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Some Considerations Related to Capacity Credit for Central Station Solar Power Plants

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SOME CONSIDERATIONS RELATED TO CAPACITY CREDIT FOR CENTRAL STATION SOLAR POWER PLANTS

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ABSTRACT

Solar power plants will incur both mechanical and insolation outages. This work considers the reliability of a solar electric plant by estimating the likelihood that insolation outages will occur on days when system load is likely to be high. Since high electrical load occurs on the hottest days of the year for many utilities (those designated as "summer peaking"), much insight into solar plant reliability is obtained by analyzing direct normal insolation on these days. The relationship between quantity and reliability of direct normal insolation is examined for sites such as El Paso, Madison, Miami, and Phoenix. The relative impact of mechanical versus insolation specifications is considered for Miami. Finally, the use of geographic dispersion to improve the reliability of electrical generation via solar energy is examined for Phoenix and El Paso.

CONTENTS

SOME CONSIDERATIONS RELATED TO CAPACITY CREDIT FOR CENTRAL STATION SOLAR POWER PLANTS

I. Introduction

What is the value of a solar plant to a utility? An immediate response is that by generating electricity via the sun, the solar plant saves exhaustible fuels such as oil and natural gas and as the relative price of these fuels increases, so does the potential impact of a solar plant on the operational costs of a utility. But in addition to this, it is expected that the introduction of solar plants into a utility will obviate the need for building other power plants, thus affecting capital costs. The capacity credit of a solar plant is a measure of the amount of conventional generating power it replaces. In assessing plant options, a utility planner must do more than merely insure that the installed capacity is sufficient to satisfy the peak demand of the projected load. His concern is also to maintain a predetermined margin of system reliability--standards varying, with typical criteria being that the load be satisfied for all but at most one hour in twenty years or one day in ten years.

Formerly, the utilities insured reliability by simply building enough plants so that the difference between the installed generating capacity and the peak demand was, for example, either 15% of the system peak or equal to the rating of the largest plant. Recent utility efforts to minimize capital expenditures have been assisted by computer simulations based on detailed analysis of individual plant reliability.

For conventional plants (e.g., fossil fuel, coal, nuclear), forced outages are largely the result of randomly occurring mechanical failures. It is reasonable to anticipate that advanced technology solar plants will encounter mechanical failures of frequency and duration similar to those of conventional plants, but in addition, solar plants will experience derating and outage due to poor insolation. Of course, there are anticipated daily and seasonal fluctuations in insolation which affect the total electrical output of the plant, but it is the unexpected outages due to clouds and storms which make the solar plant less reliable than a conventional plant and whose impact on reliability, in the absence of experience, is difficult to assess.

II. Summary and Conclusions

Capacity credit for solar plants may be enhanced by the positive correlation of peak load with good insolation; previous studies which ignored this correlation may have yielded pessimistic approximations to capacity credit, as suggested by examination of Phoenix insolation in Section V.

The capacity credit of solar plants in sites of comparable average daily direct normal insolation may vary significantly. Two such sites, Madison and Miami, are analyzed in Section VII.

The relative impact of the insolation and mechanical specifications of a solar plant on capacity credit vary as a function of the percentage of the year during which operation is necessary to insure system reliability. The conclusions, discussed in Section VI, are expected to be sensitive to the insolation profile of the site.

Geographic dispersion of a collection of solar plants will reduce the probability of coincident outage and thereby improve the overall reliability of solar energy to the utility. The situtation considered here is a load in Phoenix and the options of two plants to be located either both in Phoenix, or both in El Paso, or one in each location. The choice reduces to building a back-up plant in Phoenix or transmission lines to El Paso, with the details contained in Section VIII.

III. Discussion of Capacity Credit

The capacity credit of a solar plant is a measure of its reliability relative to that of a conventional plant. To illustrate, suppose that a utility comprised of a specified mix of conventional plants is able to satisfy the load with a given reliability. If an m MW_e conventional unit is replaced by an m MW_e solar plant, there exists a smallest conventional plant (with generating capacity between 0 and m MW_e) which must be added to the altered system in order that the load may be satisfied subject to the same reliability criterion. If, for example, m is equal to 200 in the definition above and a 75 MW_e conventional plant is sufficient to back up the 200 MW_e solar plant, then the solar plant is assigned a capacity credit of 125 MW_e for the conventional generating power it replaces.

Of course, the capacity credit of a solar plant is sensitive to a myriad of factors: the standard of reliability imposed by the utility, the load profile, the insolation data, the mix of generating units in the original system, and the dispatch strategy for the operation of the solar plant and more generally for the interaction of all of the plants in the grid. To illustrate briefly how the alteration of but one of these factors (namely, the dispatch strategy) affects the capacity credit assigned to a solar plant, consider the following scenario: a system planner models a to-be-introduced solar plant as a "peak-shaver" so as to maximize its capacity credit and consequently minimize overall utility capital costs. Ignorant of this, the system operator dispatches the installed solar plant as a "fuel-saver" so as to minimize utility operational costs, thus causing a blackout whose duration exceeds the criterion established by the utility, illustrating the effective difference in capacity credit for the planned versus operating solar plant.

IV. Methodology

Ideally, an assessment of capacity credit should be derived from an analysis of coincident load and insolation data for many years. Since there is only a limited amount of such data, previous studies have either employed synthetic load data or have calculated capacity credit based on data from a single year. With the first approach, if days of high load are assumed to have typical insolation, a likely result is to underestimate the capacity credit of the solar plant, as demonstrated in Section V. With the second approach, error may be introduced by an analysis of insolation on a few days of an unusual year. Suppose, hypothetically, that high system load is experienced on those days of the year on which there is a high air conditioning load, and that these days include all for which the peak recorded temperature is greater than 95°F. Figures 1 and 2 reveal that in Albuquerque, New Mexico, there was one day in 1956 for which the total direct normal insolation was less than 2.5×10^4 kJ, whereas in 1955, insolation on the worst such day was better than 3.2×10^4 kJ. Depending on how the calculation is made, there is a variation of 20 to 30 percent in these figures, suggesting that there could be a similar variation in calculations of capacity credit based on a single year.

ALBUQUERQUE (1956)

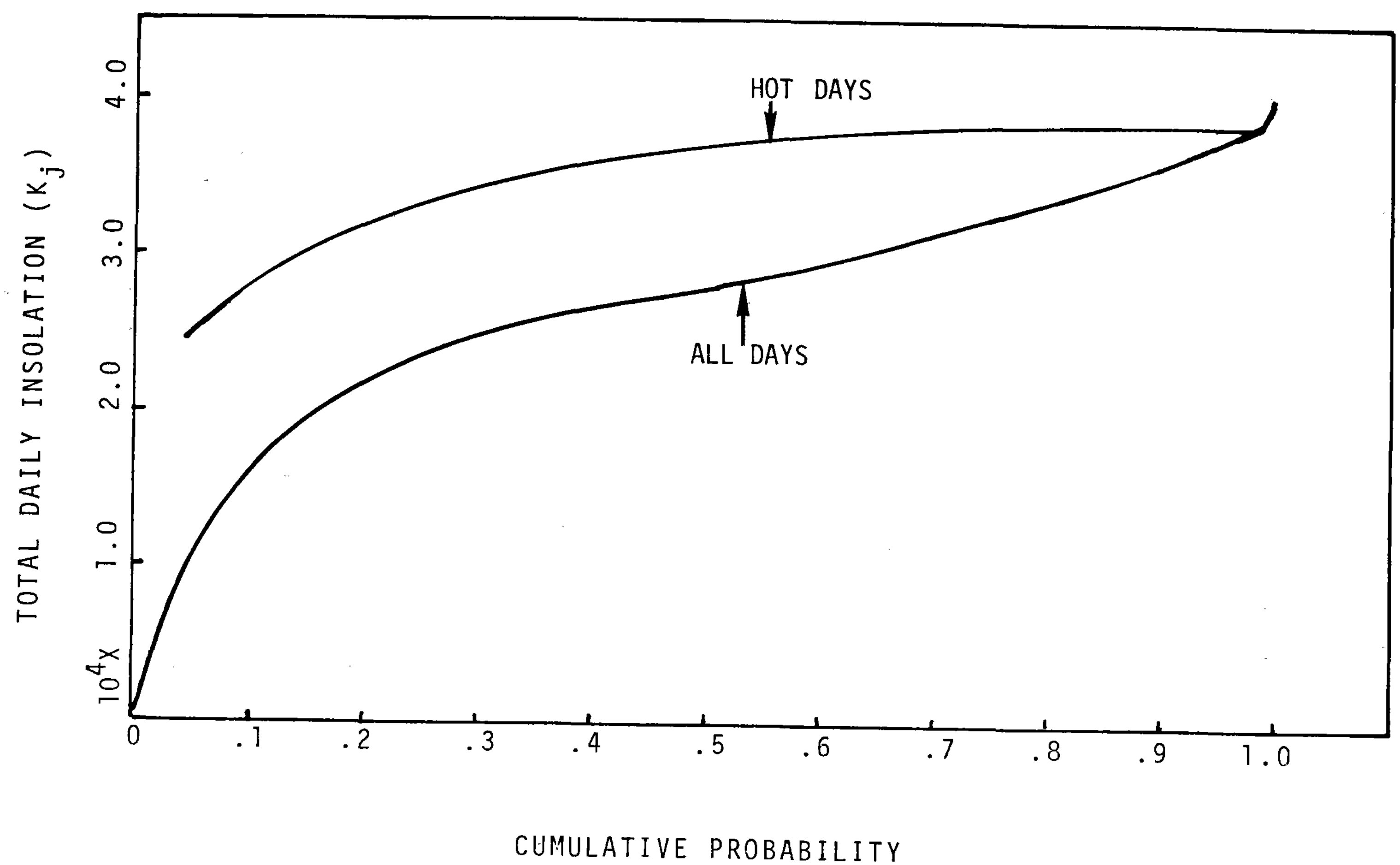


FIGURE 1

ALBUQUERQUE (1955)

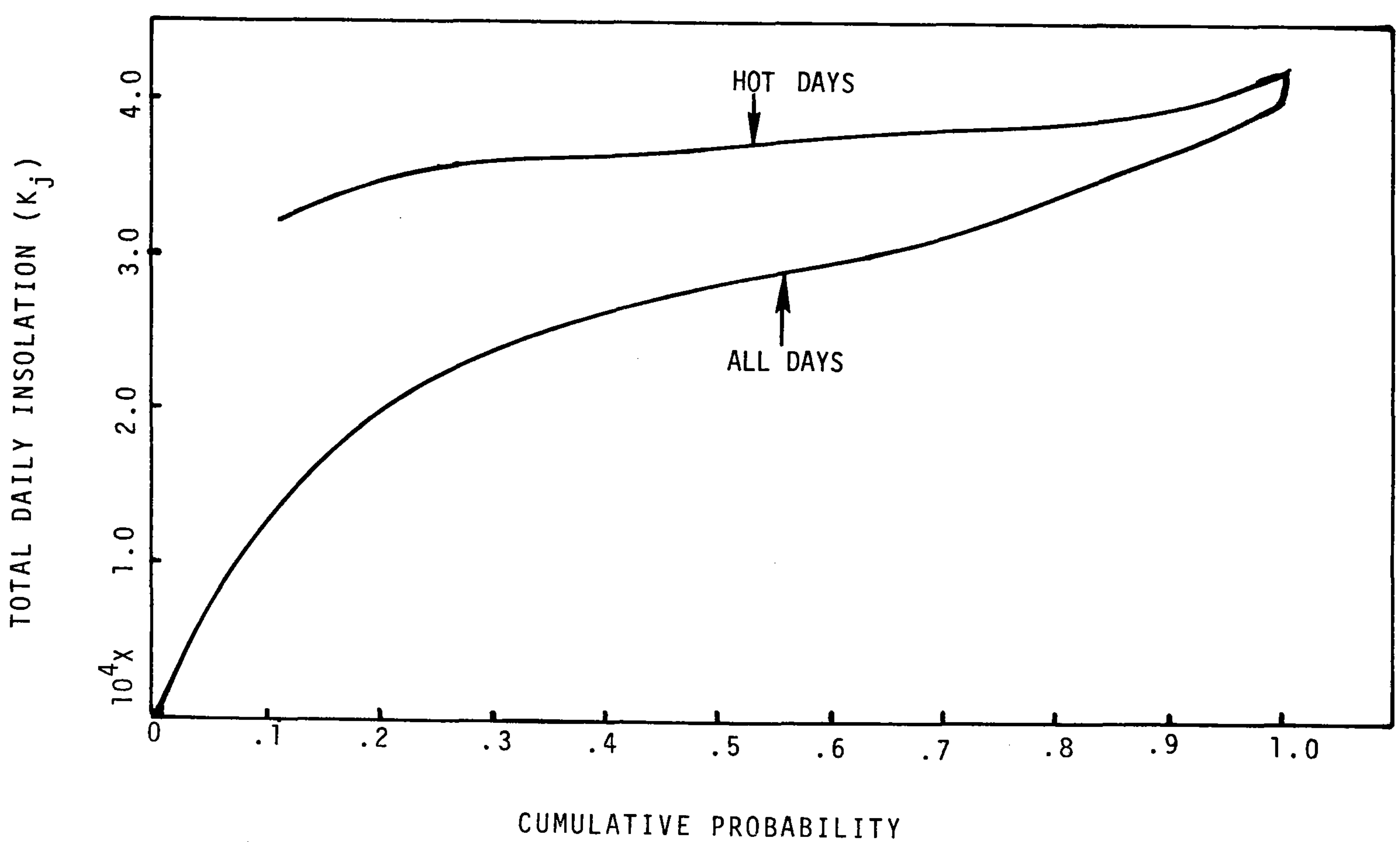


FIGURE 2

In this study, the capacity credit for a solar plant is analyzed by examining Solmet weather data (Ref. 1) for many years (typically 22) at each of several locations. As mentioned earlier, the capacity credit of a solar plant is strongly influenced by its performance at times of high system load and for Miami and Madison, these generally include the hottest days of the year (Figures 3 and 4); it must be cautioned, however, that a few days of high temperature and low load in Madison correspond to weekends and national holidays.

Figure 5 is a schematic representation of the manner in which the Solmet data will be used to compare solar plant performance on a hot, as opposed to typical, day. The solid curve in Figure 5 represents daily direct normal insolation and is based on data for many years. The x-axis represents cumulative probability while the y-axis represents insolation. Suppose, for example, that one desires to know the probability that the total insolation is less than or equal to I; the location of the point on the solid curve whose ordinate value is I and whose abscissa value is D yields the desired information.

The dotted curves are similarly interpreted, although they reflect insolation on days of high temperature occurring in the same time interval. To calculate the expected number of hot days of the year for which the insolation is less than or equal to I, identify the point (P, I) on the curve and multiply P by H/N, where H is the number of hot days in N years. The two dotted curves are included to contrast two extreme examples of solar plant operation on the hot days of the year. Note that the dotted line labeled "poor capacity credit" closely approximates the solid curve, indicating that the insolation seen by the solar plant on hot days does not differ significantly from that seen on typical days. Note that the dotted curve labeled

SCATTERGRAM OF DAILY LOAD AND TEMPERATURE FOR SOUTHEAST FLORIDA (1976)

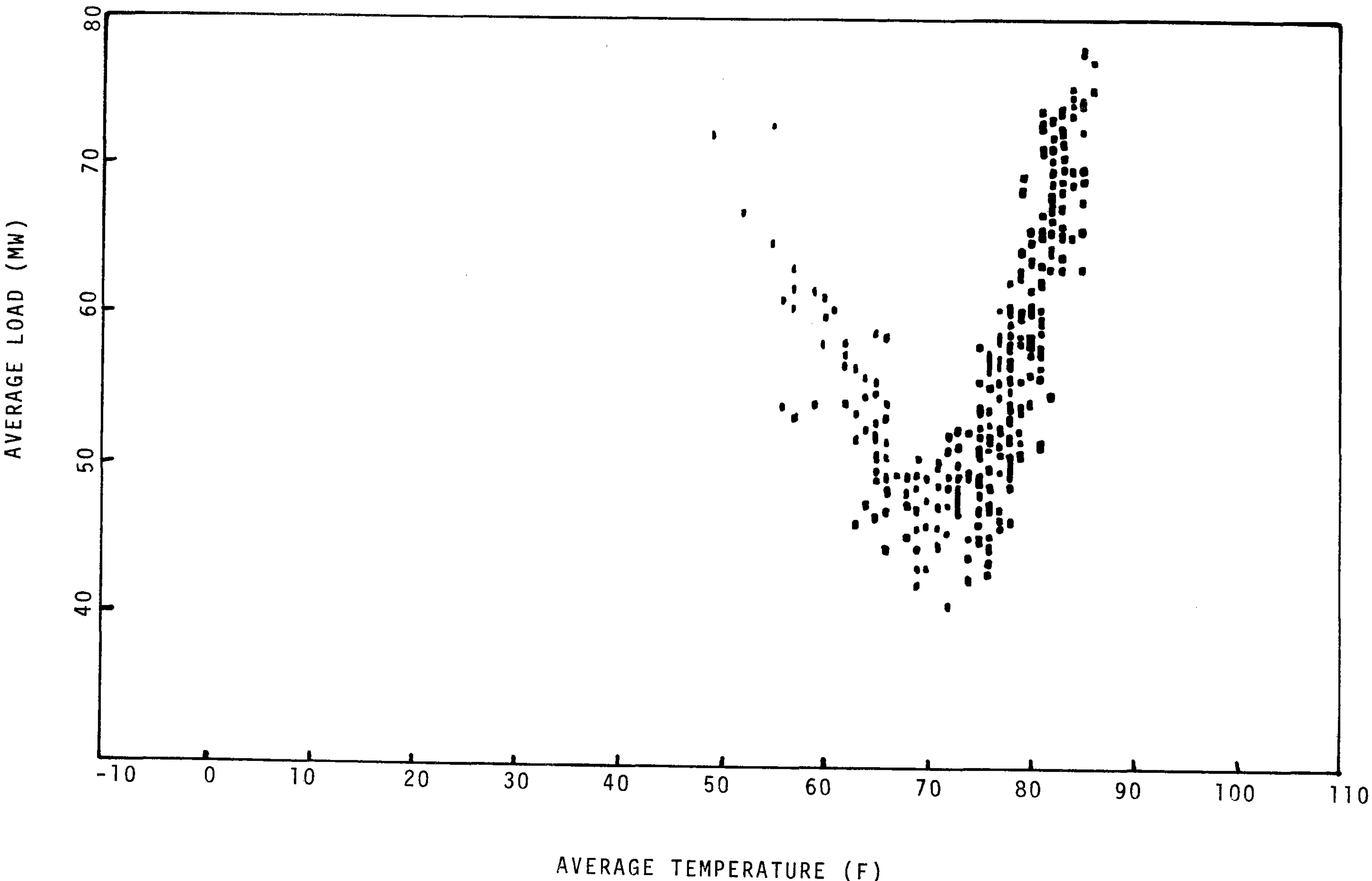


FIGURE 3

SCATTERGRAM OF DAILY LOAD AND TEMPERATURE FOR NORTH CENTRAL WISCONSIN (1975)

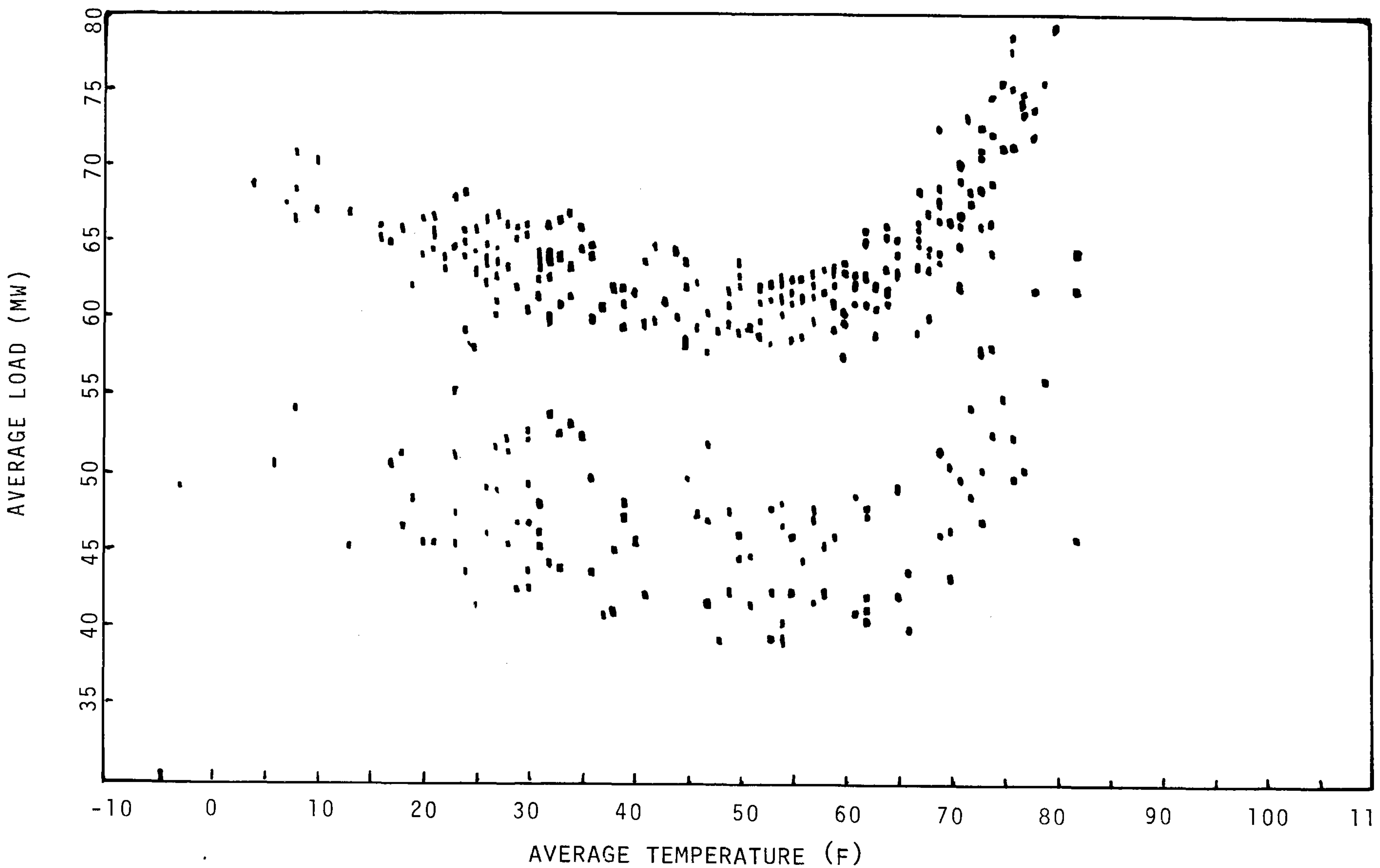


FIGURE 4

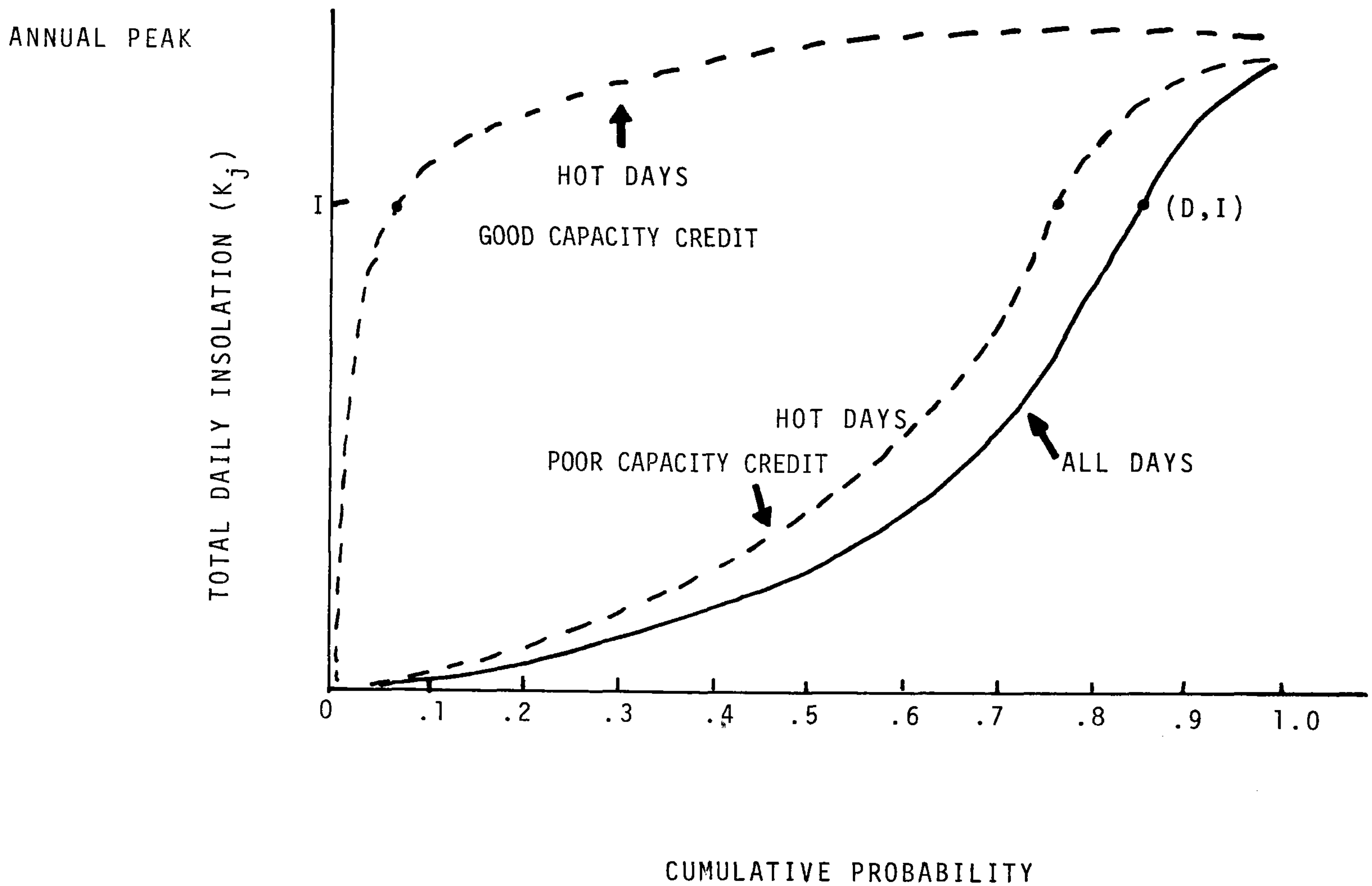

ANNUAL PEAK
TOTAL DAILY INSOLATION (K_j)
I
HOT DAYS
GOOD CAPACITY CREDIT
(D,I)
HOT DAYS
POOR CAPACITY CREDIT
ALL DAYS
0
.1
.2
.3
.4
.5
.6
.7
.8
.9
1.0
CUMULATIVE PROBABILITY

FIGURE 5

"good capacity credit" corresponds to insolation at a site for which the solar plant can be expected to perform relatively well on the hot days of the year. For summer peaking systems, high load is experienced on hot days so that solar plant reliability is strongly influenced by insolation on these days.

The main simplifying assumption has been to consider solar plant performance only when the temperature is high. Although most utilities are in fact summer-peaking, note from Figure 3 that the Miami electric load is also high on the coldest days of the year, because of the prevalence of electric heating in this region. Such days must also be considered for an exact calculation of solar plant capacity credit, but are excluded from the analysis here.

V. A Specific Example: Phoenix

The observation that the hotter the temperature the better the insolation is illustrated in Figure 6 for a specific site, Phoenix, over a period of fourteen years (1953-1966). Notice that the plant performs better on hot days (>95°F) and best on the hottest days (>104°F). An example of direct comparison is obtained by noting that the insolation is less than or equal to half of the maximum for roughly 35% of all days, 10% of the hot days, and 2.57% of the hottest days (where the maximum is 4.4×10^4 Kj). Note that the minimum total daily insolation on the hottest days observed over the inclusive period 1953-1966 is 37.5% of the maximum (achieved during the same period) so that it is reasonable to expect the solar plant to operate during at least <u>part</u> of each of the hottest days of its lifetime. However, the daily insolation is less than half of the maximum on 2.57% of the hottest days of the year, and since there are 40 hottest days of a typical year, 2.57% x 40 = 1 day, with the result that in an average year there will be one hottest day

PHOENIX (1953 - 1966)

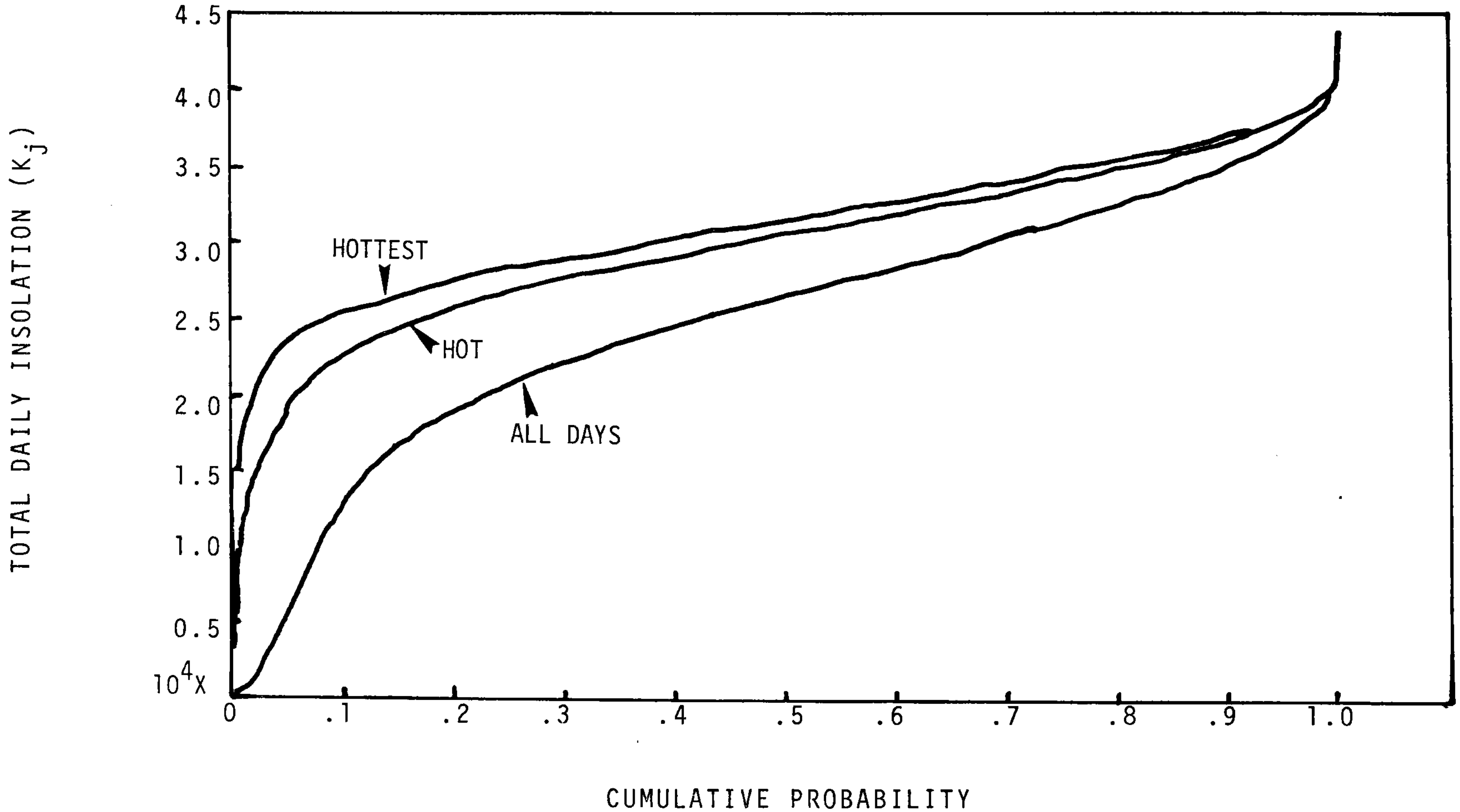


FIGURE 6

on which the total insolation seen by the solar plant will be less than half of the annual maximum. On such a day it is possible that the solar plant could experience difficulty in meeting its obligation to the utility because of operational constraints (e.g., minimum flow, start-up and shut-down requirements). It therefore appears that even for a site of excellent insolation, operational considerations may affect the capacity credit of the plant so that the choice may be to build an operationally more efficient solar plant or to add to it dedicated storage or a larger back-up conventional plant.

VI. The Relative Impact of Uncertainties: Miami

Several uncertainties are involved in the type of analysis done in the previous section:

1. The effect of low insolation on solar plant operation
2. The relationship between temperature and high load
3. The mechanical forced outage rate of a solar versus conventional plant

The sensitivity of the results to the above factors is illustrated for Miami in this section.

1. Low Insolation

For the first of these, reliability is examined under two different assumptions--that the solar plant does not collect any energy when insolation is less than either 25% or 10% of that available on the best day of the year. The 25% assumption is reasonable when the low insolation level is due to frequent fluctuations in insolation over the day caused by cloud cover. However, if the low readings reflect insolation which is extremely good for a period of several hours but poor otherwise, then the 10% cut off assumption is more reasonable as it is expected that the solar plant would collect essentially all of an available 25% insolation. Since direct normal readings were hourly at best and usually derived from a model (e.g. Solmet) rather than measured they do not discriminate between the above weather conditions, thus introducing the first uncertainty.

2. Temperature and High Load

For the second of those uncertainties, it is assumed in this study that high load occurs on those days for which a specified peak recorded temperature is attained. It could be argued that the average temperature between 10 a.m. and 10 p.m. is a better indication of load than is peak daily temperature. Furthermore, a variety of factors, not the least of which is humidity, could mean that a peak temperature of 86°F causes homeowners to turn on air conditioners in Miami but not in Phoenix, thus forcing different load requirements; therefore, insolation is examined (Table I) for all days of the year for which the peak Miami temperature is either above 86°F or 89.6°F or for which the daily average temperature (between 10 am and 10 pm) is above 73.5°F. The first column indicates the level above which the days are selected on the basis of peak or average temperature; column 3 indicates the number of those days on which the insolation is less than 10% (respectively 25%) of the maximum total daily insolation over the year.

3. Mechanical Outage

A conventional power plant might be expected to have a probability of forced outage of .05, although there is considerable variation depending on type, rating, and age (Ref. 4). Since certain aspects of solar plant technology (e.g. heliostats) are relatively new, a probability of forced outage of .1 is considered in addition to .05; although the number of days of mechanical outage corresponding to .1 and .05 do not appear in any table, they are incorporated with the number of days of outage due to poor insolation (contained in Table I) to obtain the total number of days of non-operation in Table II.

TABLE I

NUMBER OF HOT DAYS WHICH HAVE POOR INSOLATION IN MIAMI

Temperature Above: Peak	Temperature Above: Average	Average Number of Such Days Per Year (Percent of Year)	Average Number of Selected Days Per Year For Which Insolation Less Than Indicated: 10%	25%
86°F		120(33%)	3	18
89.6°F		23(6%)	.29	1.15
	73.5°F	5(1%)	.38	1.15

TABLE II

TOTAL NUMBER OF SELECTED DAYS FOR WHICH OUTAGE IS EXPECTED IN MIAMI

Percentage of Days of Mechanical Outage	Percentage of Maximum Insolation Required for Operation: 10%	25%	
10%	15	30	Peak Above 86°F
	2.59	3.45	Peak Above 89.6°F
	.88	1.65	Average above 73.5°F
5%	9	24	Peak Above 86°F
	1.44	2.30	Peak Above 89.6°F
	.63	1.40	Average Above 73.5°F

Results

- Solar plant reliability is quite sensitive to the minimum allowable insolation level (10% or 25%), as indicated by column 3 of Table I. The greater the percentage of the year that operation of the solar plant is required to insure system reliability, the greater the impact of the minimum insolation level on reliability, as indicated by the numbers derived from Table I:

Percentage of the Year	Ratio of Number of Days of Insolation Outage (25%/10%)
33%	6
6%	4

- A glance at Table II reveals that if a choice can be made between a low minimum insolation percentage and a high mechanical forced outage rate or a high minimum insolation percentage and a low mechanical forced outage rate, the former is preferable except for days with peak temperatures above 89.6°F. This suggests that solar plant capacity credit may increasingly depend on minimun insolation specifications if operation is required for an extremely high (33%) or low (1%) percentage of the year.
- The capacity credit for a solar plant may depend on whether peak or average daily temperature is a better indicator of load for by glancing at columns 2 and 3 of Table I, it can be seen that the first of these is much better correlated with good insolation than is the second. Specifically, the probability of receiving less than 25% of the insolation is .05 (1.15/23) for the first type of day compared to .23 (1.15/5) for the second. This difference is explained by a high incidence of uniformly

warm but cloudy days in Miami, graphically displayed by Figure 7 in which the curve representing insolation on a day for which the average temperature is at least 73.5°F partially lies below the curve representing insolation on an arbitrary day.

- Regardless of what assumptions are made about insolation specifications, load requirements, and mechanical forced outage rates, the (previously defined) measure of the reliability of a solar versus conventional plant varies by at most a factor of 2, as indicated in Table III (a low of 46% to a high of 91%).

To understand the derivation of the numbers in Table III, it is important to recall that a conventional power plant is assumed to have a total probability of forced outage of .05. If F_s denotes the forced outage rate (mechanical and insolation) for the solar plant, then to improve the reliability of the solar portion of the system it is necessary to add N such plants (geographically distributed so that outages are uncorrelated), where $.05 = F_s^N$. Hence, $N = \frac{\ell n(.05)}{\ell n(F_s)}$ and the reliability percentage for the solar plant is $\frac{1}{N} \cdot 100\%$. Of course the figures so obtained are too optimistic, as it is impossible to build fractions of solar plants, insolation outages are correlated to some degree, and operational constraints (start up and shut down delays, field efficiency, etc.) have been ignored.

MIAMI (1953 - 1974)

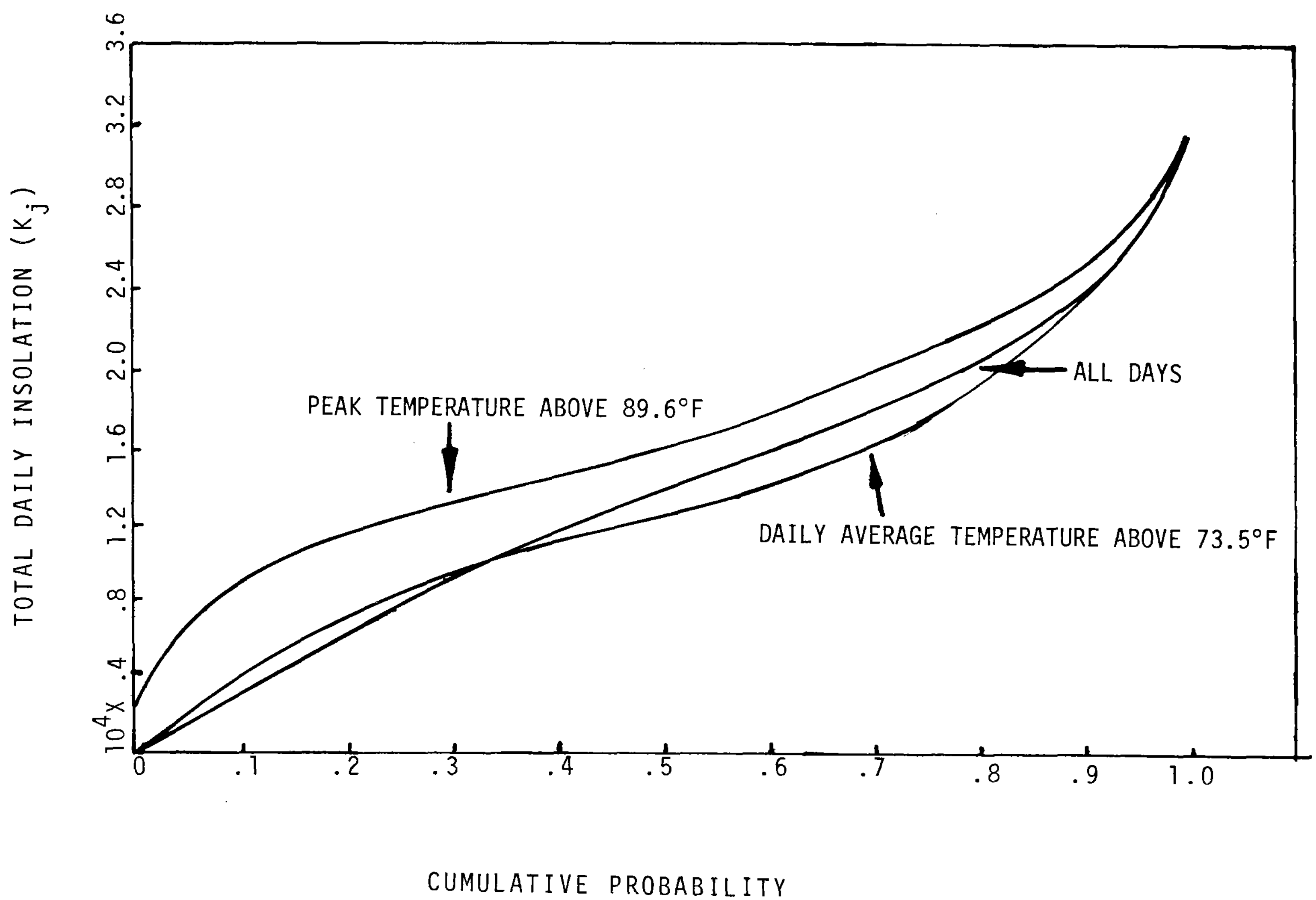


FIGURE 7

TABLE III

RELIABILITY PERCENTAGE FOR SOLAR PLANT IN MIAMI, FLORIDA

	High (25%)	Low (10%)	
Low (5%)	54%	86%	33% LOAD
	77%	91%	6% LOAD
High (10%)	46%	69%	33% LOAD
	63%	72%	6% LOAD

Percentage of Maximum Insolation Required for Operation

VII. Locations with Similar Annual Insolation: Miami and Madison

Miami and Madison are two locations of comparable annual direct normal insolation, averaging 2.077 and 2.059 x 10^4 Kj daily respectively (Ref. 3). In this section, each is examined for reliability of insolation when the system load is high. As high system load is experienced on days when consumers turn on air conditioners this analysis is restricted to those days on which the peak temperature is above 86°F (30°C) (although this is a simplification since humidity is also a factor in air conditioning load and may be more of a problem in Miami than in Madison). Figures 8 and 9 indicate the performance of solar plants in these locations on days for which the peak temperature is greater than 86°F. Assuming that the solar plant cannot operate when the insolation is less than 25% of the daily maximum, the probability of that happening on a hot day is .2 in Miami but only .075 in Madison. In addition, there are roughly five times as many hot days in Miami than in Madison, so that the number of hot days of the year during which the solar plant is inoperable is 24 in Miami, but only 1.875 in Madison. The conclusion from this is that a solar plant functions on hot days more reliably in Madison than in Miami (of course, ignoring the performance of either plant on the coldest days of the year).

However, it must be cautioned that there are 121 days in a typical year in Miami for which the peak temperature is greater than 86°F but only 25 such days in Madison; in effect, therefore, this is a comparison of solar plant performance on 33% of the days of the year in Miami with only 6% of the days of the year in Madison. It is a fact that the percentage of those days of the year when solar plant operation is critical to meeting system load varies according to the utility, depending on such diverse

MADISON (1953 - 1974)

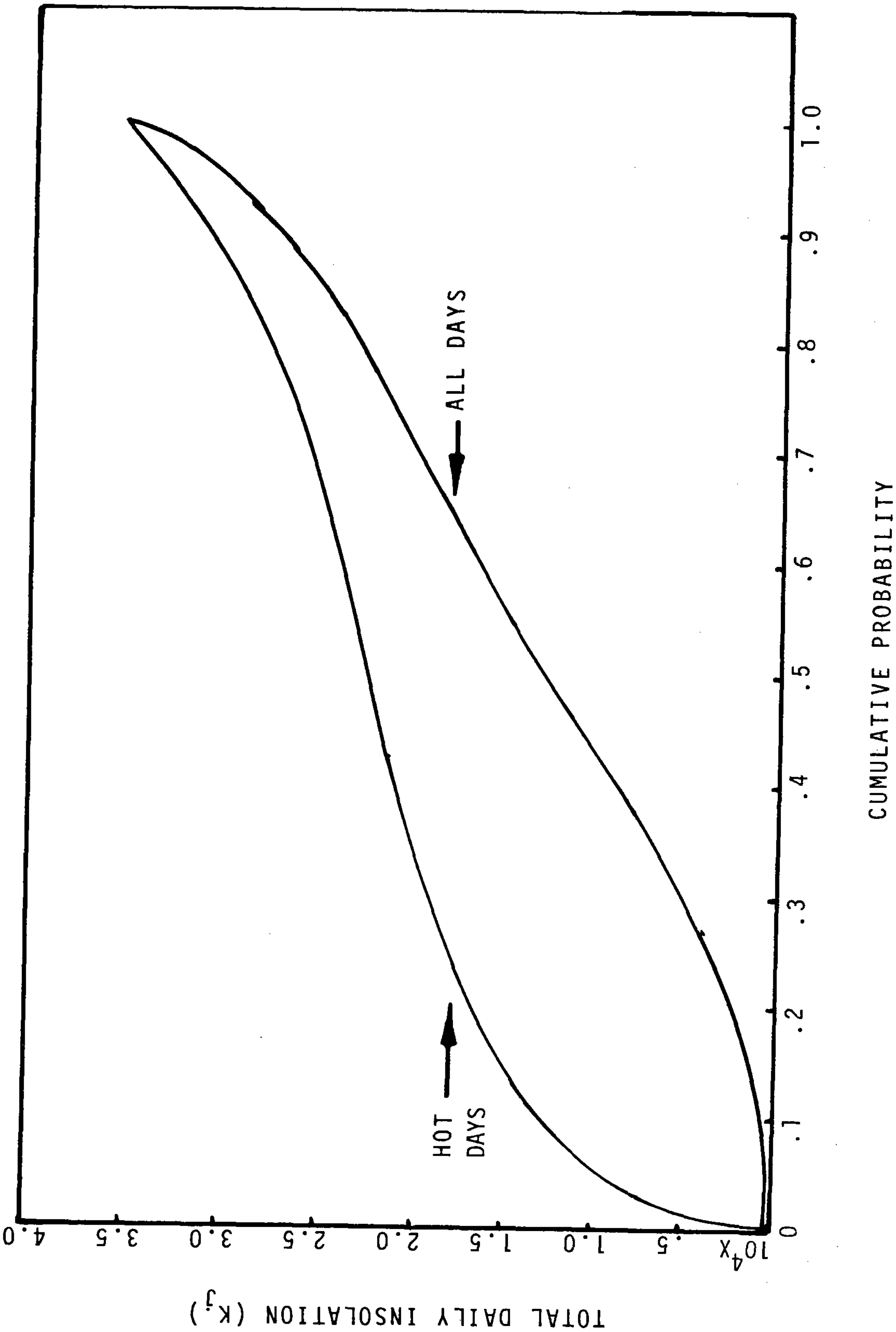


FIGURE 8

MIAMI (1953 - 1974)

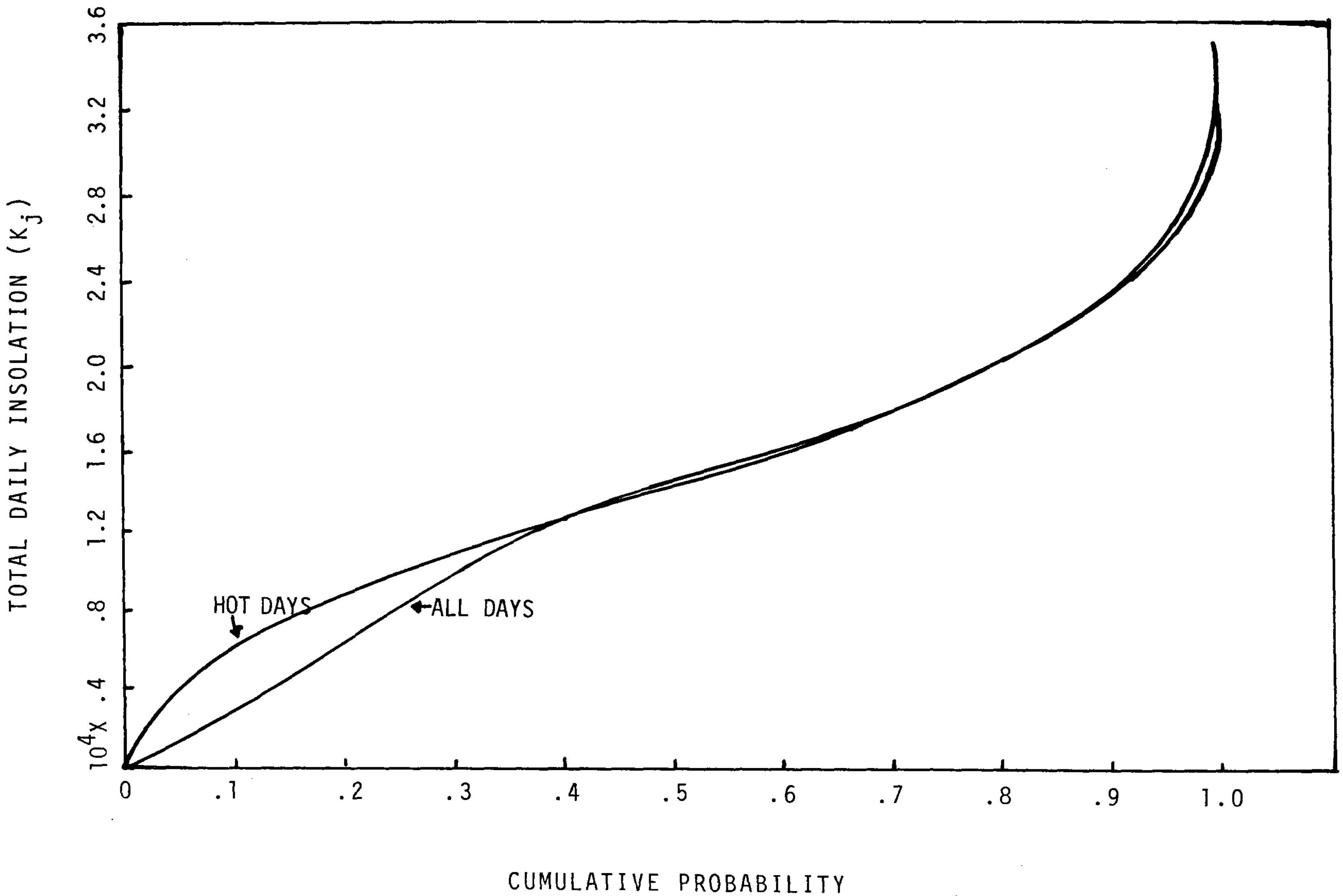


FIGURE 9

factors as the reliabilities of other plants in the grid and the shape of the system load curve. To understand this, consider Figure 10 in which System 1 differs from System 2 in that near peak demand is experienced for many more days of the year than in System 2; hence, if the remainder of the systems are comparable, it is expected that the solar plant will be required to operate many more days of the year in System 1 than in System 2. Returning to the case of Miami and Madison, the percentage of days of the year on which the daily load is greater than 90% of the respective system annual maximum is 12% for Miami compared to 6% for Madison (Figures 1 and 2).

Thus, instead of examining insolation at both sites on all days for which the peak temperature is above some specified value, insolation will be examined on the twelve percent hottest days in Miami versus the six percent hottest in Madison. Figure 11 is the probability distribution of direct normal insolation in Miami, Florida, for the 12% of the days with peak temperature above 88.25°F. Note that the probability that the insolation is less than .7 is .075 so that there are 3.29 days of a typical year on which the peak temperature is above 88.25°F and the solar plant may be shut down. By comparing the curve here with that of Figure 8, representing direct normal insolation on the hottest 6% days of the year in Madison, the conclusion is still seen to be that a solar plant in the latter location is almost twice as reliable on hot days (an outage rate of 1.88 days compared to 3.29 days). Of course, the difference in reliability is not as dramatic as was the analysis of insolation on days when the peak temperature is above 86°F, although both are based on 22 years of data for each site (53-74) and so are statistically significant, supporting the conclusion that it may be reasonable to expect a solar plant in Madison to be more reliable than one in Miami, at least on hot days.

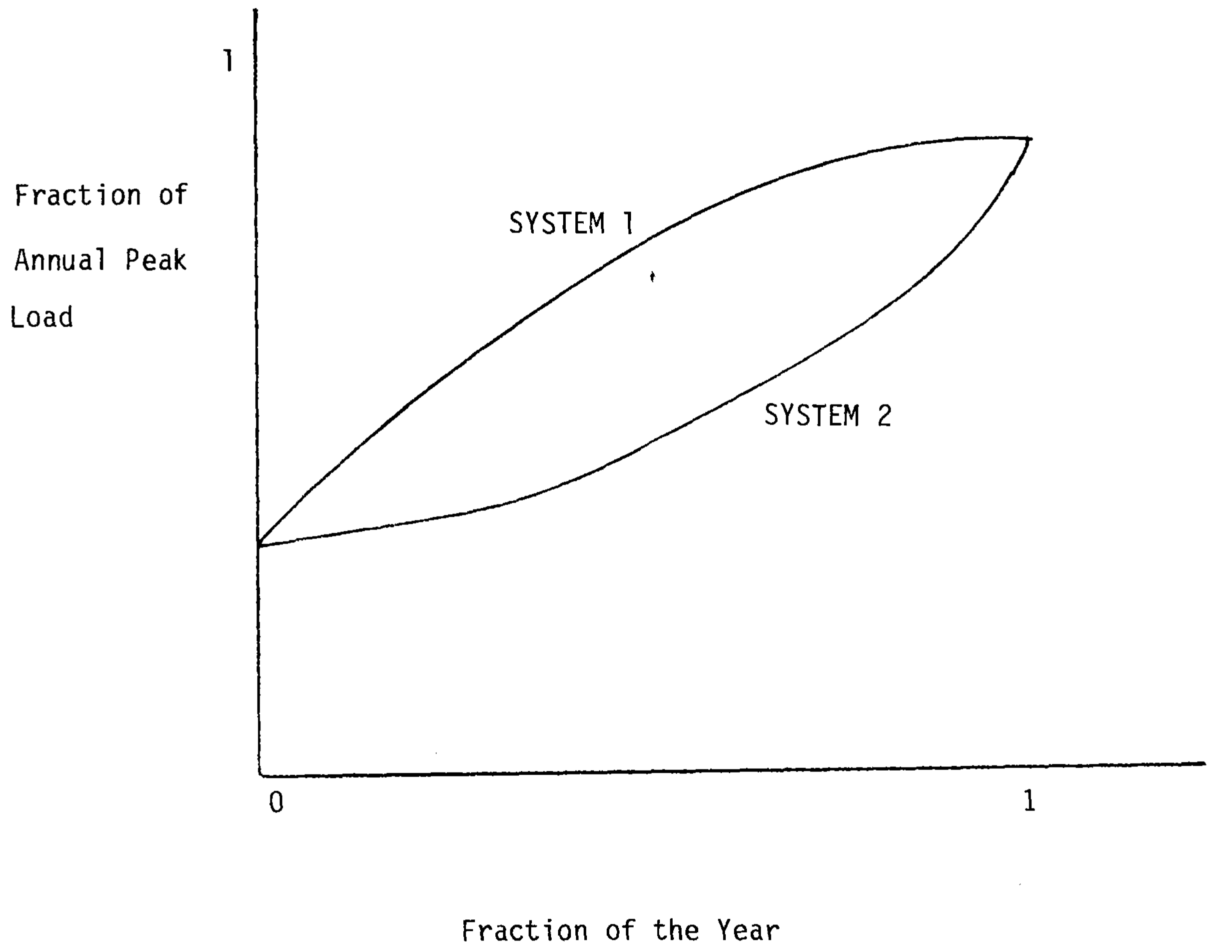

1
Fraction of
Annual Peak
Load
SYSTEM 1
SYSTEM 2
0
1
Fraction of the Year

Figure 10

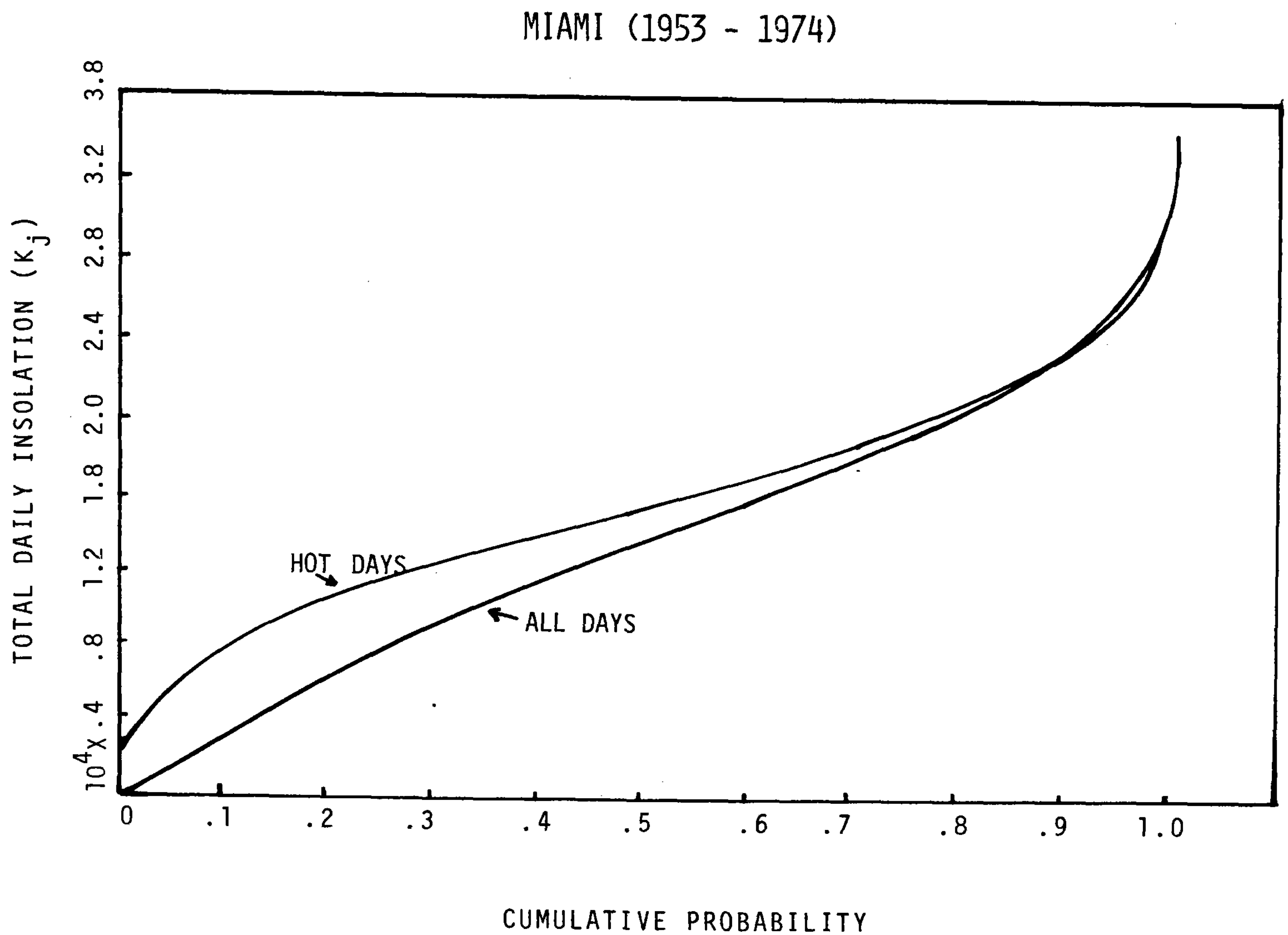
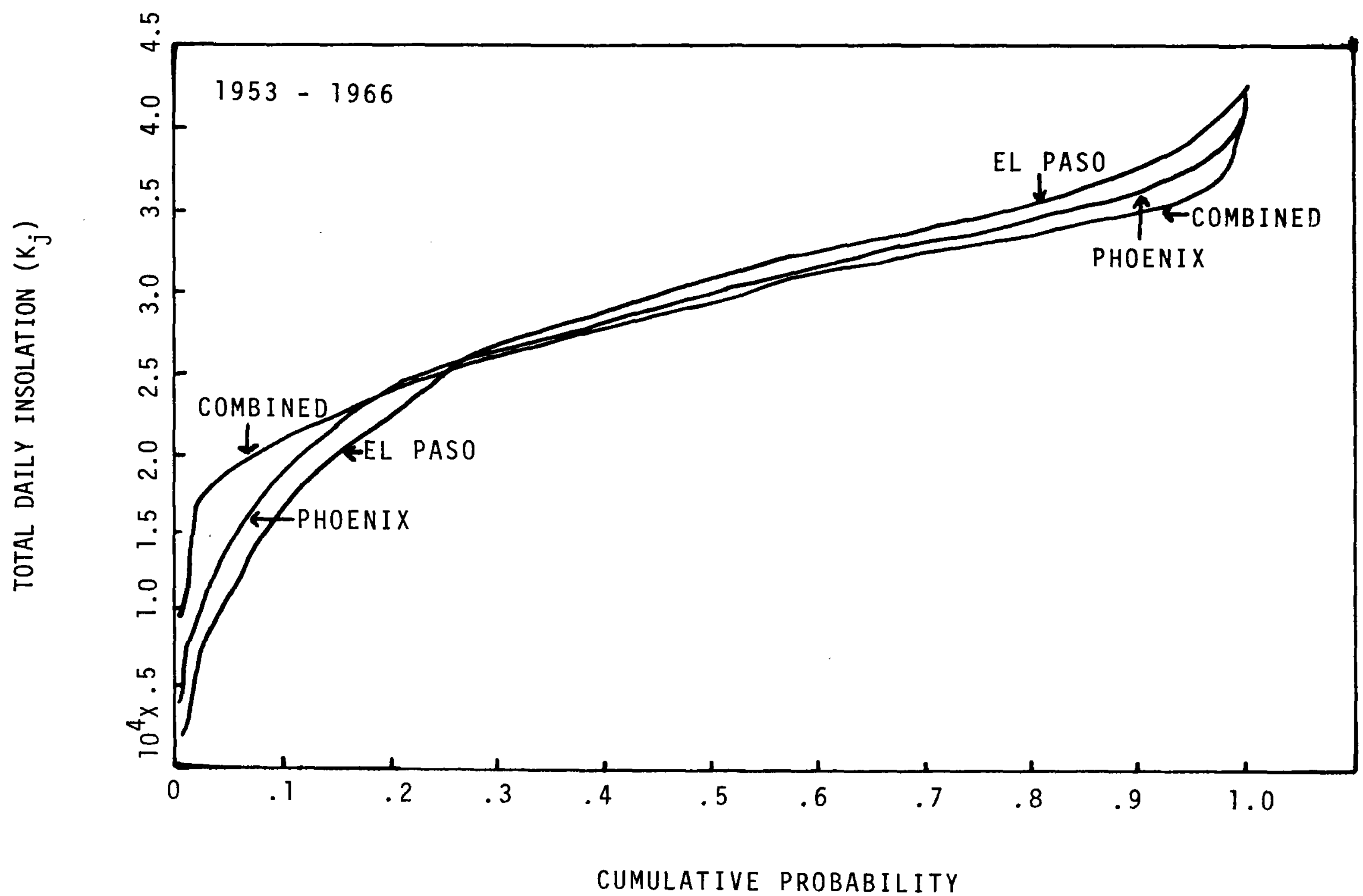

MIAMI (1953 - 1974)
TOTAL DAILY INSOLATION (K_j)
10^4X
.4
.8
1.2
1.8
2.0
2.4
2.8
3.2
3.8
HOT DAYS
ALL DAYS
0
.1
.2
.3
.4
.5
.6
.7
.8
.9
1.0
CUMULATIVE PROBABILITY

FIGURE 11

VIII. The Effect of Geographic Dispersion on Reliability: Phoenix and El Paso

It has been suggested that the reliability of solar plants in utilities can be improved by geographical dispersion. As an example, suppose a load is to be met in Phoenix. The choice may be to locate two solar plants in Phoenix, two in El Paso, or one in Phoenix and one in El Paso. The curves of Figure 12 represent the insolation seen by two solar plants, one located in El Paso and the other in Phoenix on days in Phoenix for which the peak temperature is greater than 86°F. Note that the insolation seen on a hot day in Phoenix by the plant in El Paso is less reliable than that seen by the solar plant in Phoenix, which is reasonable, since there is a positive correlation between temperature and insolation. The third curve labeled "combined" represents the total insolation seen by two solar plants, one sited in Phoenix and one in El Paso; note that this third curve is above the other two to the left of the scale, indicating that increased reliability is obtained by geographic dispersion; however, the "combined" curve is below the other two to the right of the chart, indicating a scarcity in days of simultaneous excellent insolation at both sites. By referring to Figure 12, note that the two plants in Phoenix will be inoperable (i.e., less than 25% of the maximum insolation) on roughly .025% of the hot days in Phoenix, as compared to roughly .005% for the dispersed plants; hence, the electricity generated by the dispersed system is roughly five times as reliable as that generated solely in Phoenix. Finally, note that electricity generated solely in Phoenix is roughly twice as reliable as that generated solely in El Paso (relative to hot days in Phoenix). Also, it can be seen that the total annual insolation is greater in El Paso than in Phoenix, although not significiantly as the ratio is 1.04 to 1. Hence there are a number of tradeoffs



1953 - 1966
TOTAL DAILY INSOLATION (K_j)
10^4X .5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
0
.1
.2
.3
.4
.5
.6
.7
.8
.9
1.0
COMBINED
EL PASO
PHOENIX
EL PASO
PHOENIX
COMBINED
CUMULATIVE PROBABILITY

FIGURE 12

possible as the following table illustrates, assuming that the load is in Phoenix:

Value To Phoenix Load (Based on Unity)

Location	Generation	Reliability (on hot days)	Proximity to Load
Phoenix	.957	.2	1.
El Paso	1.	.1	.25
Phoenix and El Paso Combined	.979	1.	.5

A "1" in a particular column designates the best location with respect to that variable. Numbers less than 1 indicate the degree to which that location fails to be optimal. What remains is to compare the cost of generation, reliability, and transmission to determine the optimal siting of the two solar plants.

If the choice is to either place both plants in Phoenix or both in El Paso, then the greater cost of generation in the former location must be traded-off with the cost of transmission and the loss in reliability in the latter location. Since the increased cost of generation in the former site is less than 10% and since transmission costs are more significant than that (Ref. 2), it is reasonable to conclude that for these sites of roughly comparable total insolation, siting near the load is favored. So, the final choice is to site both plants in Phoenix or one in Phoenix and one in El Paso; in the first instance, you pay more to generate with less reliability, whereas in the second instance, you pay for transmission.

What does transmission cost? The consumer must absorb the expense in building and maintaining the transmission lines connecting Phoenix and El

Paso, which are significant, as, historically, transmission costs have accounted for roughly one-third of the total cost of providing electricity to the consumer. In addition, the most optimistic view is that advances in high voltage technology will reduce electrical losses in transmission to .5% per 100 miles, and since the distance between Phoenix and El Paso is roughly 400 miles, electrical losses are on the order of 2%; hence, these losses nearly cancel the generational advantages of the El Paso site. So, to insure reliability, the final tradeoff seems to be between the capital cost of transmission lines versus that of a back-up plant.

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