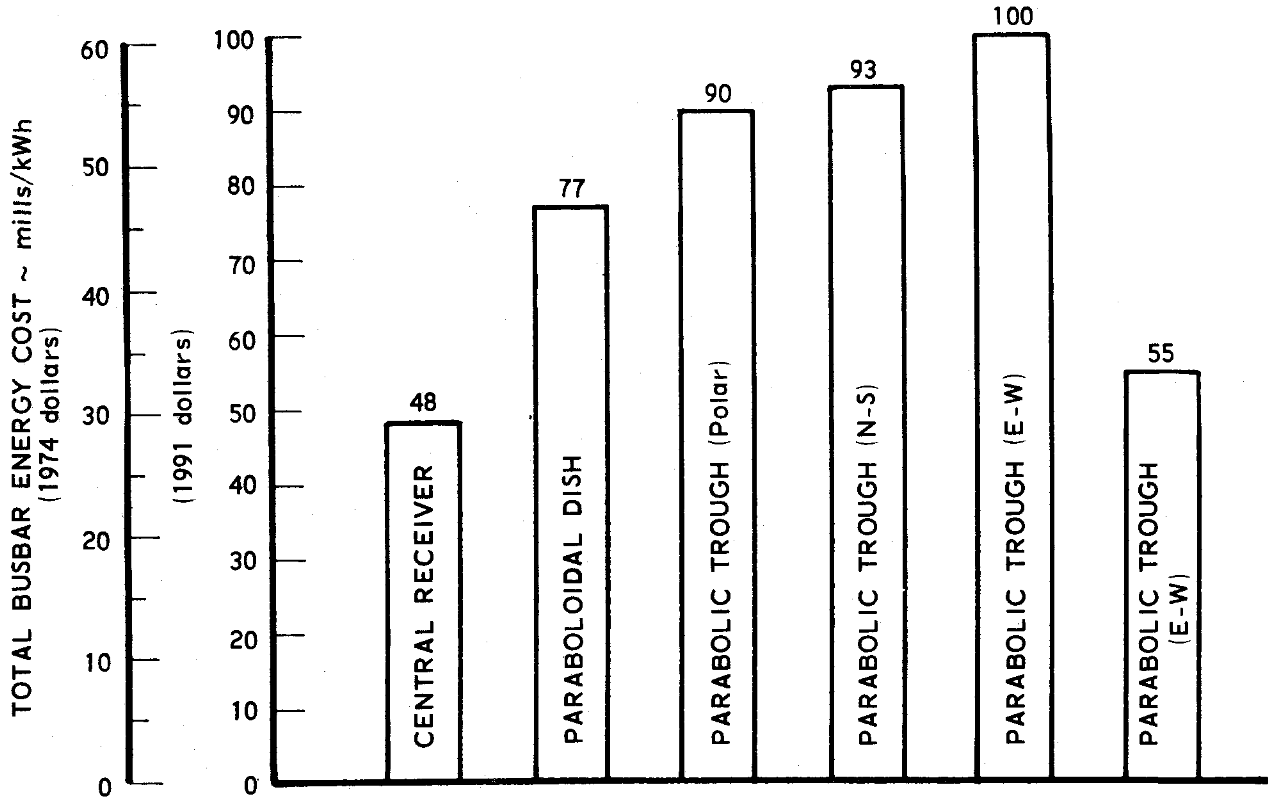


Figure 4-15. Intermediate Load Central Receiver vs. Low-Cost Parabolic Trough Power Plant



COLLECTOR AREA (km^2)	1.00	1.15	1.20	1.20	1.50	1.50
COST (\$/m^2)	30	60	70	60	60	15
STORAGE CAPACITY (hr)	6	8	8	8	8	8
COST (\$/kW/hr)	15	15	15	15	15	15

Figure 4-16. Intermediate Solar Thermal Conversion Plants, Comparative Economic Evaluation

As can be seen from this economic comparison, the central receiver concept appears to be the economically preferred concept. As was shown in Figure 4-6, the busbar energy cost for this system is competitive with equivalent intermediate load convention fossil power plants, if the projected unit heliostat cost of approximately $\$30/m^2$ can be realized.

The comparative economic assessment should remain valid even though the absolute values of unit collector costs may vary, since the relative collector costs will tend to remain the same. An exception may be found for the E-W oriented parabolic trough concept if any one of the proposed low-cost collector concepts can achieve the $\$15/m^2$ cost objective, as shown by the last bar in Figure 4-16. The potential for attaining this cost objective must be verified by detailed systems analysis of the candidate concepts.

Any one of these low-cost collector concepts (if economic feasibility can be established) can be integrated into a distributed solar power plant to provide an alternative back-up candidate system to the preferred central receiver concept.

4.6.7 Intermediate Central Receiver System-Economics of Scale

The comparative economic evaluation of the alternative solar systems was performed for 100 MWe rated turbine/generator capacity power plants. These 100 MWe solar plants were compared to larger conventional power plants (1000 MWe base load and 400 MWe intermediate load). Consequently, the comparative evaluation of solar with conventional power plants is conservative, since the economics-of-scale favor the larger conventional power plants.

To assess the reduction in busbar energy cost due to economics-of-scale for solar power plants the size of the preferred central receiver solar plant, operating in the intermediate load mode, was increased in size. As will be shown subsequently (Figure 5-3), the central receiver concept envisioned may be modular with each module having a 260 meter tower and a collector area of 0.5 km^2. Consequently, two such modules would constitute a 100 MWe intermediate load central receiver power plant. The plant size can be increased by adding additional modules with a common but larger turbine/generator plant. The larger turbine/generator plant size will benefit from the associated economics-of-scale; on the other hand, increased piping costs are incurred due to connecting the additional modules to the central turbine/generator. The resulting decrease in busbar energy cost is shown in Figure 4-17 for central receiver plant ratings of 100 MWe to 500 MWe. Also shown are the corresponding number of modules required for these plant capacities.

4.6.8 Cost Sensitivity Analysis

Because of the uncertainty in cost estimates of the solar plant peculiar subsystems, as well as uncertainties in operating costs, a cost sensitivity analysis was performed. This sensitivity analysis pertains to the preferred 100 MWe central receiver system operating in the intermediate mode.

The impact on the busbar energy cost due to changes in the following major subsystem and operating cost estimates was examined in this analysis:

- Heliostat unit collector cost
- Thermal storage cost
- Operating and maintenance costs
- Conventional backup capacity cost

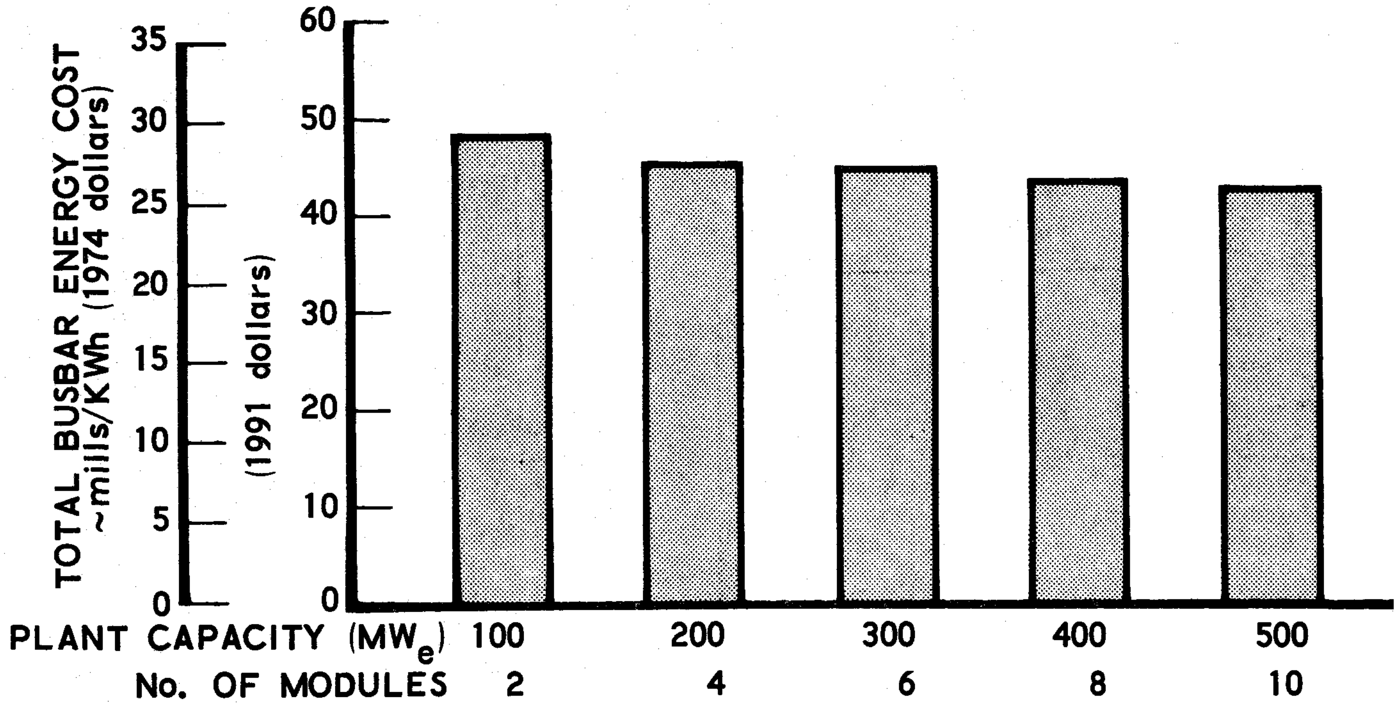


Figure 4-17. Intermediate Central Receiver System, Economics of Scale (Modular Concept)

The cost sensitivity results are summarized in Table 4-14. As can be seen from this table, the busbar energy cost is quite sensitive to changes in heliostat unit cost, while doubling the energy storage cost increases the busbar energy cost by only 5 percent.

This cost sensitivity analysis of major subsystem and operating cost variations is in addition to the sensitivity analysis performed in the comparative technical evaluation section (Table 2-6). This analysis assessed the impact of changes in the technical parameters on the performance and busbar energy cost for the 100 MWe intermediate load central receiver solar plant.

Table 4-14. Cost Sensitivity Analysis, Intermediate Central Receiver Plant (100 MWe)

CATEGORY	NOMINAL VALUE (1973 dollars)	CHANGE (1973 dollars)	Δ1991 BUSBAR COST MILLS/KWH (1991 dollars)	Δ1991 BUSBAR COST PERCENT
HELIOSTAT COST	$\$30/m^2$	$\pm\$10/m^2$	±7.2	±14.9%
STORAGE COST	\$15/Kwh	+\$15/Kwh	+2.5	+5.2%
OPERATING AND MAINTENANCE COSTS	$\$7.5/KW_e$	$+\$7.5/KW_e$	+5.3	+11.0%
CONVENTIONAL BACKUP CAPACITY REQUIRED	0.0 MWe	+20 MWe	+6.6	+13.7%

5. PREFERRED SYSTEM SELECTION/DEFINITION

From the results of the comparative technical and economic evaluation of the alternative solar thermal conversion concepts a preliminary system selection and definition can be made. The identification of preferred systems is one of the objectives of the solar thermal conversion mission analysis.

5.1 PREFERRED SYSTEM SELECTION/DEFINITION

The criteria for the selection of the preferred solar systems are long-term economic viability, technical feasibility and development risk. These criteria were addressed in the technical and economic evaluation of the alternative solar thermal conversion concepts discussed in the previous sections.

The preferred solar thermal conversion systems identified for providing electric power and their associated system definition are summarized in Figure 5-1. The selection and definition of the preferred solar power plant systems are based upon the results of the comparative technical and economic evaluation of the alternative solar thermal conversion concepts for electric power application in realistic operating environments. The input data to these analyses reflect the various system contractor technical and cost inputs. When additional data become available, these will be incorporated in future assessment of these systems.

The primary preferred system identified is the intermediate load stand-alone central receiver power plant. As will be discussed subsequently (Figures 5-2 through 5-4), a modular concept for this system appears desirable, thereby limiting the tower height to less than 300 m. As shown in Figure 4-16, this system, with a collector area of 1 km^2 and thermal storage capacity of 6 hours per 100 MWe rated plant capacity,

- CRITERIA
  - LONG-TERM ECONOMIC VIABILITY ~ 40-50 mills/kWh (1991 dollars)
  - TECHNICAL FEASIBILITY
  - DEVELOPMENT RISK
- PREFERRED SYSTEMS
  - PRIMARY SYSTEM
    - INTERMEDIATE CENTRAL RECEIVER POWER PLANT
      - MODULAR CONCEPT ~ 50 MW_e/MODULE
      - COLLECTOR AREA/THERMAL STORAGE ~ 1 km^2/6 hr/100 MW_e
      - TOWER HEIGHT ~ 260 m (850 ft)
      - HELIOSTAT/STORAGE COST OBJECTIVES ~ \$30/m^2; \$15/KW_e/hr
  - BACK-UP SYSTEMS
    - HYBRID INTERMEDIATE CENTRAL RECEIVER POWER PLANT
      - COLLECTOR AREA/THERMAL STORAGE ~ 0.5 km^2/0.5 hr/100 MW_e
      - TOWER HEIGHT ~ 260 m
      - HELIOSTAT/STORAGE COST OBJECTIVES ~ \$30/m^2; \$15/KW_e/hr
    - INTERMEDIATE E-W PARABOLIC TROUGH POWER PLANT
      - FIXED TROUGH/VARIABLE COLLECTOR PIPE; FRESNEL TYPE
      - COLLECTOR AREA/THERMAL STORAGE ~ 1.5 km^2/8 hr/100 MW_e
      - COLLECTOR/STORAGE COST OBJECTIVES ~ \$15/m^2; \$15/KW_e/hr
      - TECHNICAL OR ECONOMIC FEASIBILITY UNVERIFIED BY THE AEROSPACE CORPORATION

Figure 5-1. Preferred System Selection/Definition was found to result in the lowest busbar energy cost. The heliostat and thermal storage cost objectives of $\$30/m^2$ and $15/KWH(e), when realized, will meet the long-time economic viability criterion of providing electric power with a competitive busbar energy cost of 40-50 mills/KWH (1991 dollars). This concept appears to be technically feasible, although the relative development risk associated with the receiver is considered high.

Because the thermal storage subsystem design at present is not well defined, a hybrid concept central receiver power plant with limited storage (~0.5 hr) operating in the intermediate load mode has been identified as a back-up system (See Figure 4-10). Since a conventional fossil fuel boiler replaces the long-term thermal storage subsystem, the collector area required per 100 MWe rated plant capacity is limited to $0.5\ km^2$ (1 module). Otherwise, the same system definition and cost objectives as defined above for the stand-alone central receiver power plant apply.

As discussed in the preceding sections, a low-cost ($\$15/m^2$) E-W oriented parabolic trough collector, such as the fixed collector/variable receiver, Winston-type, or segmented (Fresnel) collector concept, if attainable, may result in an economically attractive back-up distributed system. The technical or economic feasibility of any of these latter concepts has not been verified since at present no detailed systems studies results are available for these concepts.

5.2 CENTRAL RECEIVER CONCEPT - GEOMETRIC RELATIONSHIPS

The relative geometric relationships were maintained throughout the parametric analysis of the central receiver concept to maintain identical technical characterization for consistent comparative evaluation.

These geometric relationships for the central receiver concept are shown in Figure 5-2. Presented are the height and number of towers and the

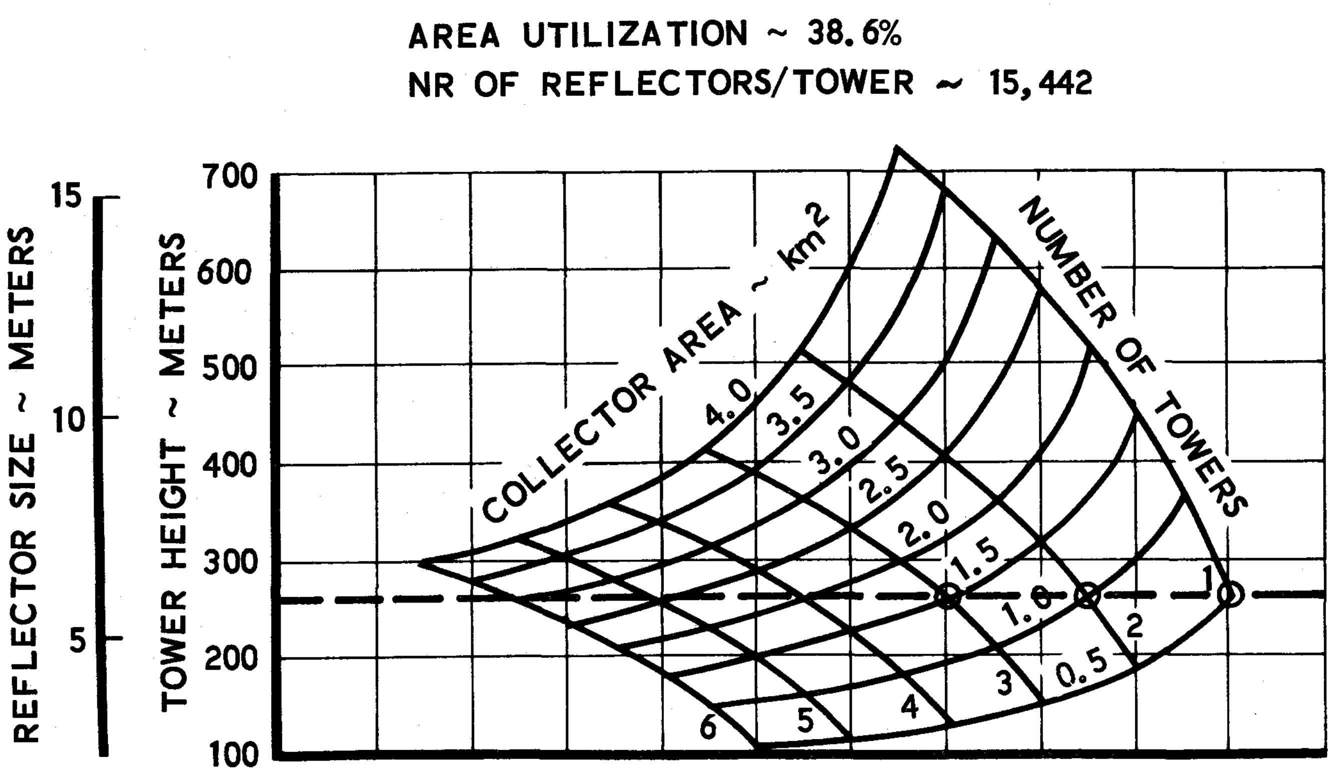


Figure 5-2. Solar Thermal Conversion Power Plant, Central Receiver Concept

size of heliostats for different collector areas. The area utilization of 38.6% and size and number of reflectors per tower reflect a winter-perturbed central receiver configuration based upon system design data obtained from the University of Houston/McDonnell-Douglas study team.

As was determined in the preceding technical evaluation of the stand-alone central receiver concept, the collector area required per 100 MWe rated plant capacity is 1.5 km^2, 1.0 km^2, and 0.5 km^2 for base load, intermediate, and peaking operation, respectively. For a 100 MWe hybrid central receiver plant, the required collector area is 0.5 km^2.

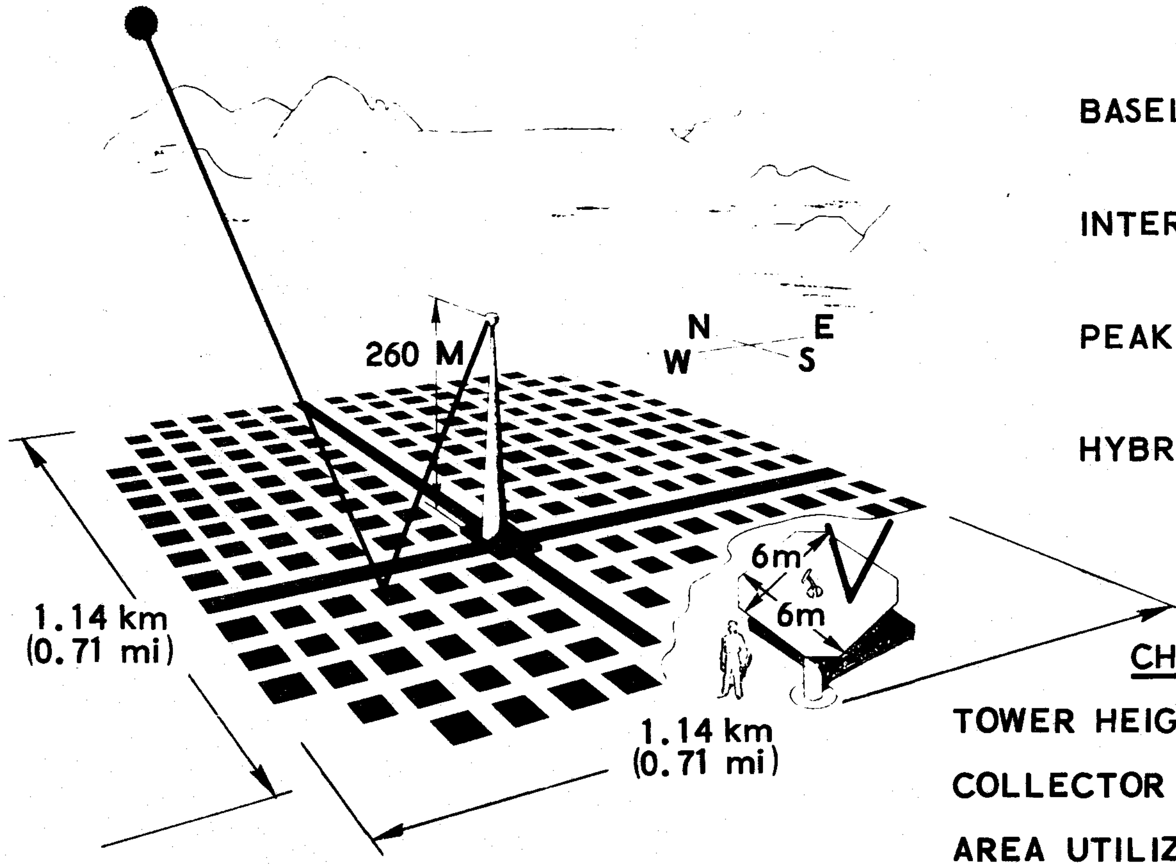
As can be seen from Figure 5-2, a 1.5 km^2 collector area with a single tower requires a tower height of 450 m and heliostat size of 10 x 10 m, while a three-tower configuration, each with a 0.5 km^2 collector area, reduces the individual tower height to 260 m with an associated heliostat size of 6 x 6 m.

Consequently, as shown on this figure, central receiver modules with a tower height of approximately 260 m and a collector area of 0.5 km^2 can be combined so that 3, 2, and 1 modules constitute a 100 MWe base load, intermediate and peaking, or hybrid plant, respectively.

5.3 CENTRAL RECEIVER POWER PLANT

In the figure 5-2 it was shown that a modular central receiver system consisting of a collector area of 0.5 km^2 per module with a tower height of approximately 260 m can be combined so that 3, 2, and 1 modules comprise a 100 MWe base load, intermediate, and peaking or hybrid plant, respectively.

Typical geometric characteristics of such a central receiver module are shown in Figure 5-3. As can be seen, with an area utilization of 38.6 percent, the total land area required per module is approximately 0.5 mi^2 (1.3 km^2).



100 MW_e PLANT

BASELOAD	3 MODULES (12 hr storage)
INTERMEDIATE	2 MODULES (6 hr storage)
PEAKING	1 MODULE (3 hr storage)
HYBRID	1 MODULE (1/2 hr storage)

CHARACTERISTICS

TOWER HEIGHT	260 m
COLLECTOR AREA	0.5 km^2/MODULE
AREA UTILIZATION	38.6%
TOTAL LAND AREA	1.3 km^2/MODULE
No. OF COLLECTORS	15,400/MODULE
SIZE OF COLLECTORS	32.4 m^2

Figure 5-3. Solar Thermal Conversion, Central Receiver Concept

5.4 CENTRAL RECEIVER MODULAR CONCEPT

A modular approach for central receiver power plants appears very attractive at this time. The advantages and disadvantages of the modular approach are summarized in Figure 5-4. As was shown in the previous figures, the individual modules can be combined to comprise either base load, intermediate, peaking or hybrid plants.

Limiting the tower height to 260 m appears better suited from seismic and aesthetic considerations than the taller towers required in the non-modular approach. Furthermore, the modular approach offers maximum flexibility in plant size, development and construction, as well as standardization of major subsystems. A disadvantage arises due to the additional piping costs of connecting the various modules to a common turbine/ generator plant.

ADVANTAGES

- MODE OF OPERATION
  - BASE-LOAD (3 modules/100 MW_e)
  - INTERMEDIATE (2 modules/100 MW_e)
  - PEAKING (1 module/100 MW_e)
  - HYBRID (1 module/100 MW_e)
- LIMITED TOWER HEIGHT
  - 260 m (850 ft) (SEISMIC, ENVIRONMENTAL)
- FLEXIBILITY
  - SIZE OF POWER PLANT
  - STANDARDIZATION (TOWER, HELIOSTATS)
  - SITING (1.3 km^2 (0.5 mi^2)/module)
  - CONSTRUCTION
  - PROXIMITY TO LOAD CENTERS
  - TESTING/DEVELOPMENT (FULL SCALE COMPONENTS)
  - TOTAL ENERGY SYSTEMS APPLICATION
- MINIMUM DEVELOPMENT RISK
  - COMMERCIAL PLANT, DEMONSTRATION, PROOF-OF-CONCEPT
- IMPROVED RELIABILITY OF OPERATION

DISADVANTAGES

- INTERCONNECTION/PIPES
- ECONOMIES OF SCALE

Figure 5-4. Central Receiver Modular Concept

6. ENVIRONMENTAL IMPACT/MARKET CAPTURE POTENTIAL

In addition to the technical, economic, and siting comparative assessment of solar thermal conversion applications, the relative environmental characteristics of alternative power plants are an important issue. This environmental impact issue was addressed in a preliminary fashion. Furthermore, for the preferred solar thermal conversion system identified, a preliminary analysis of the market capture potential was made, as described in this section.

6.1 ELECTRIC POWER PLANNING MODEL/ ENVIRONMENTAL IMPACT

The environmental impact of solar power plants is an important factor in determining the potential of such plants for electric power generation.

The comparative environmental impact of solar versus conventional plants can be evaluated with the electric power planning model shown schematically in Figure 6-1. The model treats two separate types of issues: those related to growth in the generation system of a utility over a period of years and those related to the operating consequences of a fixed generation system over the course of a single year. As indicated in Figure 6-1, the principal issues of the first type include resources, industrial capacity, manpower availability and economic (capital) resources. This part of the model is now being completed and will be used to examine the growth in land and capital requirements as a utility system expands with and without solar power plants. Investment capital is recognized as a major current problem for the utility industry which may be aggravated by the construction of capital intensive solar power plants even though substantial fuel savings would be achieved.

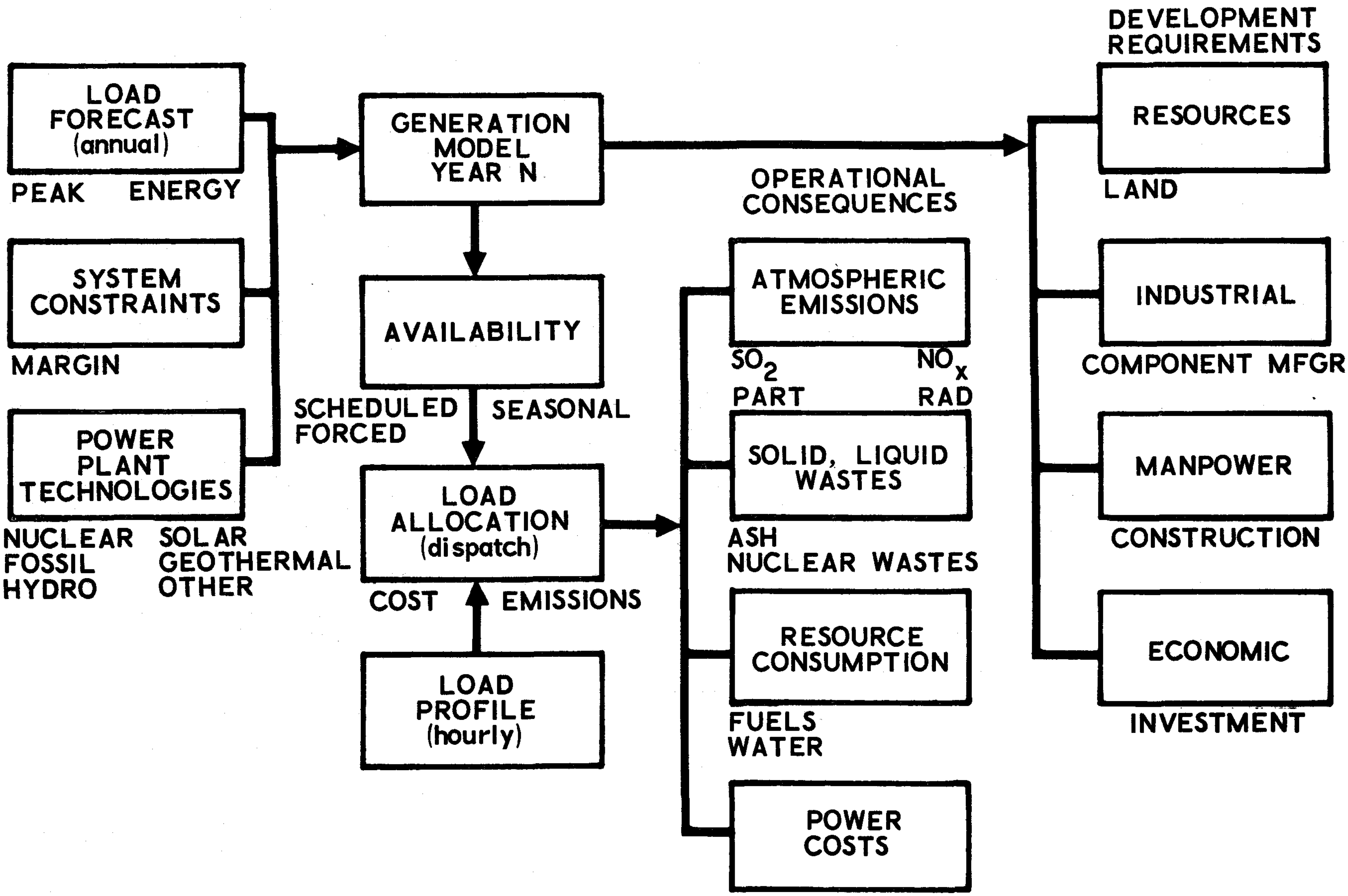


Figure 6-1. Electric Power Planning Model

The model presently is capable of defining the wastes produced, effluents released, resources consumed, and total power costs of a given utility system over a full year of operation. The model provides for scheduled maintenance and optimizes the dispatch of individual power plants to satisfy the total system demand consistent with minimum fuel costs, atmospheric effluents (e.g., as in Los Angeles) or any other operating strategy that can be quantitatively defined. A key subsystem in the logic of the model is the dispatch subroutine which properly selects from the total available capacity only those power plants required to satisfy the total system demand consistent with imposed operating and margin constraints. This subroutine has been developed specifically to assess solar power plants and consequently incorporates information on the availability of insolation and energy storage requirements. Parametric calculations using this model will be performed in subsequent studies.

6.2 MARKET CAPTURE POTENTIAL

A preliminary assessment of the market capture potential has been made for the preferred intermediate load central receiver system described in the previous section. This central receiver concept has the potential of long-term economic viability as compared to conventional plants for intermediate load application (40-50 mills/KWH, 1991 dollars).

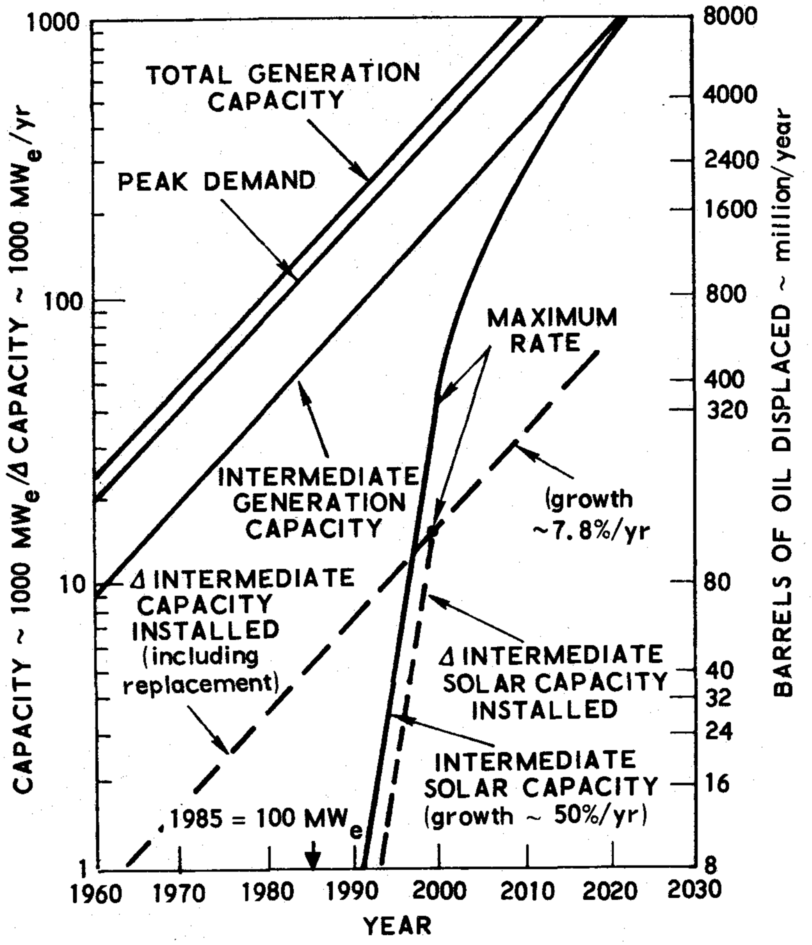
With the demonstration of long-term economic viability and technical feasibility the potential market for solar thermal conversion power plants for the Southwestern United States can be assessed. Factors contributing to this potential market that must be considered include the projected growth in installed generation capacity, the allocation of the load by operational mode (base, intermediate, peaking), manufacturing rate capabilities, construction lead times, siting constraints, relative economics, environmental factors, and conventional fuel availability.

Based upon the peak demand load forecast for the Southwestern United States and reasonable margin requirements, the total projected generation capacity can be determined, as shown in Figure 6-2. From analysis of the load duration curve, the intermediate load generation capacity forecast can be derived. The intermediate load generation capacity that must be installed each year to meet the forecasted total installed capacity, as well as for replacement of retired power plants, is also shown in this chart. This newly installed intermediate capacity per year constitutes the maximum construction rate for intermediate mode solar power plants.

Assuming commercial demonstration of a 100 MWe central receiver plant by 1985 and a 50 percent growth rate in construction subsequently, results in a total installed solar thermal electric power plant capacity of 40,000 MWe by the year 2000 and a corresponding fossil fuel displacement of approximately 320 million barrels of oil per year.

After the year 2000 the maximum growth rate in new intermediate load solar power plant construction is constrained to the maximum growth rate of 7.8 percent per year. The total installed intermediate load solar plant capacity can reach 100 percent of the intermediate capacity by the year 2030.

The siting analysis for the Southwestern United States under the most stringent criteria identified approximately 21,500 sq. mi. of potentially suitable land area, which corresponds to 2,150,000 MWe of intermediate load central receiver capacity. Consequently, the siting of these solar power plants does not appear to impose a constraint on the market capture potential. Cooling water availability in the Colorado River Basin siting area, however, may be limited to support approximately 60,000 MWe of generating capacity, assuming wet cooling towers. Consequently, for conservatism the technical and economic evaluation assumed the use of dry cooling towers.



- PLANT TYPE:
  - CENTRAL RECEIVER
  - HELIOSTAT AREA/STORAGE ~ 1 km^2/6 hr
  - INTERMEDIATE MODE
- RELATIVE ECONOMICS:
  - TOTAL BUSBAR COST (1991 dollars)
    - SOLAR ~48 mills/kWh
    - CONVENTIONAL ~ 40-50 mills/kWh
- CAPACITY/FUEL DISPLACEMENT

YEAR	MW$_e$	INT. CAP. DISPL. (%)	BBLS OIL (million/yr)	LAND (sq mi)
1985	100	0.17	0.8	1
1990	700	0.85	5.6	7
1995	5400	4.32	43.2	54
2000	40,000	21.83	320.0	400
2005	145,000	50.00	1160.0	1450

- SITING CONSTRAINT
  - SUITABLE AREA (SW US) ~ 21,500 sq mi
  - COOLING WATER
- ENVIRONMENTAL IMPACT
  - LAND USE (1 sq mi/100 MW$_e$)
  - NO POLLUTANTS
  - AESTHETIC
- INSTITUTIONAL
  - HIGH CAPITAL INVESTMENT COST
    - SOLAR $1360/KW$_e$
    - CONVENTIONAL $343/KW$_e$

Figure 6-2. Market Capture Potential, Intermediate Solar Thermal Conversion Plant

7. SUMMARY/CONCLUSIONS

The mission analysis efforts to date have successfully consolidated the diverse solar thermal conversion system, subsystem, and component contractor studies for electric power applications. These activities and conclusions can be summarized as follows:

- o A number of basic computer methodologies have been developed to assess the potential of solar thermal conversion missions and systems in realistic operating environments. These methodologies were applied on a consistent basis to assess the alternative system concepts for electric power application in the Southwestern United States.

- o An insolation climatology data base for 20 weather stations representative of the various climatic regions of the Southwestern United States has been developed. Also, a 'worst-case' data base was developed for two locations. These standard data bases are available to NSF contractors.

- o Hourly demand projections for the 1980 to 2000 time period of the major Southwestern United States electric utility companies were generated using the electric power demand forecast methodology developed. These data are also available to other NSF contractors.

- o The generating capacity displacement potential of solar power plants operating in a total utility grid with conventional power plants was assessed in the margin analysis.

- o A comparative technical and economic evaluation was made of the alternative solar power concepts and modes of operation (i.e., base load, intermediate, or peaking). These assessments were made on a consistent basis using the detailed system simulation and economic methodologies developed, and incorporating the combined technical and cost information obtained from the other NSF system contractors.

- Based upon the results of the comparative evaluation a preliminary selection and definition of a preferred system concept was made. The primary preferred concept identified is a stand-alone central receiver power plant. The back-up systems identified are a hybrid central receiver power plant, and a potentially low-cost E-W parabolic trough distributed system. The technical and economic potential of this latter concept has not been verified by detailed system studies. For each of these systems the intermediate or load-following mode of operation was identified as being economically most competitive with a 1991 busbar energy cost of 25-30 mills/KWH (1974 dollars).

- The siting analysis performed for the Southwestern United States has under the most stringent criteria identified a potentially suitable land area of 21,500 sq. mi. Consequently, siting does not appear to impose a constraint on the potential of these solar power plants. However, the water resources in this area were found to be limited which may eventually require the use of dry cooling towers.

- For the preferred intermediate load central power plants, a preliminary market capture potential of 40,000 MWe (cummulative) was projected for the Southwestern United States by the year 2000.

- The above market potential of 40,000 MWe by the year 2000, if realized, would result in a fossil fuel savings of approximately 320 million barrels of oil per year. No major environmental impact of these solar power plants was identified, other than the waste-heat disposal problem common to all electric power plants. Furthermore, no unusual critical materials have been identified that are necessary for the preferred central receiver system. The major barrier to implementation is expected to be the high initial capital investment projected for the solar power plants.

These conclusions are based upon the latest available data. However, subsequent analyses will incorporate new data as these become available. Subsequent studies will also address the total energy concept on a consistent basis using the various methodologies developed.

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APPENDIX A
PARABOLIC CYLINDER SYSTEM TRACKING GEOMETRY

The tracking efficiency relationships for optimal performance were developed from geometrical relations between the collector and solar orientations. In each of the three parabolic cylindrical collector orientation models, an expression was obtained for the angle between the direction of the collector normal and the line of sight to the sun. This was differentiated with respect to the angle that varies with the movement of the collector in attempting to track the sun, and then set to zero to find the minimum.

The basic equations representing this approach were developed from the vector representation depicted in Figure A-1. The following vector expressions apply.

$$\overline{S} = x_s\hat{i} + y_s\hat{j} + z_s\hat{k}$$

$$\overline{N} = x_n\hat{i} + y_n\hat{j} + z_n\hat{k}$$

where the subscripts s and n refer to the sun and collector normal, respectively.

$$\overline{S} \cdot \overline{N} = \cos\theta = x_s x_n + y_s y_n + z_s z_n$$

where θ is to be minimized.

The following nomenclature defines the solar and collector orientations:

α_s = azimuth of the sun (measured from south; + to west; - to east)

β_s = elevation of sun

α_n = azimuth of the collector normal (same convention)

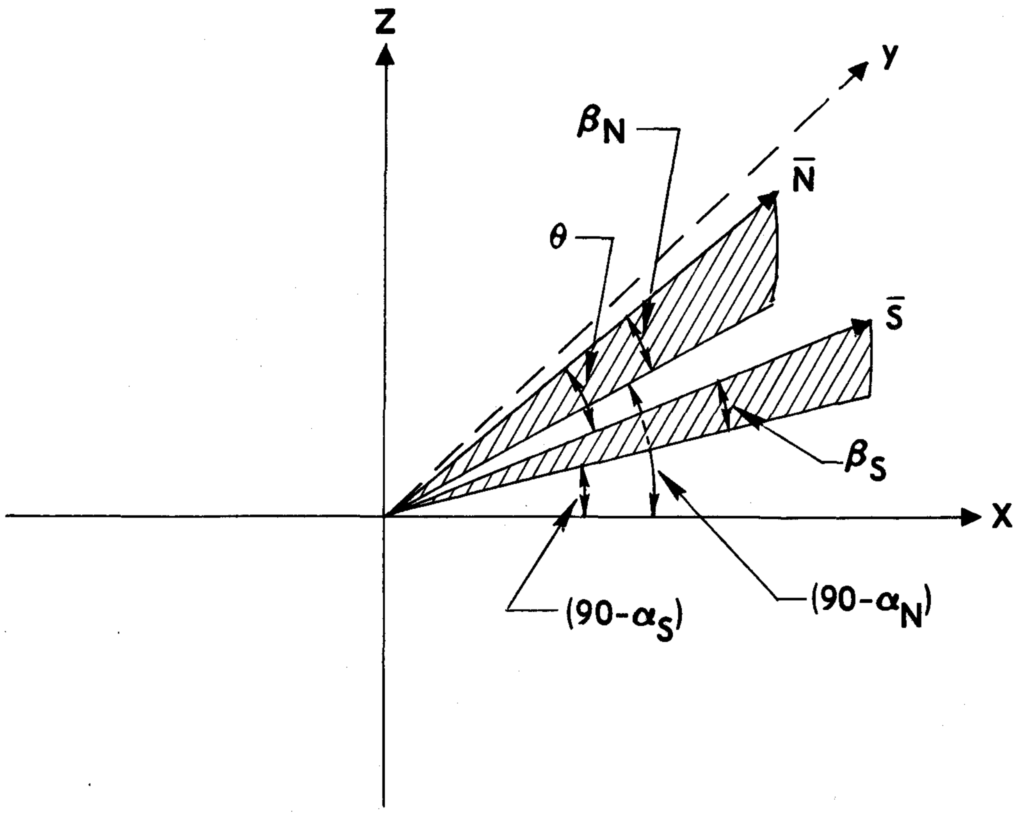

Figure A-1. Basic Vectorial Representation for Determination of the Angle

β_n = elevation of collector normal

Since: $x_s = \cos \beta_s \sin \alpha_s$

$y_s = \cos \beta_s \cos \alpha_s$

$z_s = \sin \beta_s$

And: $x_n = \cos \beta_n \sin \alpha_n$

$y_n = \cos \beta_n \cos \alpha_n$

$z_n = \sin \beta_n$

Therefore: $\cos \theta = \cos \beta_s \cos \beta_n (\sin \alpha_s \sin \alpha_n + \cos \alpha_s \cos \alpha_n) + \sin \beta_s \sin \beta_n$

$$\cos \theta = \cos \beta_s \cos \beta_n \cos (\alpha_s - \alpha_n) + \sin \beta_s \sin \beta_n \quad \text{(A-1)}$$

This equation takes on the following forms for the three collector orientation models.

(1) E-W parabolic collector; $\alpha_n = 0$

$$\cos \theta = \cos \beta_s \cos \beta_n \cos \alpha_s + \sin \beta_s \sin \beta_n$$

(2) N-S parabolic collector; $\alpha_n = 90^\circ$

$$\cos \theta = \cos \beta_s \cos \beta_n \sin \alpha_s + \sin \beta_s \sin \beta_n \quad \text{(A-2)}$$

(3) Polar parabolic collector

$$\cos \theta = \cos \beta_s \cos \beta_n \cos (\alpha_s - \alpha_n) + \sin \beta_s \sin \beta_n \quad \text{(A-3)}$$

The pertinent geometrical angles for the E-W parabolic collector are shown in Figure A-2. From the labeled spherical trangle, or equation (A-1), it is evident that:

$$\cos \theta = \sin \beta_s \sin \beta_n + \cos \beta_s \cos \beta_n \cos \alpha_s$$

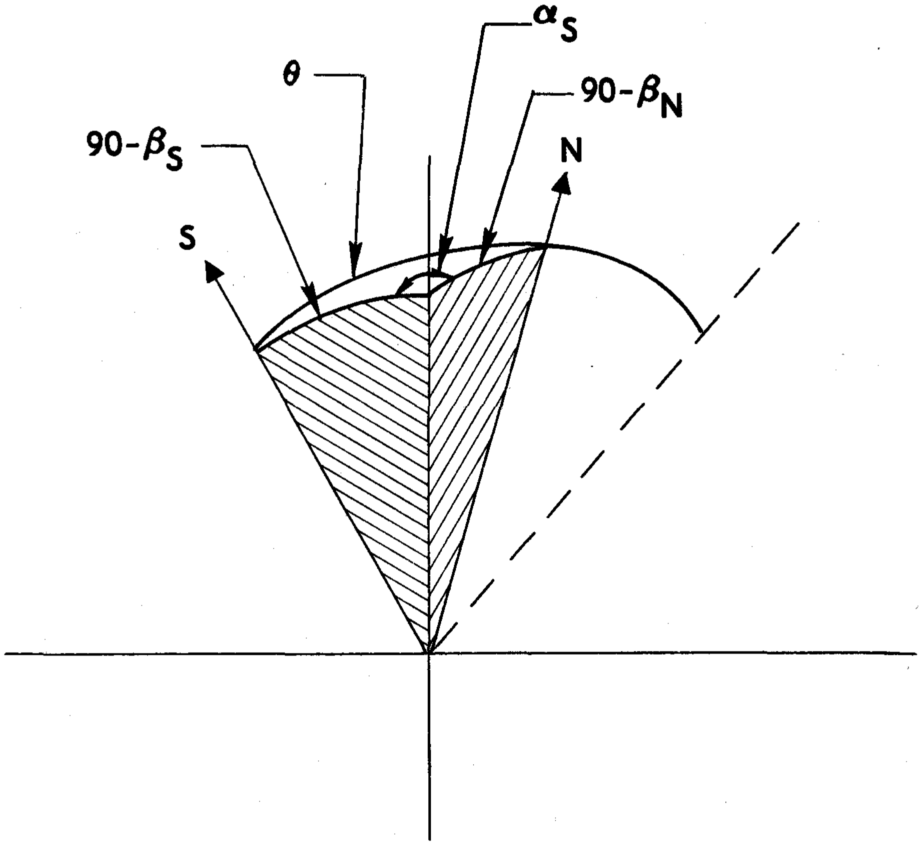

Figure A-2. Geometrical Angles for E-W Parabolic Trough Collector

Differentiating with respect to β_n, yields:

$$-\sin\theta \frac{\partial\theta}{\partial\beta_n} = \sin\beta_s \cos\beta_n - \cos\beta_s \sin\beta_n \cos\alpha_s$$

Setting this expression to zero, the resulting criteria for optimum tracking is:

$$\tan\beta_n = \tan\beta_s / \cos\alpha_s \tag{A-4}$$

$\cos\theta$ can then be obtained from equation (A-1) for the E-W parabolic collector.

Figure A-3 illustrates the geometry for the N-S parabolic collector orientation model. Equation (A-2) can be derived from the spherical triangle. Differentiating with respect to β_n, yields:

$$-\sin\theta \frac{\partial\theta}{\partial\beta_n} = -\sin\beta_n \cos\beta_s \sin\alpha_s + \sin\beta_s \cos\beta_n$$

Setting this expression to zero results in the expression for optimum tracking:

$$\tan\beta_n = \tan\beta_s / \sin\alpha_s \tag{A-5}$$

This may then be used with equation (A-2) to calculate $\cos\theta$ for the N-S parabolic collector.

The angular quantities for the polar parabolic collector are shown in Figure A-4. From the spherical triangles involved, it is evident that:

$$\cos c = \sin\beta_s \cos TC + \cos\beta_s \sin TC \cos\alpha_s$$

Also

$$\frac{\sin a'}{\cos\beta_s} = \frac{\sin\alpha_s}{\sin c} \quad \text{and } E = a' - 90^\circ$$

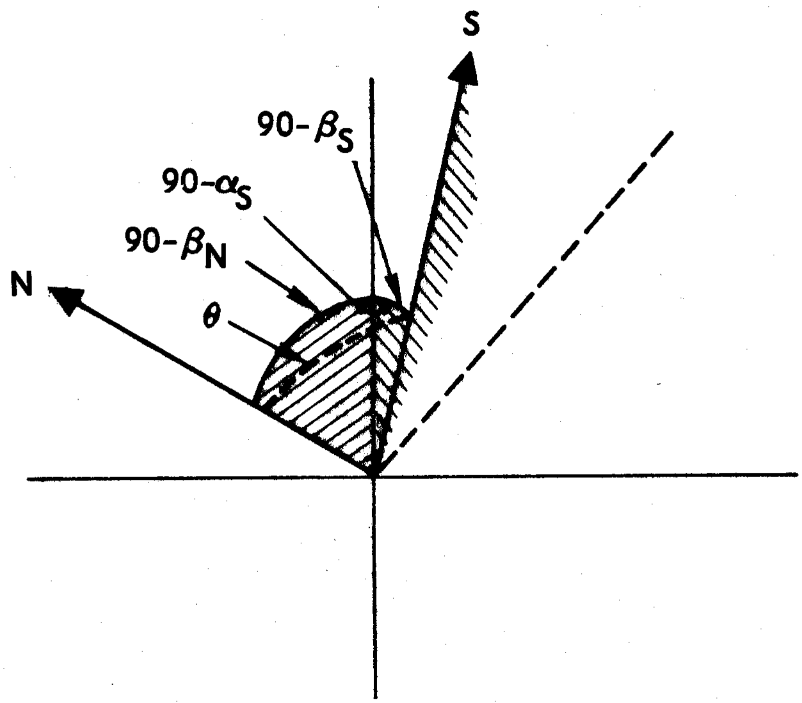

Figure A-3. Geometrical Angles for N-S Parabolic Trough Collector

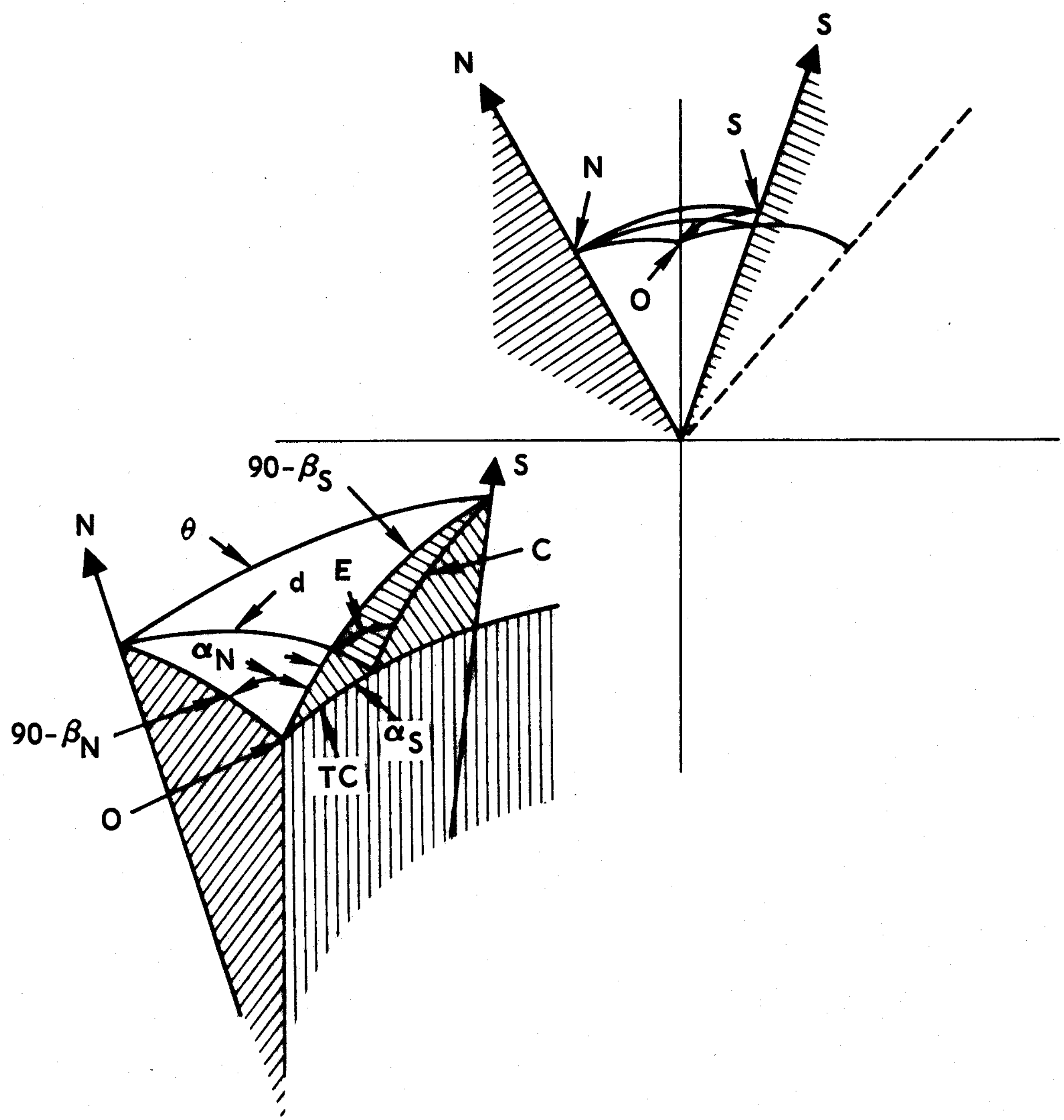

Figure A-4. Geometrical Angles for Polar Parabolic Trough Collector

Now

$$\cos \theta = \cos d \cos c + \sin d \sin c \cos E$$

$$= \cos d \cos c + \sin d \sin c \sin a'$$

$$= \cos d \cos c + \sin d \sin \alpha_s \cos \beta_s$$

$$= \cos d \left[\sin \beta_s \cos TC + \cos \beta_s \sin TC \cos \alpha_s\right] + \sin d \sin \alpha_s \cos \beta_s$$

In this case the angle is optimized by differentiating with respect to d:

$$- \sin \theta \frac{\partial \theta}{\partial d} = - \sin d \left[\sin \beta_s \cos TC + \cos \beta_s \sin TC \cos \alpha_s\right]$$

$$+ \cos d \sin \alpha_s \cos \beta_s$$

Setting this expression to zero, yields:

$$\tan d = \frac{\sin \alpha_s \cos \beta_s}{\sin \beta_s \cos TC + \cos \beta_s \sin TC \cos \alpha_s} \tag{A-6}$$

for optimum tracking.

From Figure A-4, the following relations are also evident.

$$\sin \beta_n = \cos d \cos TC \tag{A-7}$$

$$\sin \alpha_n = \sin d / \cos \beta_n \tag{A-8}$$

These quantities may be used in equation (A-3) to obtain $\cos \theta$ for the polar collector

APPENDIX B

ALGORITHM TO COMPUTE AN APPROXIMATE CAPACITY PROBABILITY DISTRIBUTION

The capacity x_{ij} of the i^{th} power plant has associated with it a probability of occurrence P_{ij} where j is an index over the possible <u>discrete</u> values of capacity for the plant. At any time some value of capacity, possibly zero, occurs so that we have:

$$\sum_{j=1}^{m_i} P_{ij} = 1 \tag{B-1}$$

where m_i is the number of states or capacity values possible for the i^{th} plant.

The generating function for the states of the grid (referred to as the "generation model" in the main text of this report) of n plants is given by:

$$\left(\sum_{j=1}^{m_1} P_{ij}\right)\left(\sum_{j=1}^{m_2} P_{2j}\right) \cdot \cdot \cdot \left(\sum_{j=1}^{m_n} P_{nj}\right) = 1 \tag{B-2}$$

The terms in the generating function (B-2) are then the possible states for the grid of n power plants. A typical term or state is given by:

$$p_{13}p_{25}p_{38}p_{41} \cdot \cdot \cdot p_{n3} \tag{B-3}$$

for which the corresponding grid capacity is:

$$x = x_{13} + x_{25} + x_{38} + x_{41} + \cdot \cdot \cdot x_{n3} \tag{B-4}$$

The number of such terms or grid states is given by:

$$m_1 m_2 m_3 m_4 \cdot \cdot \cdot m_n \tag{B-5}$$

If there are only 2 states possible for each plant equation (B-2) simplifies to:

$$(p_{11} + p_{12})\,(p_{21} + p_{22})\,(p_{31} + p_{32}) \cdot \cdot \cdot (p_{n1} + p_{n2}) = 1 \tag{B-6}$$

For this case $m_i=2$ for all $i=1, 2, \ldots n$ so that there are 2^n grid states. Even for this relatively simple case the number of possible states can be a tremendously large number so that the exact enumeration of all possible states can involve significant computer time.

In view of the above and because the current application typically involves a large number of plants it is imperative that a more efficient method be developed. Such a method, called the algorithm, is described below. The algorithm is applied to the general case, with arbitrary m_i, as shown in Eq. (B-2). The algorithm assumes the x or capacity variable as being defined by discrete Δx class intervals. In the limit as Δx gets arbitrarily small the algorithm produces an exact capacity point probability distribution. However, in order to save computer time Δx is some reasonably large value such as 10-50 MWe for which the computations show that sufficient accuracy can be realized.

The algorithm is based on the following computational procedure. The index of the n plants is denoted by i. The method does not depend on any ordering of the n plants. The capacities for the first plant (i=1) are mapped into the k Δx class intervals where $k = 1, 2, 3, \ldots$. The value of zero capacity is mapped into the first class inverval $[0, \Delta x]$. The first class inverval is inclusive of zero as well as the upper limit Δx. From then on the k^{th} class interval is $[(k-1)\Delta x, k\Delta x]$ or inclusive of the upper limit $k\Delta x$ but not of the lower limit. In essence then the point probabilities p_{1j}, $j=1, 2, \ldots m_1$, are associated with the midpoints of their respective class intervals. Assuming this modified probability distribution A_{1k} (defined at equal intervals of Δx), plant No. 2 is now "combined" with A_{1k} to obtain the combined probability distribution A_{2k} similarly defined over the class intervals $k\Delta x$, $k=1, 2, 3, \ldots$. Table B-1 illustrates the computations involved. The integral multiples of Δx is the key index variable in the computations. This index is defined by $\left\{\frac{x_{ij}}{\Delta x}\right\} + 1$ for the first plant (i=1) and by $\left\{(x_{ij} + \frac{\Delta x}{2})/\Delta x\right\}$ for $i \geq 2$. The brackets $\{\ \}$ denotes that the number in the brackets is defined as an integer less than or equal to that number. Thus, we note that zero capacity has associated with it the index "1" in initializing the first plant where the midpoint value for this first interval is $\Delta x/2$. All values up to (and inclusive of) Δx are assigned the value $\Delta x/2$. In processing the successive plants, however, values up to (and exclusive of) $\Delta x/2$ have an index of "0" meaning that $0(\Delta x) = 0$ incremented in this case, and $1\ (\Delta x)$ is incremented for values of x in the interval $\left[\frac{1}{2}\Delta x,\ \frac{3}{2}\Delta x\right]$.

After the processing of the $(i-1)^{st}$ plant the k^{th} class interval in the processing of the i^{th} plant has the probability:

$$P_{ik} = \sum_{\ell} p_{i\ell}\ A_{(i-1)\ (k-\ell)} \tag{B-7}$$

The sum in (B-7) is over all values of ℓ such that the indices ℓ and $(k-\ell)$ add up to k. In the computer program this computation is performed only for non-zero values of the probability elements.

The computations shown in Table B-1 for i = 1 and 2 applies to any stage, each stage processing one more plant. The algorithm computations are completed when the n^{th} plant is processed with the output A_{nk} associated with the capacity midpoint value $k\Delta x - \Delta x/2$. Thus the minimum value is the midpoint of the first interval $\Delta x/2$ (for k=1) and the maximum value is the midpoint of the last interval $n\Delta x - \Delta x/2$ (for k=n). While the point probability is associated with the midpoint of the class interval, the cumulative probability is the point probability cumulation up to and inclusive of the interval being considered and is associated with the upper limit of that class interval.

TABLE B-1

Example of Algorithm Computations

(Δx = 50 MW)

	Plant No. 1 ($m_1 = 4$)			Plant No. 2 ($m_2 = 3$)		
j	p_{1j}	x_{1j}	$\left\{\frac{x_{1j}}{\Delta x}\right\} + 1$	p_{2j}	x_{2j}	$\left\{(x_{2j} + \frac{\Delta x}{2}) / \Delta x\right\}$
1	.60	350	8	.80	175	4
2	.30	299	6	.15	124	2
3	.05	50	2	.05	0	0
4	.05	0	1			

Algorithm

k	$k\Delta x$	midpoint	A_{1k}	A_{2k}	
1	50	25	.05	$p_{20}A_{11} = (.05)(.05)$	=.0025
2	100	75	.05	$p_{20}A_{12} = (.15)(.05)$	=.0075
3	150	125	0	$p_{22}A_{11} = (.05)(.05)$	=.0025
4	200	175	0	$p_{22}A_{12} = (.15)(.05)$	=.0075
5	250	225	0	$p_{24}A_{11} = (.80)(.05)$	=.0400
6	300	275	.30	$p_{20}A_{16} + p_{24}A_{12} = (.05)(.30) + (.80)(.05)$	=.0550
7	350	325	0	0	= 0
8	400	375	.60	$p_{20}A_{18} + p_{22}A_{16} = (.05)(.60) + (.15)(.30)$	=.0750
9	450	425	0	0	= 0
10	500	475	0	$p_{24}A_{16} + p_{22}A_{18} = (.80)(.30) + (.15)(.60)$	=.3300
11	550	525	0	0	= 0
12	600	675	0	$p_{24}A_{18} = (.80)(.60)$	=.4800
			1.00		1.0000

APPENDIX C

OUTAGE BASED ON LOAD PROBABILITY DISTRIBUTION

A power capacity or supply probability distribution (capacity model in the main text) is combined with a load or demand probability distribution to obtain the probability that the load exceeds the capacity. More specifically, if y is the load in megawatts and x is the capacity in megawatts, the loss-of-load probability is given by:

$$P_o = P_r \{ y > x \} \tag{C-1}$$

This general formula applies to a wide class of problems. For example, if y and x are stress and strength variables, respectively, then P_o is the failure probability of the system being considered.

In the current application the load and capacity variables are actually stochastic processes over time. The system requirement is that the accumulated loss-of-load events over 10 years do not exceed one day (2.4 hours in one year). In order to obtain a loss-of-load evaluation the interpretation is made that the loss-of-load in terms of a proportion of time can also considered as a loss-of-load probability of discrete events. In the application, the events are defined in one hour intervals for each hour of the year. Loss-of-load in time units is simply $P_o \Delta t$, where Δt = 1 hour.

Thus the interpretation here is that loss-of-load generated by dynamic time stochastic processes can be modelled in terms of static capacity and load probability distributions to obtain a steady-state loss rate. This steady-state loss rate when summed over the period being considered then results in the total loss-of-load for the period. In view of the dynamic nature of the stochastic processes containing large diurnal variations in loads (e.g., the load for an hour at 1 a.m. is significantly less than the load for an hour at 12 noon) and large monthly variations (e.g., August tends to be a significantly higher usage month than January), the loss-of-load computed on the basis of load and capacity distributions are made by hours of the day for each month of the year. This amounts to a 12x24 (month x hour) array of loss of load computations, which when summed over the days of the month for the 12 months comprises the total loss of load for the year. If data over 10 years are available the sum over 10 years can also be computed.

The loss of load for each period is computed as follows. If g(y) is the load probability density and f(x) is the capacity probability density the loss of load probability is:

$$P_o = P_r \left\{ y > x \right\} = \int_0^\infty g(y) \int_0^y f(x)\, dx\, dy \qquad \text{(C-2)}$$

$$\text{or} = \int_0^\infty f(x) \int_0^\infty g(y)\, dy\, dx \qquad \text{(C-3)}$$

The equations above can also be written:

$$P_o = P_r \left\{ y > x \right\} = \int_0^\infty g(y)\, F(y)\, dy \qquad \text{(C-4)}$$

$$\text{or} = \int_0^\infty f(x)\, R(x)\, dx \qquad \text{(C-5)}$$

$$\text{where } F(y) = \int_0^y f(x)\, dx$$

$$R(x) = \int_x^\infty g(y)\, dy$$

In the application of the capacity density f (x) is a point probability distribution denoted by f (x_i). This point probability distribution is computed using the algorithm described in Appendix B, which assigns probabilities to discrete midpoints of intervals Δx megawatts apart. Further, the inputs to the algorithm are discrete values of individual plant capacities. The simplest case would be a two-value case, as is assumed for plant hardware failure, where a failure corresponds to zero capacity and no failure corresponds to 100 percent capacity. On the other hand, a solar plant may have additional outages due to cloud cover or limited storage capacity. These additional outages may also be assigned discrete capacity values. The discrete version of Eq. (C-5) is:

$$P_o = P_r \{y > x\} = \sum_i f(x_i)\, R(x_i) \qquad \text{(C-6)}$$

$$R(x_i) = \int_{x_i}^{\infty} g(y)\, dy$$

The sum in Eq. (C-6) is over all values of x_i. In the computer program the demand variable y can be Gaussian with mean μ and standard derivation σ. In this case the probability density is:

$$f(y) = \frac{1}{\sqrt{2\pi}\,\sigma}\, e^{-\frac{1}{2}\left(\frac{y-\mu}{\sigma}\right)^2} \qquad \text{(C-7)}$$

The integral R(y) is computed, (see Reference 22) using the transformation $y = \mu + \sqrt{2}\, z\sigma$ to obtain the correspondence between the load value y and R(y) as follows:

$$R(y) = R\,[y\,(z)] = .5 - \frac{1}{2}\,\Phi(z) \quad , \qquad z = (y-\mu)/\sqrt{2}\,\sigma \geq 0$$

$$(z) = 1 - 1 \,/\, (1 + a_1 z + a_2 z^2 + a_3 z^3 + a_4 z^4 + a_5 z^5 + a_6 z^6)^{16}$$

$a_1 = .0705\ 2307\ 84$

$a_2 = .0422\ 8201\ 23$

$a_3 = .0092\ 7052\ 72$

$a_4 = .0001\ 5201\ 43$

$a_5 = .0002\ 7656\ 72$

$a_6 = .0000\ 4306\ 38$

$$R(y) = R\;[y\,(z)] = .5 + \frac{1}{2}\,\Phi\,(|z|), \quad z < 0.$$

This computation has an accuracy to at least 6 decimals in the probability evaluation. In the computer program the computation (C-6) is done for values of $R(x_i) \geq .000004$.

APPENDIX D
DISCOUNTED CASH FLOW ECONOMIC METHODOLOGY

D.1 INTRODUCTION

The economic analysis methodology developed for conducting these assessments on a consistent basis is shown in Figure D-1. The capital investment costs for each subsystem account are estimated for a given size power plant in terms of base-year dollars. To determine the relative economics of different size power plants, an economics-of-scale subroutine has been included, consisting of cost scaling relationships.

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 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 total fixed charges. The cash flows are determined from pro forma income statements. The rate of discount is the cost of capital typical of the utility industry, which is determined by the weighted average cost of common and preferred equity and long-term debt.

The discount rate is used to calculate the present value of the future cash flows during the operating life of the plant. Estimated operating costs are combined with the total fixed charges to determine total busbar energy costs.

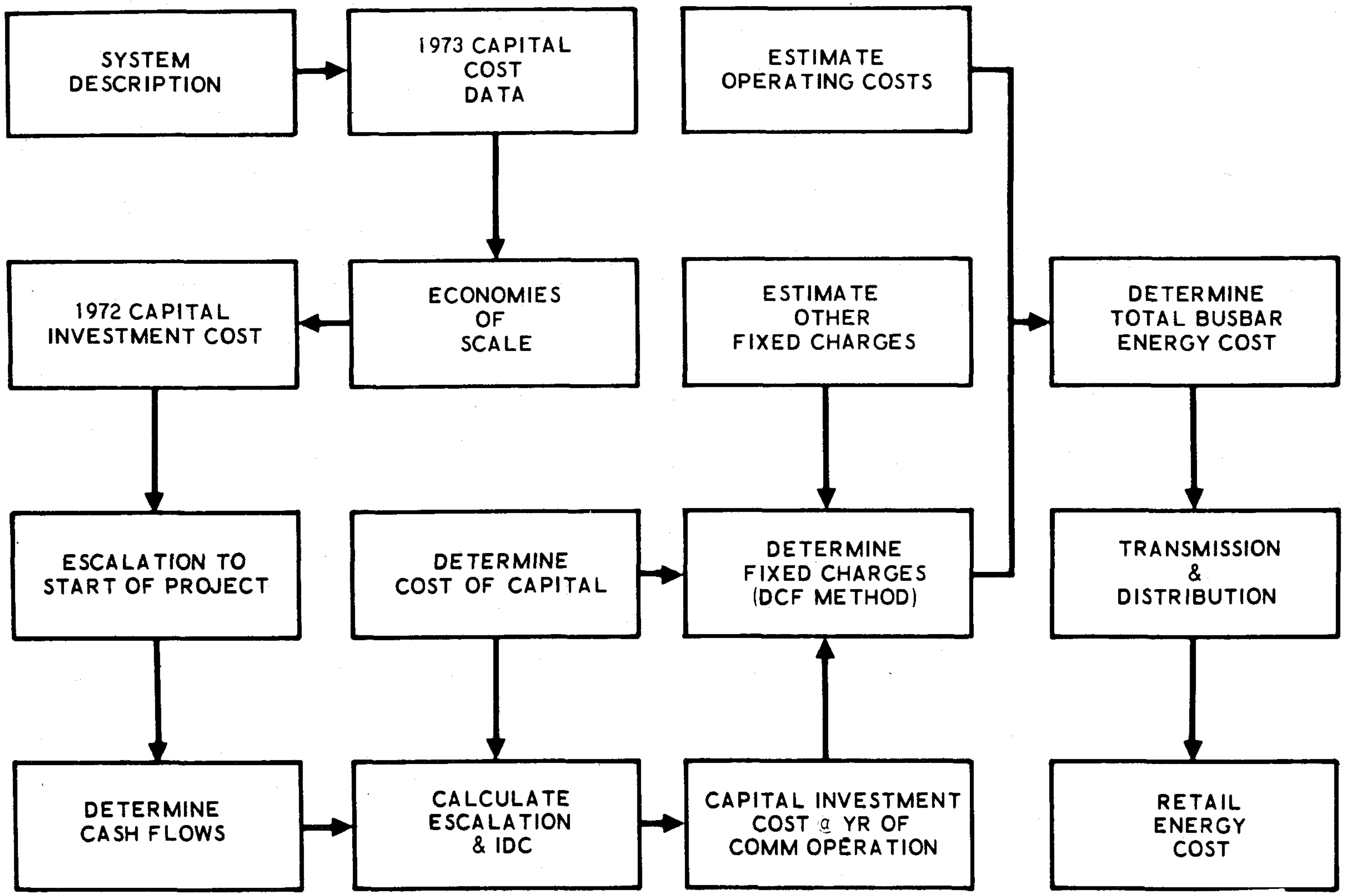

Figure D-1. Economic Analysis Methodology

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.

D.2 ECONOMICS-OF-SCALE MODEL

Scaling equations were developed for each of the investment cost accounts. These accounts are based on the summary two-digit investment accounts used by the Federal Power Commission. The scaling equations are normalized such that a 1000 MWe power plant is equal to 1.0.

The economics-of-scale model reads input values for each investment account and the associated plant size. For example, a base year cost for the turbine equipment account is input for a 1000 MWe plant. The scaling equation for this account computes the cost for the desired size plant (e.g., 1500 MWe). Thus, base year costs by investment account may be input for a single plant size and costs by investment account for different plant sizes can be determined using these scaling relationships. The resulting values for each account are summed and the base year total direct investment cost can be calculated.

The equation coefficients are shown in Table D-1 for the conventional power plant direct investment cost accounts and in Table D-2 for the indirect investment cost account ($/KWe). For each direct investment cost account, A(J) in Table D-1, the cost scaling factor (CSF) is computed as follows:

$$CSF = X(J) + X(J)\,A * MW^{X(J)\,B} \qquad \text{(D-1)}$$

where: MW is rated plant capacity in megawatts electrical and X(J), X(J) A and X(J) B are the coefficients obtained in Table 4-6 for the specific account A(J).

For the indirect investment account the equations are used to calculate the ratio (ICR) of indirect construction cost to total direct construction cost.

$$ICR = X90 + X90A * MW^{0.5} + X90B * MW^{0.25} \qquad \text{(D-2)}$$

TABLE D-1

DIRECT INVESTMENT COST SCALING EQUATIONS

		Size Range 10 MW - 500 MW		Size Range 500 MW - 2000 MW	
Account A12		Boiler Plant Equipment			
	X12	-.004		X12	.1
	X12A	.0043		X12A	.00358
	X12B	.8		X12B	.8
Account A20		Land*			
	X20			X20	.5**
	X20A			X20A	.0005
	X20B			X20B	1.0
Account A21		Structures			
	X21	0		X21	.55
	X21A	.008205		X21A	$2.839E^{-5}$
	X21B	.72		X21B	1.4
Account A22		Reactor Plant Equipment			
	No Data			X22	.25
				X22A	.0015
				X22B	.9

*Varies between conventional fossil or nuclear plants and between various designs of solar power plants. Estimate scaling equations for specific type power plant.

** Equation for conventional plants only.

TABLE D-1 (continued)

DIRECT INVESTMENT COST SCALING EQUATIONS

		Size Range 10 MW - 500 MW		Size Range 500MW - 2000 MW	
Account	A23	Turbine Plant Equipment			
	X23	-.004		X23	.195
	X23A	.00292		X23A	.0004035
	X23B	.85		X23B	1.1
Account	A24	Electrical Plant Equipment			
	X24	-.004		X24	0
	X24A	.00292		X24A	.003715
	X24B	.85		X24B	.81
Account	A26	Special Nuclear Materials			
	No Data			X26	0
				X26A	.001
				X26B	1.0

TABLE D-2

INDIRECT CONSTRUCTION COST SCALING EQUATIONS

		Size Range 10 MW - 500 MW		Size Range 500 MW - 2000 MW	
Account	A90	Indirect Construction Cost (Fossil)			
		X90F	1.0	X90F	1.0
		X90FA	.0122	X90FA	.0122
		X90FB	-.266	X90FB	-.203
Account	A90	Indirect Construction Cost (Nuclear)			
		No Data		X90N	1.56
				X90NA	.0275
				X90NB	-.308
Account	A90	Indirect Construction Cost (Solar)			
		X90S	.02	X90S	.02

No scaling equations were developed for the other direct investment cost accounts because the scaling relationships vary with the mix of subaccounts.

The scaling equations shown in Tables D-1 and D-2 apply only to conventional steam-electric power plant investment costs. They do not apply to costs for gas turbine or combined cycle plants. There are no scaling equations in the lower size range for accounts A22, A26, and A90 (nuclear) because nuclear plants in this size range have not been built.

The sources for the scaling equations are extrapolations of investment cost data from Oak Ridge National Laboratory and Honeywell Corporation (Reference 23, 24, and 25).

D.3 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 is used to relate 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.

The cost-of-capital model can determine 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.

The cost of capital for publicly owned electric utilities is also computed using the cost-of-capital model. The tax rate is assumed zero and the cost of capital becomes equal to the weighted average of (1) the effective interest rate, and (2) dividends on public equity capital.

The cost of capital is related to the assumed rate of inflation. In this study it is based upon historical data for the time period 1956 to 1972, assuming typical equal debt and equity ratios of 50 percent, and a combined state and federal income tax rate of 40 percent (References 26, 27). This historical time period was selected as an appropriate one to use as a basis for the future debt and equity costs, since the inflation rate in this time period (1956 - 1972: 2.9 percent per year) was virtually the same as has been assumed for the future (3 percent per year).

The cost of capital can be computed from the following relationship:

$$k = (E/V)\, k_e + (P/V)\, k_p + (L/V)\, k_\ell \tag{D-3}$$

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_ℓ are the cost of common equity, preferred stock equity, and long-term debt, respectively.

The return-on-common equity demanded by investors for this particular risk class (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:

$$D = (1-b)\, E \tag{D-4}$$

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

$$D = D_o \exp(gt) = (1-b)\, E_o \exp(gt) \tag{D-5}$$

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

$$P_o = \int_0^\infty D_o \exp(gt) \exp(-k_e t)\, dt = D_o/(k_e - g) \tag{D-6}$$

or

$$k_e = (D_o/P_o) + g \tag{D-7}$$

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

For example, in 1972 the electric utility industry dividend 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 (References 26, 27).

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

$$k_p = \frac{Fd}{P} \approx d \qquad \text{(D-8)}$$

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 (Reference 28):

$$P = \sum_{t=1}^{N} \frac{rF\ (1-\tau) + \tau\ (P-F)/N}{(1+k_\ell)^t} + \frac{F}{(1+k_\ell)^N} \qquad \text{(D-9)}$$

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 equations are, respectively, the present value of the after-tax interest expenses and the present value of the principal repayment at maturity.

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

D. 4 ESCALATION AND INTEREST-DURING CONSTRUCTION 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 costs components are addressed in considerable detail in the escalation and IDC computer model.

The detailed calculation of escalation and IDC uses cash flow curves of the type illustrated in Figure D-2 (Reference 24). The cash flows shown are representative of each two-digit account, and are in accordance with the standard classification of construction accounts, which represent the major subsystems of the plant (Reference 5). Also, the cash flows shown are representative of investment accounts for pressurized water reactor type nuclear power plants. However, others are stored in the program which are representative of investment accounts for other type power plants (Reference 25). 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 data 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 D-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 1956-1972 time period.

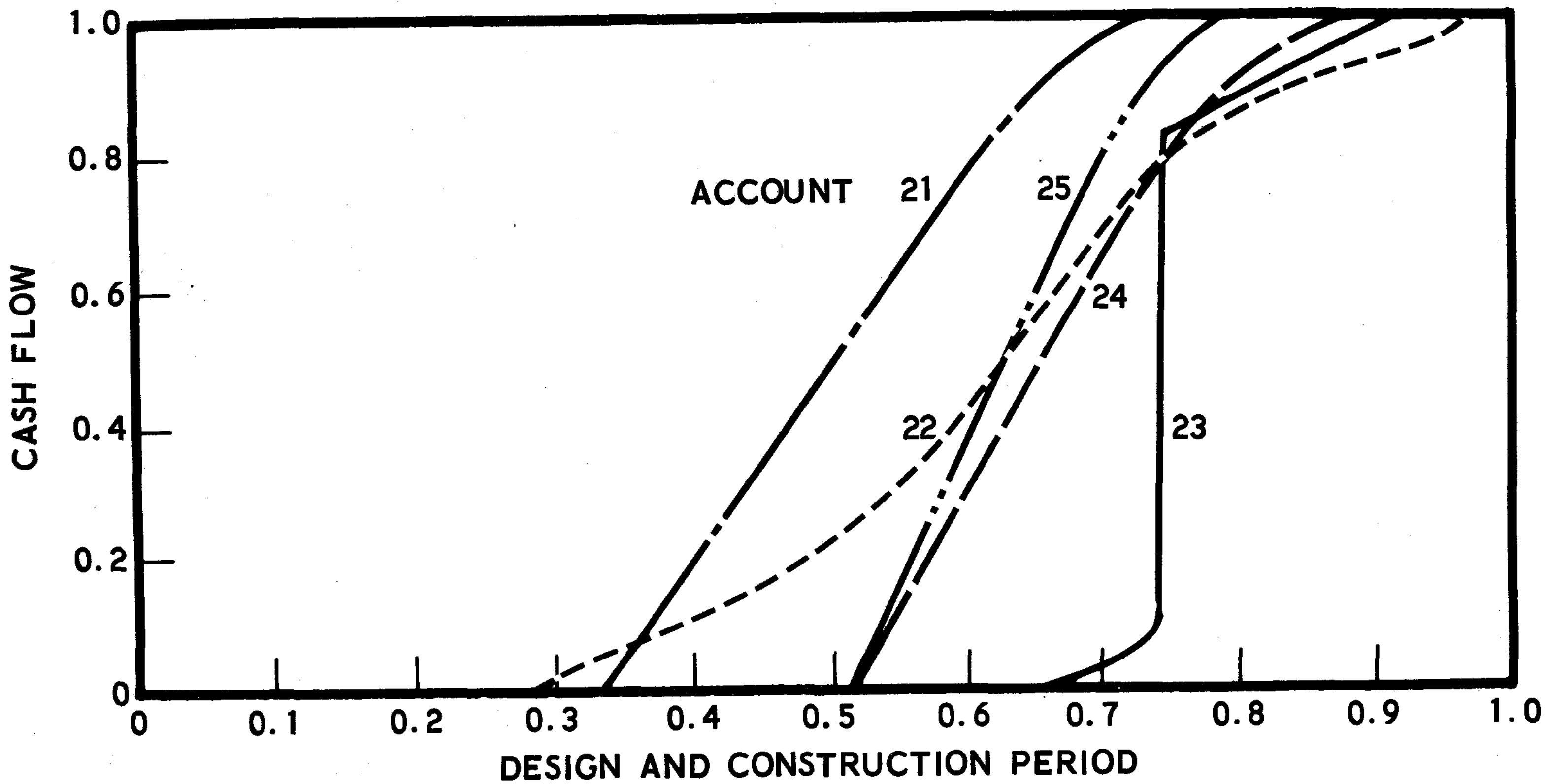

Figure D-2. Two-Digit Account Cash Flow Curves (Ref. 6)

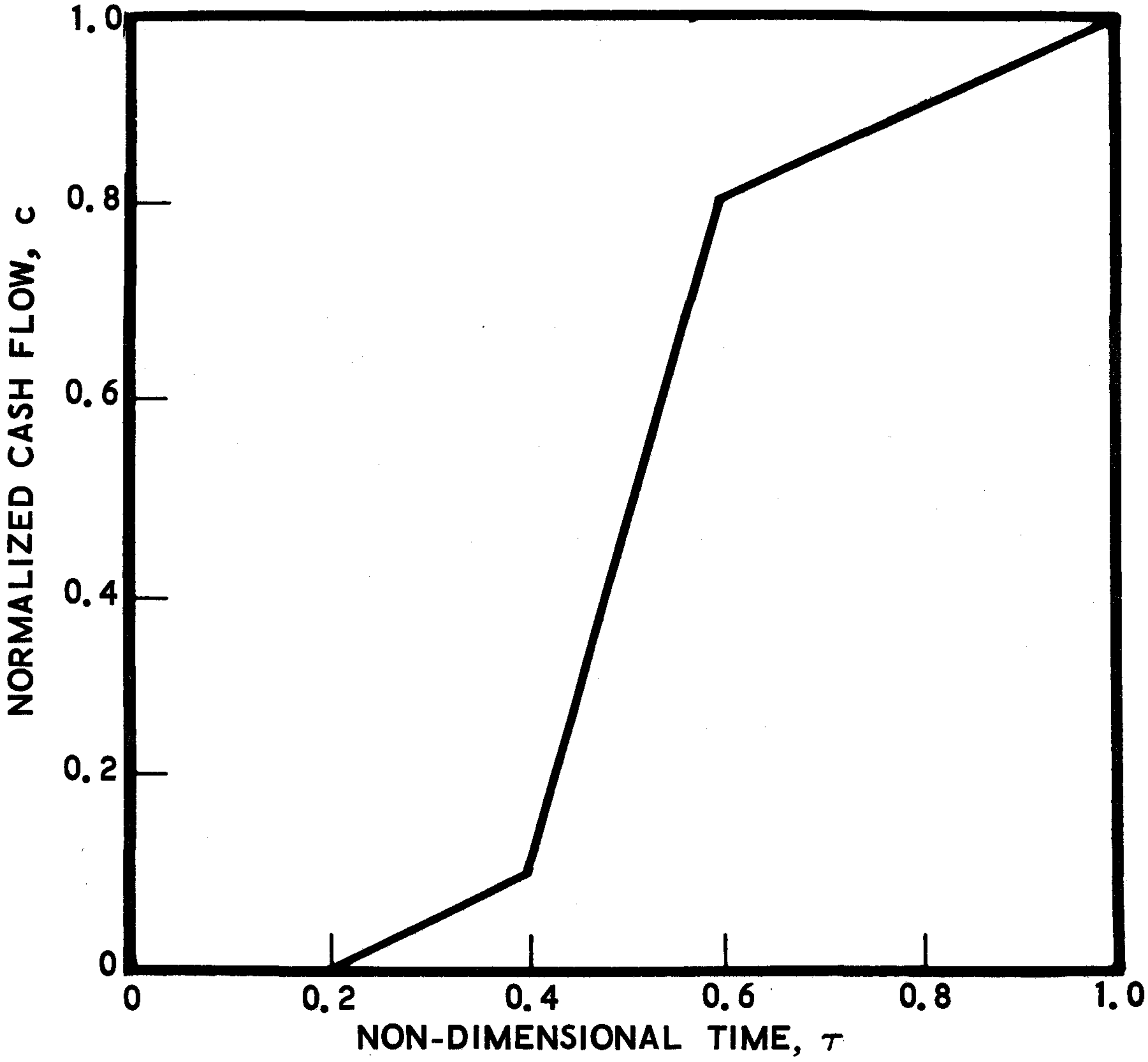

Figure D-3. Non-dimensional Cash Flow and Construction Time

Total investment cost (INV), interest during construction (IDC), and escalation cost (ESC) at time of commercial operation (co), are determined from the value of each two-digit account (j) at start of construction (sc) by the following relationships:

$$INV_{(j)_{co}} = INV_{(j)_{sc}} \int_0^1 \left\{\frac{dc\ (\tau)}{d\tau}\right\} \exp\left\{e\ (j)\ T\tau\right\} \exp\left\{kT\ (1-\tau)\right\}\ d\tau \quad \text{(D-10)}$$

$$IDC_{(j)_{co}} = INV_{(j)_{sc}} \int_0^1 \left\{\frac{dc\ (\tau)}{d}\right\} \exp\left\{kT\ (1-\tau)\right\}\ d\tau - INV_{(j)_{sc}} \quad \text{(D-11)}$$

$$ESC_{(j)_{co}} = INV_{(j)_{co}} - IDC_{(j)_{co}} - INV_{(j)_{sc}} \quad \text{(D-12)}$$

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) shown in Figure 2-3. The escalation rate e (j) during the construction time period (T) may vary for each account. Total capital investment (TCI) is computed by aggregating all investment accounts. Total IDC_{co} and ESC_{co} are thus determined.

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

2.5 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 can be determined from the pro forma annual income statements by deducting all cash outflows from the total busbar revenue allocated to the plant. Consequently, the total revenue less operating cash expenses for a power plant must be sufficient to recover both the total value of the capital investment (at the year of commercial operation) and a return on this investment as measured by the cost of capital.

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 discount rate (k) is the weighted average cost of capital (after income taxes) of equity and debt financing.

$$TCI_{co} = \sum_{i=1}^{N} (CF_i) \;/\; (1+k)^i + RV_N/(1+k)^N \qquad \text{(D-13)}$$

The total capital cost at year of commercial operation is the sum of the various subsystem costs, including escalation and IDC costs.

The residual value of the plant (RV) at the end of the useful plant life is the sum of the values of non-depreciable items such as land and thermal storage materials, less the expenses incurred at this time, such as nuclear plant decommissioning costs.

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

$$NI_i = (REV_i - EXP_i) \bullet (1 - TAXR) \qquad \text{(D-14)}$$

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

All revenue and expense accounts are normalized to plant capacity ($/KWe/YR) and all capital investment accounts are in $/(KWe).

Annual revenues (REV_i) for a plant, by utility industry definition, are equal to the total busbar energy costs ($BBEC_i$) attributable to the plant prior to transmission and distribution costs. The annual required revenues are defined such that the original investment is recovered as well as an adequate return on investment as determined by the cost of capital. The revenue and the total busbar energy cost can vary from year to year due to rate increases, which can be reflected by an escalation of the busbar energy cost/revenue rate.

$$BBEC_i = BBEC_{co} \bullet (1 + e_B)^i \qquad \text{(D-15)}$$

where e_B = escalation rate of busbar energy cost/revenue rate.

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 can be 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:

$$FUEL_i = \begin{cases} FUEL_{co} \bullet (1+e_{F_1})^{i} & 0 \le i < T \\ FUEL_T \bullet (1+e_{F_2})^{(i-T)} & T < i \le N \end{cases} \qquad \text{(D-16)}$$

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

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

$$FUEL_o = HR \times FC_o \bullet (1-SOLAR) \bullet CF \bullet 8760 \bullet 10^{-6} \qquad \text{(D-17)}$$

where HR = Heat Rate, Btu/Kwh

FC_o = Fuel Cost, \$/Million Btu at the base year

CF = Plant Capacity Factor

SOLAR = Percentage of energy supplied by solar energy.

Similarly, other operating ($OPEX_i$) expenses and insurance expenses (INS_i) can be computed.

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

$$INT_i = r \bullet LV \bullet TCI_{co} \qquad \text{(D-18)}$$

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.

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*Assuming no premium or discount.

Straight-line: $DEPR_i = DEBASE/N$

Sum-of-years-digits: $DEPR_i = DEBASE \bullet 2(N-i+1)/N\,(N+1)$ (D-19)

Double-declining: If $i < N$,

: $DEPR_i = DEBASE \bullet (2/N)\,(1-2/N)^{i-1}$

If $i = N$

: $DEPR_N = DEBASE \bullet (1-2/N)^{N-1}$

The residual value of the capital investment (RV_N) before 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:

$$RV_N = LAND_{co} \bullet (1+e_L)^N \tag{D-20}$$

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

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):

$$CF_i = NI_i + DEPR_i \tag{D-21}$$

or by rearranging terms

$$CF_i = (BBEC_i - FUEL_i - OPEX_i - INSU_i - INT_i) \bullet (1 - TAXR) + DEPR_i \bullet (TAXR) \tag{D-22}$$

By adjusting the total busbar energy revenues such that the net present value of these discounted cash flows is equal 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). This determines the total busbar energy cost for any year of operation.

The total busbar energy cost obtained can be tabulated in a format consistent with the electric power industry, in terms of variable costs (VC_i) and fixed charges (FC_i):

$$BBEC_i = VC_i + FC_i \tag{D-23}$$

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

$$VC_i = FUEL_i + OPEX_i \tag{D-24}$$

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

$$FC_i = COM_i + DEPR_i + INSU_i + TAX \tag{D-25}$$

This investment analysis model can be utilized to determine the relative economics of alternative power plants on a consistent basis. By varying the various design cost and economic parameters, the sensitivity of these design and economic parameters can be assessed. The system parameter variations, subject to design constraints, will allow the determination of the cost sensitivity of the total system to individual design parameter and option changes, using the above described model. From this sensitivity analysis, it is possible to determine the most competitive system and determine its economic attractiveness in comparison with other power plants. Furthermore, given the total busbar energy cost for a future (e.g., 1990) time period, such as from Federal Power Commission projections, an equivalent total capital investment can be imputed for a power plant. The imputed total capital investment becomes the design goal towards which a power plant must be designed in order to compete economically.

APPENDIX E

RECONCILIATION OF THE LEVELIZED FIXED CHARGE METHOD AND DISCOUNTED CASH FLOW METHOD

E.1 INTRODUCTION

An important criterion by which to judge the merits of alternative power plants is the relative economic assessment. Several methods exist for the economic evaluation of power plants. The discounted cash flow (DCF) analysis is the most sophisticated method used in financial investment analyses. This method has the greatest flexibility but is also the most complex, often requiring the use of a digital computer. The output of this method can either be in constant or current dollars.

The utility industry frequently uses the levelized fixed charge method which, on the surface at least, is relatively simple to use, but is less flexible. This method utilizes a predetermined (from DCF analysis) levelized fixed charge rate to compute the fixed charges. To be consistent, levelized variable costs should also be input to this method, which results in a levelized value of the busbar energy cost output. The purpose of this appendix is to derive an explicit expression for the levelized fixed charge rate.

E.2 PRIVATE OR INVESTOR OWNED UTILITIES

The power plant capital investment (CI_o) at the year of commercial operation including escalation and interest-during-construction must be financed. The cost-of-money (COM) for private or investor-owned utilities is the combined costs of equity (both common and preferred stock) and debt (long-term debentures). The interest payments (INT) constitute the return on debt, while the net income after taxes (NI) is potentially available to the equity holders:

$$COM_i = NI_i + INT_i \qquad \text{(subscript } i \equiv \text{year)} \qquad \text{(E-1)}$$

Net income after taxes (NI) is the earnings before taxes (EBT) less the corporate income taxes (TAX):

$$NI_i = EBT_i - TAX_i = EBT_i\,(1 - \tau) \qquad \text{(E-2)}$$

where: τ = Corporate Income Tax Rate

The net income (NI) and the earnings before taxes (EBT) can be obtained from the annual income statement:

$$EBT_i = BBEC_i - FUEL_i - O\&M_i - DEP_i - INS_i - OT_i - INT_i \qquad \text{(E-3)}$$

where: BBEC = Busbar Energy Cost or Annual Revenue Requirement, ($/yr)

FUEL = Annual Fuel Costs, ($/yr)

O&M = Annual Operating & Maintenance Costs, ($/yr)

DEP = Depreciation, ($/yr)

INS = Annual Insurance Premiums, ($/yr)

OT = Other taxes including property taxes, state income taxes, franchise taxes, and miscellaneous excise taxes, ($/yr)

Depreciation (DEP) can be computed by either the straight line (SL), sum-of-the-years-digits (S-Y-D), or double-declining (D-D) methods. For the purpose of this appendix, the straight-line (S-L) method is used:

$$DEP_i = CI_o/N \qquad \text{(straight-line)} \qquad \text{(E-4)}$$

Other taxes (OT) and insurance premiums (INS) are estimated as a percentage of the power plant capital investment (CI_o):

$$INS_i = \beta_1\,CI_o \qquad \text{(E-5)}$$

$$OT_i = \beta_2\,CI_o \qquad \text{(E-6)}$$

Typical values of insurance premium rates (β_1) are 0.25 percent, while state and local tax rates (β_2) are approximately 2.00-2.50 percent of the investment (CI_o).

Annual interest payments on long-term debt (INT) is computed from the interest rate (k_D) and proportion (D/V) of the total capital investment financed by debt:

$$INT_i = k_D \,(D/V)\, CI_o \tag{E-7}$$

The return on investment or cost-of-money (COM) is an annual percentage (γ) of the net book value (BV) of the investment:

$$COM_i = \gamma BV_i \tag{E-8}$$

Using a straight-line depreciation of the investment, the net book value of the investment at the ith year can be expressed as:

$$BV_i = CI_o - \sum_{j=1}^{i} DEP_i = (1 - i/N)\, CI_o \tag{E-9}$$

By combining Equations (E-4) thru (E-9) with Equations (E-1), (E-2) and (E-3), the annual revenue requirements or busbar energy costs can be expressed in terms of variable cost (VC) fixed charges (FC):

$$BBEC_i = \underbrace{COM_i + DEP_i + INS_i + OT_i + TAX_i}_{FC_i} + \underbrace{FUEL_i + O\&M_i}_{VC_i} \tag{E-10}$$

$$= FC_i + VC_i$$

where:

$$VC_i = FUEL_i + O\&M_i \tag{E-11}$$

and:

$$FC_i = COM_i + DEP_i + INS_i + OT_i + TAX_i \tag{E-12}$$

$$= \left[\left(\frac{1}{1-\tau}\right) \gamma \left(1 - i/N\right) - \left(\frac{\tau}{1-\tau}\right) k_D \left(D/V\right) + \frac{1}{N} + \beta_1 + \beta_2 \right] CI_o$$

As can be seen from Equation (E-12), the fixed charges are a function of the power plant capital investment @ year of commercial operation (CI_o). The term in the bracket of Equation (E-12) is called the annual fixed charge rate (FCR):

$$FCR_i = \left(\frac{1}{1-\tau}\right) \gamma \left(1 - i/N\right) - \left(\frac{\tau}{1-\tau}\right) k_D \left(D/V\right) + \frac{1}{N} + \beta_1 + \beta_2 \tag{E-13}$$

Consequently, the annual revenue requirement on busbar energy costs (BBEC) can simply be stated as:

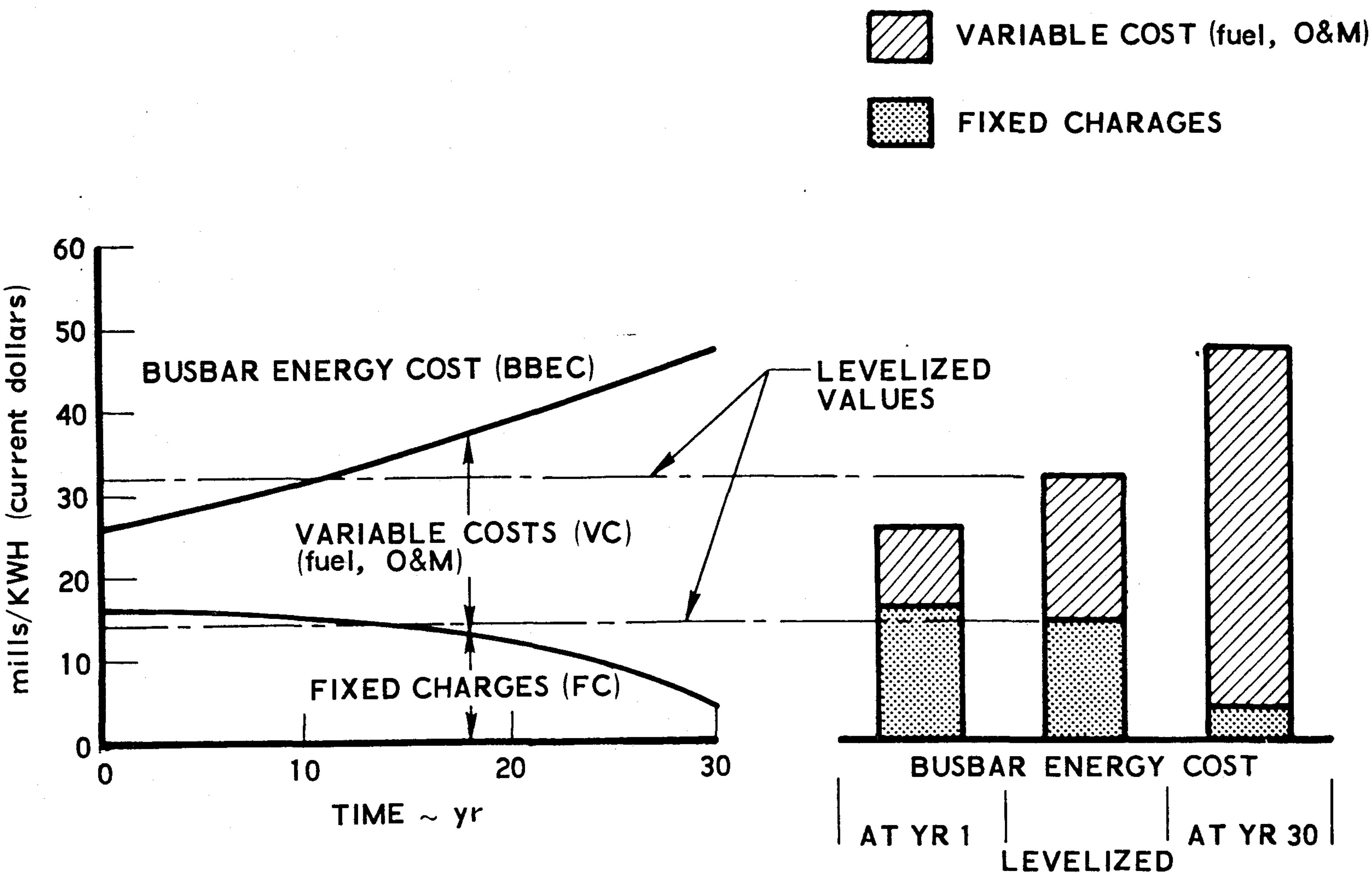
$$BBEC_i = (FCR_i)\, CI_o + FUEL_i + O\&M_i \tag{E-14}$$

Shown illustrative in Figure E-1 are the variable (fuel; operating & maintenance) and fixed charge components that make up the busbar energy cost in current dollars over the lifetime (N) of the plant. As can be seen in this example, the busbar energy cost and variable costs increase during the lifetime of the power plant, while the fixed charges typically decrease. All costs are expressed in current dollars.

The levelized values of these costs as derived by the discounted cash flow methods are also indicated in this figure. These levelized costs fall somewhere in between the first and last year costs as indicated by

FIGURE E-1

LEVELIZED FIXED CHARGE METHOD



the bar chart. The levelized values are constant costs over the lifetime of the plant which give the equivalent net present value when discounted at the cost of capital as the actual current costs. These levelized values do not precisely correspond to the actual costs experienced in any year during the operational lifetime of the plant.

The discount rate or cost-of-capital (k) is the after-tax weighted average cost of financing for the utility industry. This cost-of-capital is determined by the relative proportions of financing (capital structure) and costs of common equity, preferred equity, and long-term debt capital, respectively. The costs of financing represent the current return on investment required by the equity and debt holders as determined by the market place. Consequently, the weighted after-tax-cost-of-capital (k) is:

$$k = (C/V)\,k_C + (P/V)\,k_P + (D/V)\,k_D\,(1 - \tau) \qquad \text{(E-15)}$$

where C/V, P/V, and D/V are the respective proportions of common stock, preferred stock and debt financing and k_C, k_P, and k_D are the respective dividend and interest costs of financing. Since interest is tax deductible for corporations while dividends are not, the tax reduction (τ = corporate tax rate) is applied to interest costs only.

A typical capital structure for the private utility companies consists of 40 percent common stock, 10 percent preferred stock, and 50 percent long-term debt or debentures. Typical values of return on common stock are currently 12 percent. For preferred stock the cost is approximately represented by the yield which has a typical current value of 8 percent. The return on long-term debt includes the coupon rate and the final repayment of the debt and currently is estimated at 8 percent. With an average combined corporate tax rate of 40 percent, the private utility weighted cost-of-capital is therefore 8 percent, as can be seen in Table E-1. Also shown in this table is the effect of alternative capital structures and costs.

TABLE E-1

LEVELIZED FIXED CHARGE RATE (FCR)

UTILITY TYPE	COST OF COMMON EQUITY (k_C)	COST OF PREFERRED EQUITY (k_P)	COST OF LONG-TERM DEBT (k_D) (before taxes)	PERCENT OF COMMON EQUITY (C/V)	PERCENT OF PREFERRED EQUITY (P/V)	PERCENT OF LONG-TERM DEBT (D/V)	COMPOSITE CORPORATE TAX RATE (τ)	COST-OF-CAPITAL (k) (after taxes)	PLANT OPERATING LIFE-TIME (N)	LOCAL TAXES OR PAYMTS (percent of orig. inv.)	LEVELIZED FIXED CHARGE RATE (FCR)
PRIVATE	10	6	6	40	10	50	40	6.4	30	2	15.4
	10	-	6	50	-	↓	↓	6.8	↓	↓	15.9
	12	-	8		-			8.4			19.1
	12	8	8	40	10			8.0			18.6
	↓	↓	↓	↓	↓			↓		1	17.6
										3	19.6
							50	7.6		2	19.8
							40	8.0	25	↓	18.9
							↓	↓	20		19.6
MUNICIPAL	N/A	N/A	5	N/A	N/A	100	0	5.6	30	2	8.5
	↓	↓	6	↓	↓	↓	↓	6.0	↓	↓	9.3
			7					7.0			10.1
			8					8.0			10.9

Discounting Equation (E-14) results in the <u>levelized fixed charge method</u> expression. The levelized fixed charge method computes the busbar energy cost by adding the levelized fixed and levelized variable cost components:

$$\overline{BBEC} = (\overline{FCR})\, CI_o + \overline{FUEL} + \overline{O\&M} \tag{E-16}$$

The levelized values for busbar energy costs ($\overline{BBEC}$), fuel ($\overline{FUEL}$) and operating & maintenance (O&M), respectively, can be computed as follows:

$$\overline{BBEC} = \sum_{i=1}^{N} \frac{BBEC_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-17}$$

$$\overline{FUEL} = \sum_{i=1}^{N} \frac{FUEL_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-18}$$

$$\overline{O\&M} = \sum_{i=1}^{N} \frac{O\&M_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-19}$$

where the present value of an annuity of 1 is:

$$a_{\overline{N}|k} = \sum_{i=1}^{N} \frac{1}{(1+k)^i} = \frac{1-(1+k)^{-N}}{k} \tag{E-20}$$

Likewise, the levelized fixed charge rate $\overline{FCR}$ can be computed using Equation (E-12):

$$\overline{FCR} = \sum_{i=1}^{N} \frac{FCR_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-21}$$

$$= \left(\frac{1}{1-\tau}\right) \gamma \left(1 - \frac{a'_{\overline{N}|k}}{N\, a_{\overline{N}|k}}\right) - \left(\frac{\tau}{1-\tau}\right) k_D (D/V) + \frac{1}{N} + \beta_1 + \beta_2$$

where:

$$a'_{\overline{N|}k} = \sum_{i=1}^{N} \frac{i}{(1+k)^i} = \left(\frac{1+k}{k}\right) a_{\overline{N|}k} - \frac{N\,(1+k)^{-N}}{k} \qquad \text{(E-22)}$$

All components in Equation (E-21) are known with the exception of the annual percentage rate of return (γ). This rate can be obtained from the discounted cash flow (DCF) or net present value method.

For an investment (CI_o) to be economically attractive, the net present value of the net annual cash flows attributable to the investment must be equal to or greater than the capital investment. The net present value (NPV) of the annual cash inflows is derived by discounting the net cash flows at the cost-of-capital over the operating lifetime (N) of the plant:

$$CI_o \leq \sum_{i=1}^{N} \frac{CF_i}{(1+k)^i} \text{ (no salvage value)} \qquad \text{(E-23)}$$

The net annual cash flow (CF) is obtained from the income statement by adding to net income (NI) the depreciation (DEP). This is due to depreciation being an allowable expense for income tax purposes. However, depreciation constitutes a non-cash flow item, and consequently must be added back to obtain the annual net cash flow:

$$CF_i = NI_i + DEP_i \qquad \text{(E-24)}$$

Substituting Equation (E-1), the annual cash flow can be written in terms of cost-of-money and depreciation:

$$CF_i = COM_i - INT_i + DEP_i \qquad \text{(E-25)}$$

Substituting Equations (E-4) and (E-7) through (E-9), the annual cash flow is:

$$CF_i = \left[\gamma\,(1 - i/N) - k_D\,(D/V) + (1/N)\right] CI_o \qquad \text{(E-26)}$$

Discounting the annual cash flows at the cost-of-capital in accordance with Equation (E-23) results in an explicit expression for the annual percentage rate of return (γ):

$$CI_o = \left[\gamma\,(1 - \frac{a'_{\overline{N}|k}}{N\,a_{\overline{N}|k}}) - k_D\,(D/V) + \frac{1}{N}\right] CI_o\, a_{\overline{N}|k}$$

or

$$\gamma\,(1 - \frac{a'_{\overline{N}|k}}{N\,a_{\overline{N}|k}}) = \frac{1}{a_{\overline{N}|k}} + k_D\,(D/V) - \frac{1}{N} \qquad \text{(E-27)}$$

Substituting Equation (E-27) into the previously derived Equation (E-20) results in an explicit relationship for the levelized fixed charge rate ($\overline{FCR}$) for private or investor owned utilities:

$$\boxed{\overline{FCR} = (\frac{1}{1-\tau})\,\frac{1}{a_{\overline{N}|k}} + k_D\,(D/V) - (\frac{\tau}{1-\tau})\,\frac{1}{N} + \beta_1 + \beta_2} \qquad \text{(E-28)}$$

Table E-1 shows computed values of the levelized fixed charge rate as a function of the various parameters constituting this rate. These values, in conjunction with levelized values for fuel and operating & maintenance costs (Equations E-18 and E-19), can be used to estimate the levelized busbar energy cost ($\overline{BBEC}$):

$$\boxed{\overline{BBEC} = (\overline{FCR})\,CI_o + \overline{FUEL} + \overline{O\&M}} \qquad \text{(E-29)}$$

E.3 MUNICIPAL OR PUBLICLY OWNED UTILITIES

Municipal or publicly owned utility companies are typically financed by means of municipal bonds, which frequently provide for tax-exempt interest to the investors. Furthermore, municipal utility companies do not pay taxes. However, these companies are often required to make payments in lieu of taxes (PMT) to the municipality. Since there are no stockholders, the annual cash flows (CF) generated by the plant capital investment (CI_o), must be sufficient to amortize the debt (AMOR):

$$CF_i = AMOR_i = BBEC_i - FUEL_i - O\&M_i - INS_i - PMT_i - INT_i \qquad \text{(E-30)}$$

The sum of amortization (AMOR) and interest (INT) components of the debt constitute constant annual payments which can be expressed as a fixed rate (γ) of the investment:

$$AMOR_i + INT_i = \gamma \, CI_o \qquad \text{(E-31)}$$

Using <u>discounted cash flow analysis</u>, the amortization and interest can be discounted over the operational lifetime (N) of the plant at the cost-of-capital (k) to obtain an explicit expression for rate (γ):

$$CI_o = \sum_{i=1}^{N} \frac{AMOR_i + INT_i}{(1+k)^i} = \gamma \, a_{\overline{N}|k} \, CI_o \qquad \text{(E-32)}$$

or:

$$\gamma = \frac{1}{a_{\overline{N}|k}} \qquad \text{(E-33)}$$

where:

$$a_{\overline{N}|k} = \sum_{i=1}^{N} \frac{1}{(1+k)^i} = \frac{1 - (1+k)^{-N}}{k} \qquad \text{(E-34)}$$

For municipal or publicly-owned utility companies, the discount rate or cost-of-capital (k) is the interest rate of bond financing:

$$k = k_D \qquad \text{(E-35)}$$

The interest on municipal bonds is frequently tax exempt for the bond holders and, consequently, typically carries a lower premium than corporate bonds. A typical current value is 6 percent. Insurance premiums (INS) and payments in lieu of taxes (PMT) are related to the plant capital investment by annual rates (β'):

$$INS_i = \beta'_1 \, CI_o \qquad \text{(E-36)}$$

and:

$$PMT_i = \beta'_2 \, CI_o \qquad \text{(E-37)}$$

A typical value for the insurance rate (β'_1) is 0.25 percent, while the payment in lieu of taxes rate (β'_2) may vary from 1.00 to 2.00 percent.

Using Equation (E-30) the annual revenue requirements or busbar energy cost (BBEC) can again be expressed in terms of fixed charges (FC) and variable costs (VC):

$$\begin{aligned} BBEC_i &= \underbrace{AMOR_i + INT_i + INS_i + PMT_i}_{FC_i} + \underbrace{FUEL_i + O\&M_i}_{VC_i} \\ &= FC_i + VC_i \end{aligned} \qquad \text{(E-38)}$$

Substituting Equations (E-34) thru (E-37):

$$BBEC_i = (\gamma + \beta'_1 + \beta'_2) \, CI_o + FUEL_i + O\&M_i \qquad \text{(E-39)}$$

The term in the bracket of Equation (E-39) is the annual fixed rate (FCR):

$$FCR = \gamma + \beta_1' + \beta_2' \tag{E-40}$$

Since fuel and operating & maintenance costs vary over the operational life of the plant, the terms in Equation (E-39) can be levelized by discounting at the cost-of-capital (k):

$$\overline{BBEC} = (\overline{FCR})\, CI_o + \overline{FUEL} + \overline{O\&M} \tag{E-41}$$

where:

$$\overline{BBEC} = \sum_{i=1}^{N} \frac{BBEC_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-42}$$

$$\overline{FUEL} = \sum_{i=1}^{N} \frac{FUEL_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-43}$$

$$\overline{O\&M} = \sum_{i=1}^{N} \frac{O\&M_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-44}$$

and

$$\overline{FCR} = \sum_{i=1}^{N} \frac{FCR_i}{(1+k)^i} \Big/ a_{\overline{N}|k} \tag{E-45}$$

$$= \gamma + \beta_1' + \beta_2'$$

By substituting the result of the discounted cash flow analysis Equation (E-36), the levelized fixed charge rate can be explicitly expressed as:

$$\boxed{\overline{FCR} = \frac{1}{a_{\overline{N}|k}} + \beta_1' + \beta_2'} \tag{E-46}$$

Table E-1 shows computed values of the levelized fixed charge rate as a function of the various parameters constituting this rate. These values, in conjunction with the levelized values for fuel and operating & maintenance costs [Equations (E-43) and (E-44)], can be used to estimate the levelized busbar energy cost ($\overline{BBEC}$):

$$\boxed{\overline{BBEC} = (\overline{FCR})\ CI_o + \overline{FUEL} + \overline{O\&M}} \tag{E-47}$$

E.4 SUMMARY

An alternative method to the discounted cash flow or present value economic evaluation of power plants is the levelized fixed charge method. This method is widely used in the utility industry for quick calculation of the busbar energy cost.

As has been shown in detail in this appendix, the levelized fixed charge method is derived from the discounted cash flow methodology, and when applied correctly will yield equivalent results. Levelized values of fuel and operating and maintenance costs must be input which, when combined with the fixed charges as estimated by the levelized fixed charge rate, result in a levelized busbar energy cost.

Typical values for the levelized fixed charge rate ($\overline{FCR}$) are shown in Table E-1 for both private and municipal utility companies. These levelized $\overline{FCR}$s were derived from the discounted cash flow analysis as discussed in this appendix. As can be seen, the $\overline{FCR}$ is a function of the financial structure

By substituting the result of the discounted cash flow analysis Equation (E-36), the levelized fixed charge rate can be explicitly expressed as:

$$\boxed{\overline{FCR} = \frac{1}{a_{\overline{N|}k}} + \beta_1' + \beta_2'} \qquad \text{(E-46)}$$

Table E-1 shows computed values of the levelized fixed charge rate as a function of the various parameters constituting this rate. These values, in conjunction with the levelized values for fuel and operating & maintenance costs [Equations (E-43) and (E-44)], can be used to estimate the levelized busbar energy cost ($\overline{BBEC}$):

$$\boxed{\overline{BBEC} = (\overline{FCR})\ CI_o + \overline{FUEL} + \overline{O\&M}} \qquad \text{(E-47)}$$

E.4 SUMMARY

An alternative method to the discounted cash flow or present value economic evaluation of power plants is the levelized fixed charge method. This method is widely used in the utility industry for quick calculation of the busbar energy cost.

As has been shown in detail in this appendix, the levelized fixed charge method is derived from the discounted cash flow methodology, and when applied correctly will yield equivalent results. Levelized values of fuel and operating and maintenance costs must be input which, when combined with the fixed charges as estimated by the levelized fixed charge rate, result in a levelized busbar energy cost.

Typical values for the levelized fixed charge rate ($\overline{FCR}$) are shown in Table E-1 for both private and municipal utility companies. These levelized $\overline{FCR}$s were derived from the discounted cash flow analysis as discussed in this appendix. As can be seen, the $\overline{FCR}$ is a function of the financial structure (equity/debt) and costs of financing, the corporate tax rate, plant operational lifetime, and salvage value of the investment. Also shown is the after-tax cost of capital, as determined by the financial structure of the utility. In the case of municipal utility companies, no corporate taxes are levied and the cost of financing is by means of debt only, often in the form of tax-free municipal bonds.

Even though the levelized fixed charge method appears simple at first glance, the correct use of this method is often quite complex and, consequently, time consuming as well as subject to errors in interpretation. In this study for the comparative economic evaluation of the alternative solar thermal conversion systems and conventional power plants, the more flexible computerized discounted cash flow method described previously was used.