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Final Report

DEFINITION STUDY FOR

PHOTOVOLTAIC RESIDENTIAL PROTOTYPE SYSTEM

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16 Abstract

The study consisted of the following tasks: site selection, parametric sensitivity study, conceptual design of the photovoltaic residential prototype system test (PST); preparation of test plan and procedures, and identification and examination of institutional problems.

The main effort was directed at the parametric sensitivity study and definition of the conceptual design. A computer program containing the solar irradiance, solar array, and energy balance models was developed. Using this program, analyses were conducted to determine the sensitivities of solar insolation and the corresponding solar array output at five sites selected for this study as well as the performance of several solar array/battery systems. Based on the results of this analysis, a baseline electrical configuration was chosen and three design options were recommended. The study indicated that the most sensitive parameters are the solar insolation and the inverter efficiency. A key result of the sensitivity analysis was that a significant increase in the overall PST efficiency can be obtained by eliminating the battery.

The baseline PST selected is comprised of a $133m^2$ solar array, 250 ampere-hour battery, one to three inverters, and a full shunt regulator to limit the upper solar array voltage. A mini-computer controlled system is recommended to provide the overall control, display, and data acquisition requirements. Architectural renderings of two photovoltaic residential concepts, one above-ground and the other underground, are presented.

The institutional problems were defined in the areas of legal liabilities during and after installation of the PST, labor practices, building restrictions and architectural guides, and land use.

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FOREWORD

The following NASA, MMC, and subcontractor personnel contributed to this study and in the preparation of this report: Mr. William Bifano, LeRC Project Manager, for his detailed review and comments; Mr. Brooks Waldman and Mr. Rod Lane of Brooks Waldman Associates for the architectural renderings of two PST configurations; Mr. Ed Buchanan and Mr. A. Salim for power processing equipment design and analysis; Mr. Dean Schneebeck for the preparation of test plan and procedures; Mr. Jim Masson and Mr. Clip Cookson for system design and analysis; and Mr. John Sanders for overall review. Mr. Roland Hulstrom performed all solar irradiance work. Mr. Matthew Imamura was the MMC Program Manager.

SUMMARY

This study consisted of the following tasks: site selection analysis, parametric sensitivity study, conceptual design of the photovoltaic residential prototype system test (PST), preparation of test plan and procedures, and the identification of institutional problems.

In the study to define potential sites for the photovoltaic residential PST, the continental United States was divided into nine geographical regions. Each region was rated and ranked numerically. The rating criteria were based on factors such as climate, insolation, population, population density, growth and power/energy demand characteristics. Three potential sites were then identified in each region based on a constraint that the site be located on federally owned, non-Department of Defense (DOD) property. Because of problems in locating sufficient candidate sites on federal non-DOD land, it is recommended that future site selection studies include the consideration of state-owned land.

The parametric sensitivity analysis was conducted to evaluate several power system configurations and select a baseline configuration. The performance of the baseline configuration was analyzed for five sites (Cleveland, Ohio; Gainesville, Florida; Blue Hill, Massachusetts; Denver, Colorado; and Phoenix, Arizona). These sites were selected by NASA-LeRC to provide a range of climatological conditions and power requirements for defining the photovoltaic residential PST. The selections do not imply that these locations represent future sites for the PSTs.

A computer program was written and used in the parametric sensitivity analysis. This program consists of solar insolation, solar array, energy balance, and electrical load models. The analysis revealed that the power system configuration containing only the solar array, inverter, shunt regulator, and associated control circuitry (i.e., without energy storage battery) is the simplest and the most cost-effective photovoltaic system for general residential application. However, for experimental purposes and to satisfy the overall objectives of the PST, use of a battery in the PST program is recommended. The main benefits of the configuration without the battery as compared to that with the battery are as follows:

(1) It provides a significantly higher annual energy displacement and available power for the same solar array area.

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(2) For a given annual energy displacement and solar insolation level, solar array size can be reduced by a factor of two or more resulting in a substantial cost saving.

(3) It has a substantially higher overall power system efficiency.

(4) Maintenance and safety problems are minimized.

Solar insolation, electrical power demand, and inverter efficiency were identified as the most sensitive parameters affecting the PST performance. With the present inverters and their power conversion efficiency characteristics the use of several inverters of various ratings was found to be necessary to minimize losses and achieve a high power system efficiency over widely varying electrical load demand conditions of a typical residence.

As part of the conceptual definition of the PST, architectural renderings of the residential PST were developed by an architectural engineering firm. Underground and above-ground concepts were examined. The principal benefit of the underground concept is in energy conservation by minimizing heat loss and maximizing environmental control capability. The main drawback is in the uncertainty of public acceptance in underground living.

Two basic options of the power system configuration are recommended for the PST experiment, one with and one without the battery. The PST without the battery requires an inverter with the capability to operate the solar array at its peak power point and feed power to the utility grid. Development is required to provide this inverter and its associated control circuitry.

The required array size is determined mainly by the available insolation and array/battery energy balance period (i.e., 1-day, 2-day, etc.). Therefore, rather than determine the array area required for various sites, general sizing criteria were described. For the purpose of this study, a 133 m^2 (1,500 ft^2) array was used. The recommended array configuration for the PST program is a sawtooth design with good access to the solar array modules for maintenance.

Potential institutional problems associated with the implementation of the photovoltaic residential PST were defined. These were in the areas of legal liabilities during and after installation of the PST, labor practices, building restrictions and architectural guides, and land use. The key technical and legal problem appears to be in the PST power system-to-utility grid interface. Additional studies are recommended to determine methods of satisfying the interface requirements and constraints of the local utility industry.

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1.0 INTRODUCTION

The primary objectives of this study were to determine the information needed for implementing the residential photovoltaic prototype system test (PST) program and to define and configure an appropriate PST to provide that information. This included the definition of a test plan, test equipment required, and test procedures.

The secondary objectives were to: (1) select eight regions in the continental United States, rate them as potential residential PST sites, and identify three sites for each region; and (2) identify and examine institutional problems.

The PST is an experiment intended to provide the necessary information so that more intelligent design selections can be made in subsequent tests and analyses. It is therefore not intended to be a demonstration system for the final residential photovoltaic power system, and not a verification of an optimum design.

This study consisted of the following tasks:

Task I - Site Selection Study
Task II - Parametric Sensitivity Analysis
Task III - Conceptual Design of Residential PST
Task IV - Test Plan
Task V - Test Equipment Requirements and Test Procedures
Task VI - Identification and Examination of Institutional Problems

As a part of Task II, a computer program was required to be developed and used in generating the sensitivity data.

The basic constraints and guidelines for this study were as follows:

(1) For the site selection study (Task I), the identification of potential PST sites on non-Department of Defense, federally owned land in each of eight regions was to be made without contacting the agency involved.

(2) The parametric sensitivity data (Task II) were to be developed for the following five locations in the United States:

Blue Hill, Massachusettes; Cleveland, Ohio; Denver, Colorado; Gainesville, Florida; and, Phoenix, Arizona.

(3) LeRC was to furnish the solar cell and module output characteristics for use in the solar array design and performance analysis (Tasks II and III).

(4) Only the solar electric system was to be considered. That is, a combined solar electric-thermal conversion system was not to be considered.

2.0 TASK I - SITE SELECTION STUDY

2.1 Introduction and Summary

The purpose of this study was to identify potential sites, located on federally-owned, non-DOD property, for the Residential Prototype System Test (PST). In order to accomplish this, the continental United States was divided into nine geographical regions or divisions. Each division was then rated as a potential PST location, according to criteria which reflected such parameters as climate, insolation, population and population density, growth, power/energy characteristics, and public visibility. Martin Marietta then selected three sites in each geographical division that would be representative of conditions in that division.

The Mountain region received the highest rating, while the West North Central region obtained the lowest rating because of low scores in almost all categories. The numerical ranking score indicated that the nine regions can be qualitatively divided into three groups rated as good, fair, and poor in terms of their attractiveness as potential PST sites:

Group I	Qualitative Rating
Mountain South Atlantic Pacific	Good
Group II	
East North Central East South Central West South Central	Fair
Group III	
New England Middle Atlantic West North Central	Poor

The *National Atlas* and the *Federal Telecommunications System Users Guide* were used in determining federal land and sites. For some sites, even state-owned land as well as federal, (non-DOD) lands could not be readily located. Because a problem exists in locating sufficient candidate sites on non-DOD federal land, it is recommended that future studies of this type include state-owned land.

2.2 Geographical Regions of the Continental United States

The geographical regions or divisions selected for this study are shown in Figure 2-1. These divisions are commonly used by the U.S. Department of Commerce, Bureau of Census, the Federal Power Commission, and the Department of Interior. Statistics published by these agencies are given according to these nine divisions. Since these statistics were extensively used in this study, it was advantageous to use the same nine geographic divisions. The only statistical modification required for this study was to remove Alaska and Hawaii from the Pacific division. This resulted in a division entitled Pacific Contiguous States. The divisions and the states making up each division are listed, along with their size in Table 2-1.

For information, the nine geographical divisions were grouped into four regions of the United States to show the relative size of these regions (see Table 2-2).

2.3 Geographical Regions Selection Criteria

Criteria were formulated and a rating system was derived in order to rate each geographical division as a potential site for a residential PST.

The criteria formulated consisted of the following parameters:

(1) Climate - humidity (annual mean), precipitation (annual, inches), thunderstorms (annual number of days of), tornadoes (frequency of), wind (maximum expected), temperature extremes (annual low-annual high);

(2) Insolation - mean daily, annual, Langleys;

(3) Population - number, density, 1973;

(4) Growth - percent increase from April 1, 1970 to July 1, 1973;

(5) Energy/power characteristics - fossil fuel energy consumed versus produced, installed generating capacity versus total sales;

(6) Public visibility - combination of available insolation, energy/power characteristics, population number/density, and growth;

(7) Insolation versus power demand profile (monthly) versus available solar insolation.

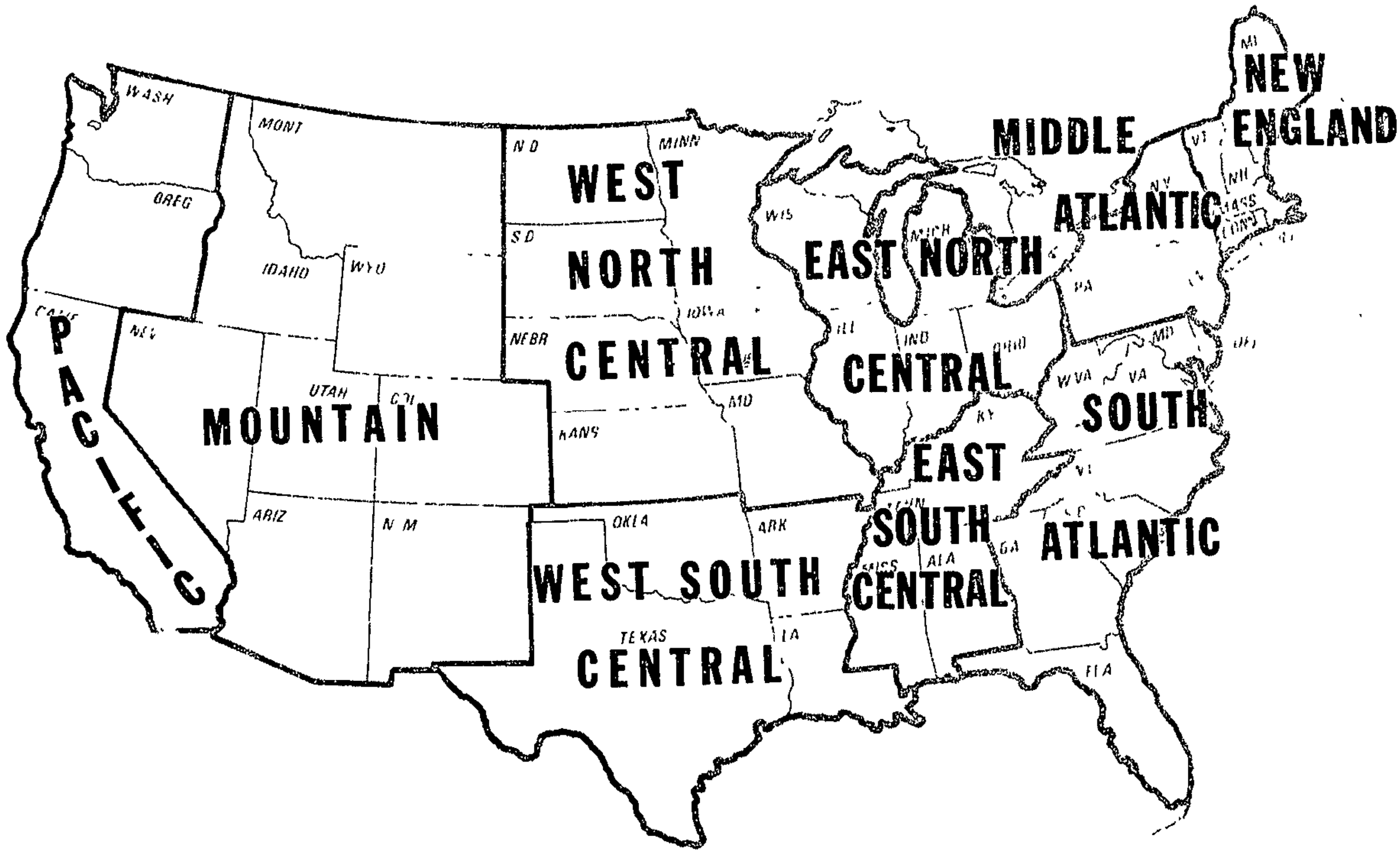


Figure 2-1 Geographical Divisions of the United States

Table 2-1 Geographical Divisions and States

Geographical Division	States	Area, sq.mi.	Relative Area, %
I New England (N.E.)	Maine New Hampshire Vermont Massachusetts Rhode Island Connecticut	66,608	2 20
II Middle Atlantic (M.A.)	New York New Jersey Pennsylvania	102,745	3.40
III East North Central (E.N.C.)	Ohio Indiana Illinois Michigan Wisconsin	248,283	8 22
IV. West North Central (W.N.C.)	Minnesota Iowa Missouri North Dakota South Dakota Nebraska Kansas	517,247	17.11
V. South Atlantic (S.A.)	Delaware Maryland District of Columbia Virginia West Virginia North Carolina South Carolina Georgia Florida	278,776	9 22
VI. East South Central (E.S.C.)	Kentucky Tennessee Alabama Mississippi	181,964	6.03
VII West South Central (W.S.C.)	Arkansas Louisiana Oklahoma Texas	438,884	14.52
VIII. Mountain (M)	Montana Idaho Wyoming Colorado New Mexico Arizona Utah Nevada	863,887	28 58
IX. Pacific (P)	Washington Oregon California	323,866	10.72

Table 2-2 Geographical Regions of United States

Geographical Region	Geographical Div.	Region Area, %
I. Northeast	New England Middle Atlantic	5.60
II. South	South Atlantic East South Central West South Central	29.77
III. North Central	East North Central West North Central	25.33
IV. West	Mountain Pacific	39.30

Climate. The climate parameters were selected to indicate the general attractiveness of the climate of the various regions relative to the PST program. For example, a climate consisting of high humidity, precipitation, frequency of tornadoes, winds, and large temperature extremes would obviously be unattractive compared to climates having less extreme conditions. The numerical system used for these climate factors is listed below.

Factor	Score
Humidity	0 to 1
Precipitation	0 to 1
Thunderstorms	0 to 2
Tornadoes	0 to 2
Wind	0 to 2
Temperature Extremes	0 to 2

Note: (0) lowest score
(2) highest score.

The total climate numerical score was then weighted by a factor of 5, as discussed later. The product of the climate numerical score and the climate weighting factor determined the climate rating (0 to 50 points) of the geographical division. Data for the climate parameters were taken from the *National Climatic Atlas*.

Insolation. The insolation parameter was selected to indicate the level of solar insolation available to the PST in a given geographical division. A rating for insolation was derived by determining the geographical divisions typical annual insolation, in Langleys, from the *National Climatic Atlas*. Accordingly, a numerical score was assigned ranging from 5 to 10. This numerical score was then weighted (multiplied by a factor of 10) to determine the final rating (ranging from 50 to 100 points).

Population. The population parameter was selected to indicate the general total potential market for the photovoltaic residential application in a given geographical division. This was based upon the logic that a higher population would result in a greater number of solar photovoltaic residential systems (SPCSs) creating greater savings of fossil fuel, thereby making them attractive.

The population density parameter was selected to indicate the degree to which SPCSs could be incorporated in a given geographical division. A low population density would allow the SPCSs to be more easily incorporated into an area because of fewer numbers of buildings/people per square mile; and, because new housing developments, in which SPCSs could be more easily employed, would more likely occur in areas of low population density.

Both the population and population density were given a numerical score of 0 to 5. The sum of these numerical scores was then weighted by a factor of 5 to derive the final rating (0 to 50) of each division. The population and population density data were obtained from the *Statistical Abstract of the United States*, 1974, U.S. Dept. of Commerce, Bureau of the Census.

Growth. The growth parameter was selected because it is indicative of the potential for future application of photovoltaic systems on new homes. Each region was given a numerical score from 5 to 10. This score was then weighted by a factor of 5 to obtain the final rating (25 to 50 points).

Energy/power. An energy/power rating was derived for each division to determine the degree of usefulness the SPCS could have in terms of aiding each divisions power and/or energy situation. The power adequacy of each division was determined by calculating the ratio of installed generating capacity to total sales in kilowatt hours. This parameter is indicative of power reserve. Data for this parameter were taken from the U.S. Federal Power Commission annual summaries and monthly reports as published in the U.S. Bureau of the Census, *Statistical Abstract of the U.S.:* 1974 (95th Edition) Washington, D.C., 1974. Each division was then given a numerical score from 0 to 5 for power adequacy. The energy adequacy was determined by calculating the ratio of energy consumed (all fossil fuels) to energy produced (fossil fuels). This ratio is indicative of the dependence upon external energy sources by a geographical division. Data for this ratio were obtained from the Department of the Interior, *United States Energy Fact Sheets*, 1971, Office of the Secretary, Washington, D.C. Each division was given a numerical score of 0 to 5 for its energy adequacy ratio. The total rating for each divisions energy/power adequacy was determined by multiplying the sum of the power and energy adequacy numerical scores by a weighting factor of 7 (total range 0 to 70 points).

Public/visibility. The public visibility parameter was selected to determine each geographical division's potential for attractively displaying the national effort being applied to the residential SPCS and its potential benefits concerning the energy problem. This parameter was formulated from a combination of the insolation, power/energy adequacy, population/population density, and growth factors.

The insolation parameter was included because the output of the SPCS is directly proportional to the insolation level. The power/energy adequacy parameter was included because the SPCS would have greater visibility if it was located in an area that has a power/energy problem. The population/population density parameters were included because the SPCS would have greater visibility if it was located in a geographical division having a high population resulting in a greater amount of potential energy savings, and where the population density was such as to allow the SPCS to be easily incorporated (low density). The growth parameter was included because a high growth rate would give the SPCS greater visibility since it could be more easily incorporated in the new growth developments.

The total numerical score for the public visibility parameter was determined by assigning a score of 0 to 4 for the insolation rating, 0 to 2 for the power/energy adequacy rating, 0 to 2 for the population/population density rating, and 0 to 2 for the growth rating. This made a total of 0 to 10 possible for the numerical rating. This numerical score was then multiplied by a weighting factor of 10 to determine the final rating for public visibility (0 to 100 points).

Solar insolation versus power demand profiles. This parameter was seldcted to establish a comparison between the available solar insolation profile (monthly) versus the power demand profile (monthly). The solar insolation monthly profile was generated from data in the *National Climatic Atlas;* the residential power demand profile was taken from *Mission Analysis of Photovoltaic Solar Energy Systems,* (prepared by the Aerospace Corporation for the National Science Foundation, RANN, NSF Grant GI-44099, Report: NSF/RANN/SE/GI-44099/PR/74/4). This demand profile represents the seasonal residential power demand for the United States.

The detailed solar insolation versus power demand monthly profiles are given in section 2.4. The power demand profile used is typical for the entire United States; therefore, it is not exactly representative of any given geographical division. In addition, the solar insolation profiles are representative of an entire geographical division. However, within any given division there can be a wide variation in solar insolation. A good example of this is the Mountain division which includes the hot, dry, sunny climate of the southwest states (Arizona, etc.) in contrast to the cold, wet, cloudy climate of the northern states (Montana, etc.). Examples of the variation in divisional power demand profiles are shown in Figure 2-2.

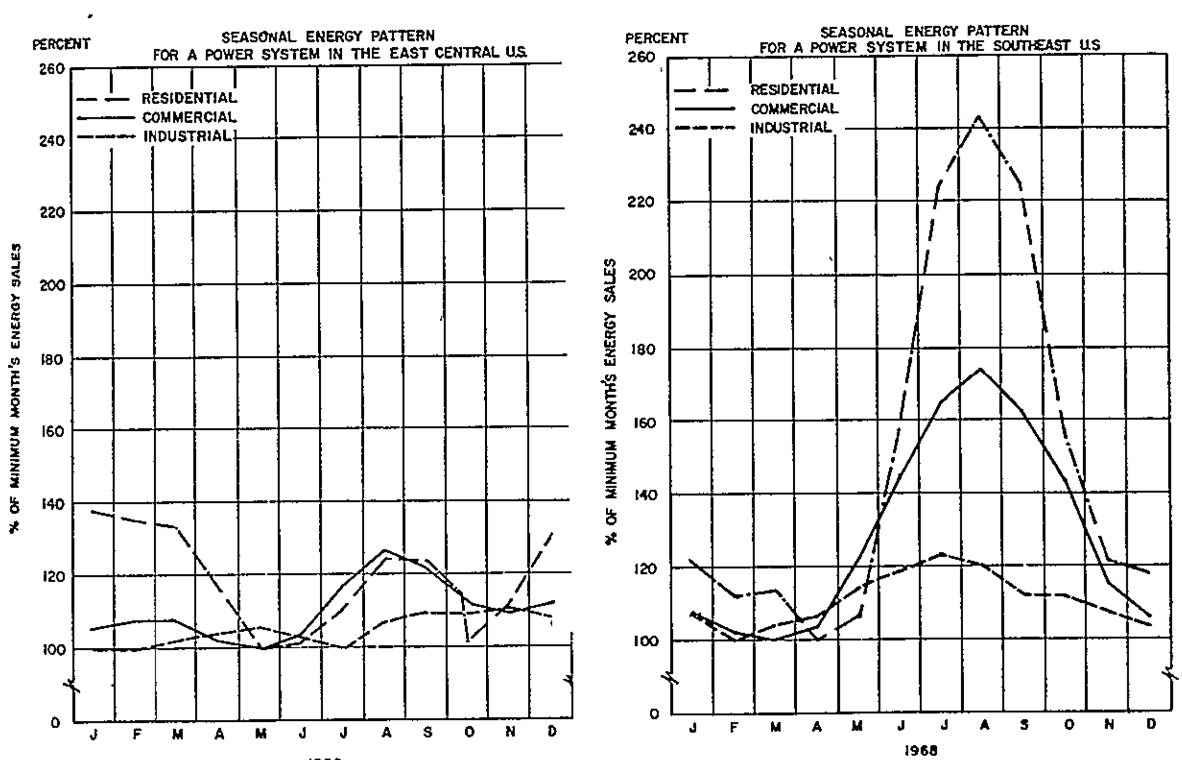


Figure 2-2
Examples of Variation in Power Demand for Different Geographical Divisions

From a comparison of the divisional power demand profiles with the United States profile, it can be concluded that the prevailing characteristic shown by all curves is that peaks occur during the summer and winter seasons. In the warm climate southern states, this will be changed somewhat due to a much less pronounced peak during winter and a very pronounced peak during summer. Therefore, the United States power demand profile used in this study is representative of the general nature of the general characteristics of the power demand profile. From the monthly solar insolation profiles, it can be seen that the level of insolation varies with geographical division, but the general nature of the solar insolation profile is nearly the same for all divisions, characterized by a summer peak. Therefore, although more detailed solar insolation profiles are desired, they would most likely display the same general profile as the more general ones used in this study.

In order to generate a rating for each geographical division in terms of the solar insolation versus power demand profile, these profiles were plotted on a monthly basis. Each division was then given a numerical score indicative of the match between the solar versus power profiles. This score was broken down in three categories: (1) good, 10 points; (2) fair, 7 points; and (3) poor, 5 points. This numerical score was then weighted by a factor of 10 to determine the final rating (50 to 100 points).

2.4 Weighting Factors and Numerical Scores

The weighting factors and possible numerical scores for each criteria parameter are listed in Table 2-3.

The purpose of the weighting factor was to assign a relative importance to each of the parameters. Table 2-3 shows that the highest degree of importance was assigned to the insolation, public visibility, and solar insolation versus power demand parameters. It was felt that these three parameters are critical to success of the SPCS. The next highest importance was assigned to the energy/power parameter, and the lowest importance was assigned to the climate, population, and growth parameters.

2.5 Geographical Region Selection Results

The results of numerical scoring for each of the geographical regions are summarized in Tables 2-4 through 2-9 for the climatic conditions, insolation, population and population density, growth, and energy/power.

Table 2-3 Numerical Scores and Weighting Factors

Parameter	Numerical Score	Weighting	Possible Rating
Climate	0 to 10	5	0 to 50
Insolation	5 to 10	10	50 to 100
Population Amount Density	 0 to 5 0 to 5	5	0 to 25
Growth	5 to 10	5	25 to 50
Energy/Power Adequacy Energy Power	 0 to 5 0 to 5	7	0 to 35
Public Visibility	0 to 10	10	0 to 100
Solar Insolation vs Power Demand	5 to 10	10	50 to 100
		Total	125 to 460

The solar insolation profiles for the geographical divisions and a generalized national power demand profile are shown in Figures 2-3 and 2-4. As can be seen, all the solar insolation profiles are similar although the levels of insolation vary. Therefore, in general, the insolation profiles are different from the power demand profile because the insolation profiles peak during the summer months. However, if individual power demand profiles for the geographical division (see Fig 2-2) is considered, there is a much better match between the solar insolation and power demand profiles for the geographical divisions having southern states, where a much less pronounced peak in power demand would occur during the winter months. This consideration has been given in the numerical scores of the divisions for this parameter.

As discussed previously, each division was given a rating of 10 (good), 7 (fair), and 5 (poor) points. The divisions having predominantly northern states and low insolation values were given a poor rating because of the poor match between solar insolation and power demand profile (as discussed above). The divisions having a mixture of northern and southern states (Mountain divisions) were given a fair rating. The divisions having predominantly southern states (South Atlantic division) were given a good rating. The results of all scores are shown in Table 2-10.

Table 2-4 Rating of Climatic Conditions

Geographic Division	Humidity		Precipitation		Thunderstorms		Tornadoes		Wind		Temperature Extremes		Total
	Annual Mean, %	Score (0-1)	in., yr	Score (0-1)	day, yr	Score (0-2)	Freq	Score (0-2)	mph, max	Score (0-2)	F°	Score (0-2)	
NE	70-80	0	32-48	0	10-30	2	Med	1	70-80	1	(-30) +100	1	5
MA	70-80	0	32-48	0	30-40	1	Med	1	70-80	1	(-20) +100	1	4
ENC	60-80	0	24-40	0	30-50	1	High	0	70-90	1	(-30) +100	1	3
WNC	60-80	0	16-40	1	30-60	0	High	0	70-80	1	(-40) 110	0	2
SA	60-80	0	32-64	0	40-90	0	Med	1	60-90	1	(-20) 100	1	3
ESC	70-80	0	48-64	0	50-70	0	Med	1	60-80	1	(-10) 100	2	4
WSC	50-70	0	16-48	1	30-70	0	High	0	60-90	1	(-10) 105	2	4
M	20-80	1	8-32	1	10-70	1	Low	2	70-100	0	(-40) 110	0	5
P	20-90	1	8-48	1	0-30	2	Low	2	0-90	2	(-30) 110	0	8

NE	New England
MA	Middle Atlantic
ENC	East North Central
WNC	West North Central
SA	South Atlantic
ESC	East South Central
WSC	West Sounth Central
M	Mountain
P	Pacific

Table 2-5 Insolation Rating

Geographic Division	Isolation	
	Mean Daily, Langleys	Score, 5 to 10
NE	200 to 350	5
MA	200 to 350	5
ENC	300 to 400	6
WNC	300 to 400	6
SA	300 to 500	7
ESC	300 to 500	7
WSC	400 to 500	8
M	300 to 600	10
P	300 to 500	7

Table 2-6 Population and Population Density Rating

Geographic Division	Population		Population Density		Total
	Thousands	Score, 0 to 5	People/sq.mi.	Score, 0 to 5	
NE	12,151	2	193	2	4
MA	37,528	4	374	1	5
ENC	40,897	5	168	2	7
WNG	16,704	2	33	3	5
SA	32,459	4	122	2	6
ESC	13,289	2	74	3	5
WSC	20,257	3	47	3	6
M	9,149	1	11	5	6
P	26,255	1	81	3	6

Table 2-7 Growth Rating

Geographical Division	Growth	
	% Increase	Score (5-10)
NE	0.8	6
MA	0.3	5
ENC	0.5	5
WNC	0.7	6
SA	1.7	7
ESC	1.1	6
WSC	1.4	7
M	3.1	10
P	1.0	6

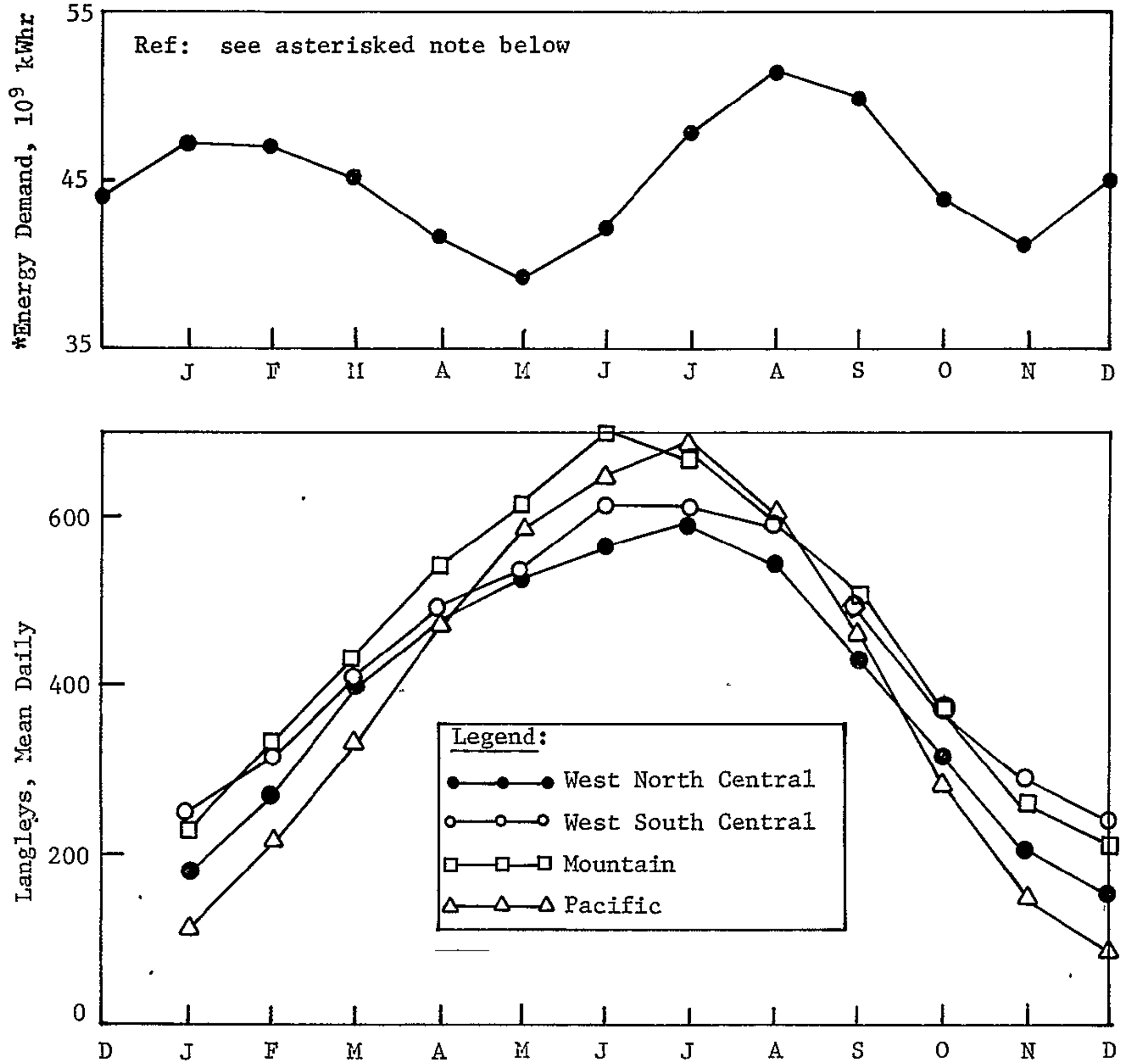
Table 2-8 Energy/Power Adequacy

Geographical Division	Consumption/Production		Capacity/Sales		Total
	Ratio	Score (0-5)	Ratio	Score (0-5)	
NE	∞	5	2.38	4	9
MA	4.43	4	2.39	4	8
ENC	3.56	4	2.16	5	9
WNC	2.48	3	2.45	4	7
SA	1.99	3	2.41	4	7
ESC	1.00	2	2.14	5	7
WSC	0.30	1	2.57	3	4
M	0.60	1	2.46	4	5
P	1.80	2	2.05	5	7

Table 2-9 Geographical Division Rating of the Four Most Critical Factors

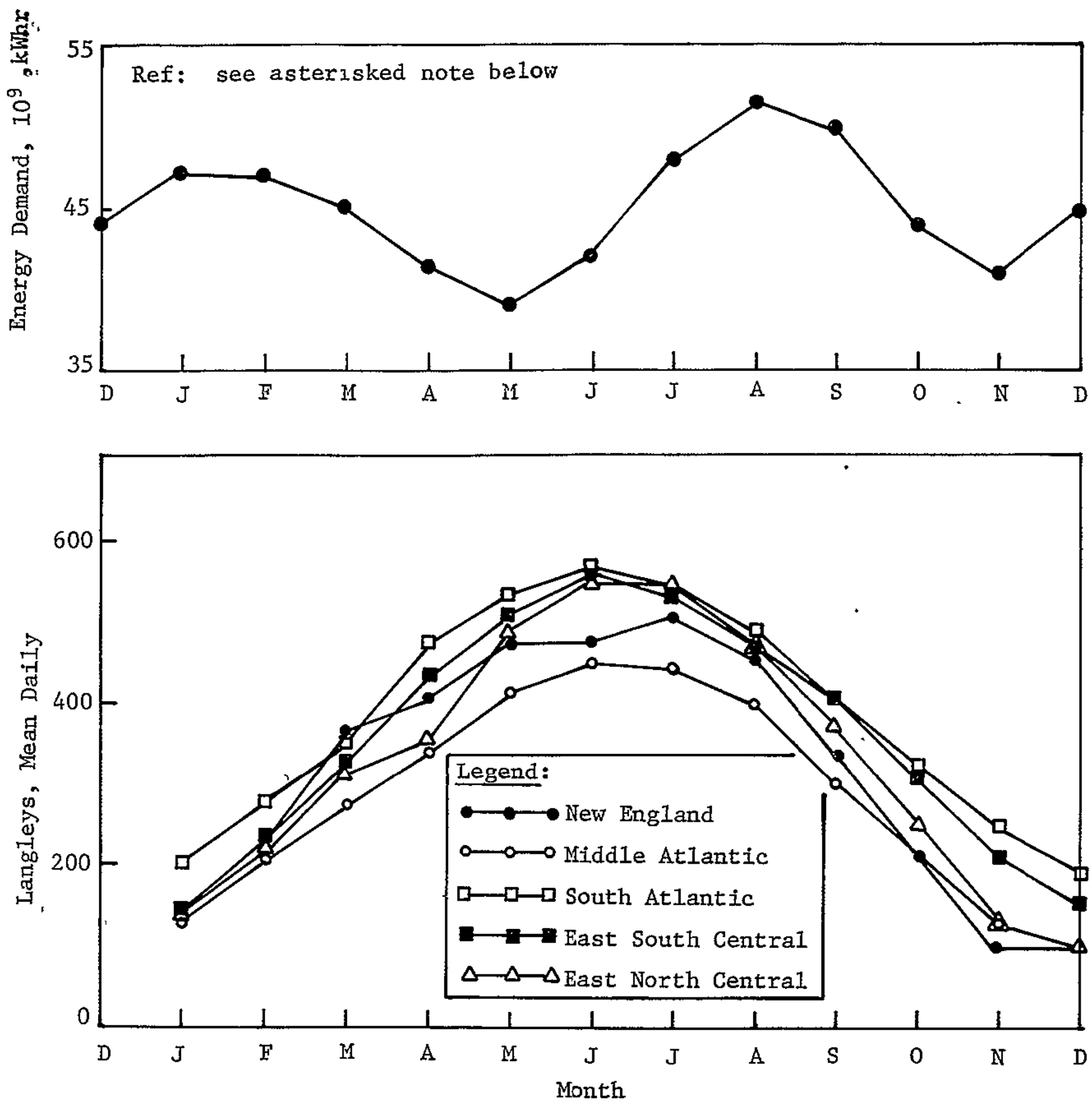
Geographical Division	*Insolation Score (0-4)	*Power/Energy Score (0-2)	*Population and Density Score (0-2)	*Growth Score (0-2)	Total
NE	1	2	1	1	5
MA	1	2	1	1	5
ENC	2	2	2	1	7
WNC	2	1	1	1	5
SA	3	1	2	1	7
ESC	3	1	1	1	6
WSC	4	0	2	1	7
M	4	1	1	2	8
P	3	1	1	1	6

*Values are shown in the previous tables.



**Seasonal Variation in Electric Energy Demand*, U.S. 1972, (Trend Removed) Aerospace Report No. ATR-75 (7476-01)-1, NSF Grant GI - 44099

Figure 2-3 Solar Insolation and Electric Energy Demand Profile (Monthly)



**Seasonal Variation in Electric Energy Demand*, U.S. 1972, (Trend Removed) Aerospace Report No. ATR-75 (7476-01)-1, NSF Grant GI - 44099

Figure 2-4 Solar Insolation and Electric Energy Demand Profile (Monthly)

Table 2-10 Solar Insolation Versus Power Demand Scores

Geographic Division	(Score 5 - 10)
NE	5
MA	5
ENC	5
WNC	5
SA	10
ESC	7
WSC	7
M	7
P	7

The numerical score for each geographical division was weighted (multiplied by the weighting factors defined in Section 2.3) in order to obtain a rating for each parameter. Table 2-11 summarizes the overall rating for each geographical division.

The Mountain division received the highest rating. This division scored high in the insolation, population/density, growth, and public visibility categories. The West North Central division received the lowest rating because of low scores in almost all categories. The percent ranking indicator reveals that the divisions can be grouped into the following three groups:

Group	Percent Ranking
I. Mountain South Atlantic Pacific	89 to 100
II. East North Central East South Central West South Central	82 to 85
III. New England Middle Atlantic West North Central	70 to 74

Table 2-11 Summary of Geographical Division Ratings

Geographical Division	Climate	Insolation	Population and Density	Growth	Power/ Energy Adequacy	Solar vs Power Demand	Public Visibility	Total	Percent Ranking,%	Numerical Ranking
M	25	100	30	50	35	70	80	390	100	1
SA	15	70	30	35	49	100	70	369	95	2
P	40	70	30	30	49	70	60	349	89	3
WSC	20	80	30	35	28	70	70	333	85	4
ESC	20	70	25	30	49	70	60	324	83	5
ENC	15	60	35	25	63	50	70	318	82	6
NE	25	50	20	30	63	50	50	288	74	7
MA	20	50	25	25	56	50	50	276	71	8
WNC	10	60	25	30	49	50	50	274	70	9

It is probably more realistic to consider these three groups as being rated as good (Group I), fair (Group II), and poor (Group III), as possible sites for photovoltaic PST.

2.6 Selection of Potential Sites in Each Geographical Region

Three potential sites were selected for each geographical division. These sites were selected on the following basis:

(1) Representation of the range of conditions (insolation, weather, population, etc) existing in the division.

(2) Good potential of available government, non-DOD land.

It is not within the scope of this preliminary study to rate each site individually, as with the geographical division. Instead, each division was inspected for its range of conditions. Sites were then selected to best represent the range. In addition, each site was considered for the availability of non-DOD government land. Each site should be considered as an area rather than an exact site; for example, "Miami" indicate the Miami area rather than the city of Miami. The results of the site selection are listed below and an overview of the site locations are shown in Figure 2-5.

Geographical Division - New England (NE)

Sites: NE-1, State Capitol at Augusta, Maine

NE-2, Concord, New Hampshire

NE-3, Department of Transportation, Havard University, or Massachusetts Institute of Technology, Draper Lab, Smithsoian AOB, at Cambridge, Massachusetts.

Geographical Division - Middle Atlantic (MA)

Sites: MA-1, ERDA (River Road or West Miltow) at Schenectady, New York

MA-2, ERDA Bureau of Mines or ERDA (Pleasant Hills), University of Pittsburgh, at Pittsburgh, Pennsylvania

MA-3, ERDA New Brunswick Laboratory at New Brunswick, New Jersey

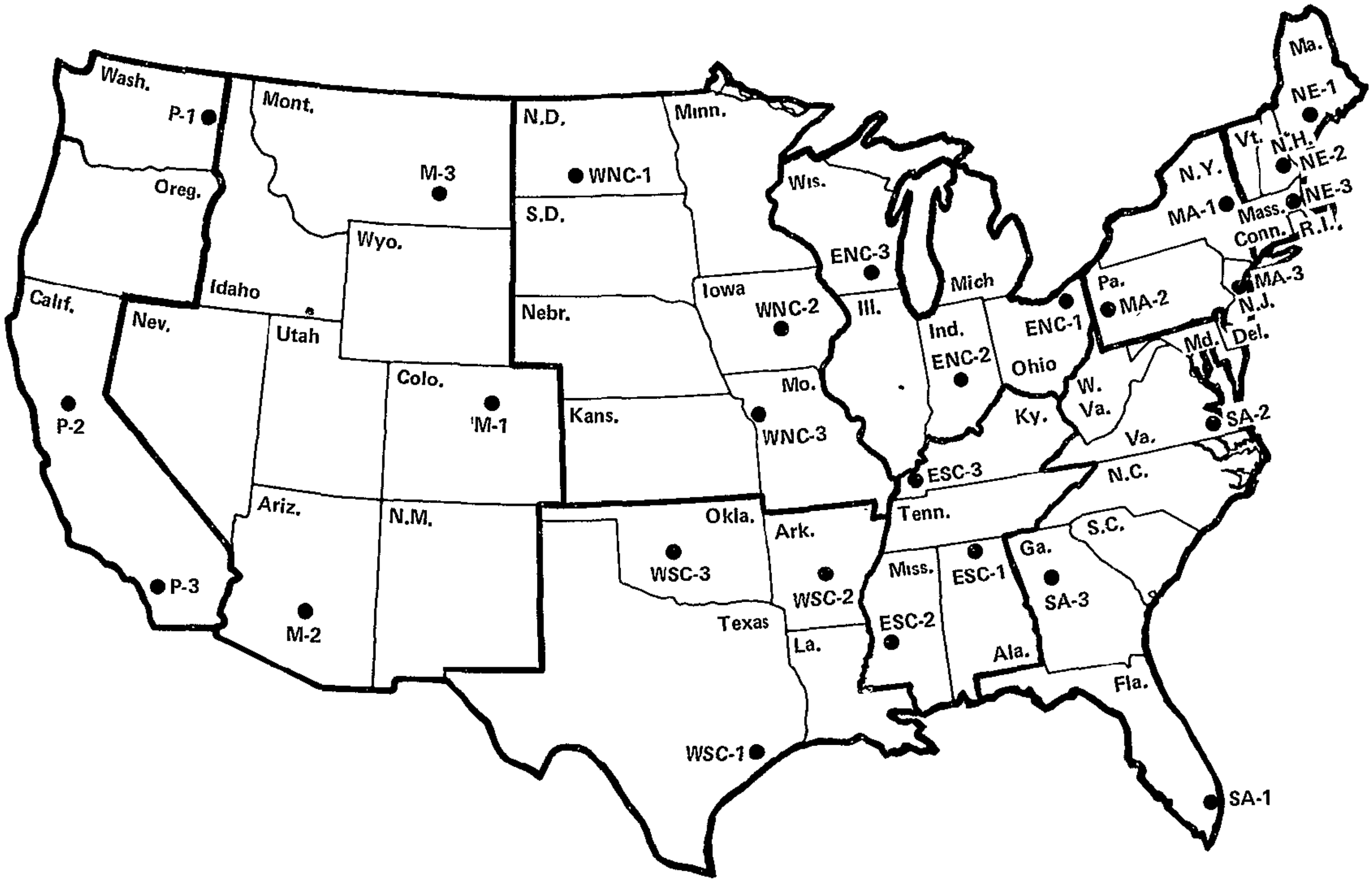


Figure 2-5 Potential PST Sites in Each Region

Geographical Division - East North Central (ENC)

Sites: ENC-1, NASA Lewis Research Center at Cleveland, Ohio

ENC-2, State Capital at Indianapolis, Indiana

ENC-3, State Capital or University of Wisconsin Forest Products Laboratory at Madison, Wisconsin

Geographical Division - South Atlantic (SA)

Sites: SA-1, University of Miami at Miami, Florida

SA-2, NASA Langley Research Center at Hampton, Virginia

SA-3, U.S. Postal Service, FAA-ARTCC, Federal Reserve Board at Atlanta, Georgia

Geographical Division - East South Central (ESC)

Sites: ESC-1, NASA (MSFC) at Huntsville, Alabama

ESC-2, V.A. Center at Jackson, Mississippi

ESC-3, ERDA at Puducah, Kentucky

Geographical Division - West South Central (WSC)

Sites: WSC-1, NASA Manned Spacecraft Center at Houston, Texas

WSC-2, Little Rock, Arkansas

WSC-3, FAA, Oklahoma City, Oklahoma

Geographical Division - Mountain (M)

Sites: M-1, Federal Center at Denver, Colorado

M-2, State Capital at Phoenix, Arizona

M-3, Billings, Montana

Geographical Division - Pacific (P)

Sites: P-1, Bureau of Mines at Spokane, Washington

P-2, State Capital, Sacramento, California

P-3, NASA Jet Propulsion Laboratory or USDA Forest Service in Pasadena, California

Geographical Division - West North Central (WNC)

Sites: WNC-1, Bismark, North Dakota

WNC-2, State Offices at Des Moines, Iowa

WNC-3, ERDA at Kansas City, Missouri

The sources used in identifying federal land and potential sites were the *National Atlas* and the *Federal Telecommunications System Users Guide*. For some sites, federal land (non-DOD) could not be readily located. Therefore, state land was considered as a possible alternative. With this approach, 86% of the sites can be located on federal and/or state land. Thus, it was obvious from this study that a problem may exist concerning the location of all sites on non-DOD federal property. A more detailed search at the local site is called for to resolve this problem. This is especially true, when considering the detailed nature of the sites in terms of the basic objectives of the PST. Such factors as the existence of obstructions (to the sun), amount of suitable land actually available, etc. must be studied in more detail for each potential site.

Additional information was obtained on three potential sites in the Denver, Colorado; Pasadena, California; and Phoenix, Arizona areas. This is summarized below:

Site No. 1 - Denver, Colorado - Federal Center

This site is located within the Mountain geographical division. This division received the highest numerical rating of the nine geographical divisions. In general, the site has excellent solar insolation conditions - annual percentage of sunshine of 70%, good climate, a high population growth rate, and excellent public visibility.

The PST could be located on non-DOD federal lands at the Denver Federal Center complex located at W. 6th Ave. and Kipling Streets. This complex covers several acres of land and houses several governmental agencies e.g., Bureau of Reclamation and the United States Geologic Survey). The complex is located in the west metropolitan Denver area (city of Lakewood), near major freeways (Interstate I-70), and has very good public exposure. It is well protected with a perimeter fence and guarded entrances, but still has good public access. The complex has several open areas where a PST could be located without objects shading it from the sun.

Site No. 2 - Pasadena, California - Jet Propulsion Laboratory (JPL)

This site is located within the Pacific geographical division which ranked second in the ratings for the nine geographic divisions. In general, the site has good exposure to sunlight and public visibility. In addition, JPL has a demonstrated interest in solar energy.

The PST could possibly be located in available parking lots that are on a southern slope and are unobstructed. JPL maintains security to protect against vandalism and they also have public information exchange programs.

This site offers an opportunity to study the impact of air pollution on the PST. In addition to having a high percentage of high intensity sunlight, this site is occasionally impacted by air pollution haze that noticeably reduces the sunlight level. This will allow a comparison to be made between ideal conditions and polluted conditions.

Site No. 3 - Phoenix or Tucson, Arizona - University of Arizona or Arizona State University

Both sites are located in the desert southwest of the Mountain division. Each site represents the extreme in amount and level of sunshine. They have excellent public visibility since both have had highly publicized programs and interests in solar energy.

The site could be located on university property having unobstructed sunlight, public exposure, and security against vandalism.

3.0 TASK II - PARAMETRIC SENSITIVITY ANALYSIS

3.1 Introduction and Summary

The objectives of the parametric sensitivity analysis were to: (1) delineate the range of parameters and design options of interest relative to residential photovoltaic systems and (2) identify parameters that are critical to optimization and require systems experiments and operational experience for proper evaluation.

A survey was conducted of existing photovoltaic system configurations applicable to residential prototype systems. This resulted in the selection of four Electrical Power System (EPS) candidate configurations for parametric analysis purposes. A computer program was developed to aid the evaluation of these configurations and to identify sensitive parameters. This program consisted of the solar irradiance model, solar array model, electrical load model, and energy balance model. An analysis was conducted to identify the critical parameters and a range of operational values for each parameter in the models. These values were then used in the computer program to evaluate system and component performance characteristics: (1) Cleveland, Ohio; (2) Gainesville, Florida; (3) Blue Hill, Massachusetts; (4) Denver, Colorado; and (5) Phoenix, Arizona.

The significant results of the parametric-sensitivity analysis are as follows:

(1) The EPS configuration containing only the basic components (viz., solar array, battery, battery charger, inverter, and the associated switching and controls circuitry) is desirable for experimental purposes. It is therefore recommended for the PST. However, the sensitivity data clearly indicate the technical and cost advantages of not using the battery purely for energy storage purposes. Therefore for actual residential application as compared to the PST, and EPS configuration without the battery (i.e., without the capability to store the solar array energy) is recommended.

(2) The principal advantages of eliminating the battery are:

   (a) Higher annual energy displacement can be obtained (i.e., it requires lower utility energy);

(b) The initial cost and continual maintenance of the battery is eliminated;

(c) For a given bus power requirement, the solar array area can be reduced significantly.

The disadvantages of the no-battery configuration are that:

(a) The local utility firm must be willing to accept power fed back from the consumer;

(b) Technical problems associated with the parallel operation of the utility and the PST inverter are not fully understood;

(c) A significant development effort is required to provide an inverter that has the capability to operate the solar array at its peak power point.

(3) The principal advantage of the EPS configuration with the battery is that it permits the system to operate independently of the utility grid under certain conditions. However, it appears that any practical PST or final residential photovoltaic EPS will require utility power (e.g., during cloudy days or intermittent sunlight conditions, for periods of peak power demand, etc.). Further studies are needed to determine the practicality and real benefits of autonomous photovoltaic/battery residences.

(4) The solar insolation analysis indicate that both clearness number and percent sunshine are the major determinants of daily integrated and total yearly solar irradiance.

(5) The most sensitive parameters affecting the overall EPS performance are the solar intensity profile, electrical load demand, inverter efficiency, and the presence or the absence of the battery. With the presently available inverters, the use of multiple inverters of various ratings is necessary to achieve a high system performance and efficiency over a widely varying electrical load demand. The solar intensity characteristics and the electrical load demand primarily affect the sizing of the EPS at a given PST site.

3.2 Description of EPS Configurations with Battery

Configuration I. Configuration I (see Fig. 3-1) features a dc battery charger/peak power tracker combination. The peak power tracker contained in the dc battery charger would provide for a solar array utilization factor equal to or greater than 90%. The utilization factor represents the percentage of solar array energy that is extracted from the total solar array energy available. Maximum energy is obtained from the solar array when operation is maintained at the peak power point. This point occurs at the knee of the solar array characteristic IV curve. The peak power tracker allows the solar array to operate near the peak power point when the battery is capable of accepting the full charge current.

The auxiliary load shown is a noncritical load that is functional over a widely varying dc input. Such a load might be a heating element for a water container or a heater coil. The primary purpose for the auxiliary load is to utilize excess energy from the array that is not consumed by the load or the system battery. In this respect the auxiliary load serves as a passive peak power tracker after the battery is fully charged. The auxiliary load serves primarily the same function in all of the proposed EPS configurations.

The ac battery charger provides for charging of the battery bank from the utility at night or at any time when the power from the solar array is inadequate for battery charging. The ac charger is not necessarily a required component for a generalized EPS. It will facilitate testing, however because the battery can be charged independent of weather conditions.

The utility interface provides the switching mechanism (contactors or solid state switches) to isolate the utility grid from the PST power system when the inverter is functioning or to allow parallel operation of the inverter output with the utility grid. The utility service box is the housing for the main circuit breakers and is a standard component of the utility service entrance.

The solar array distribution unit contains the blocking diodes that protect each series string of subarrays from reverse current.

Configuration II. Generally the components of Configuration II (see fig. 3-2) perform the same functions as those described for Configuration I. Note that the solar array, solar array

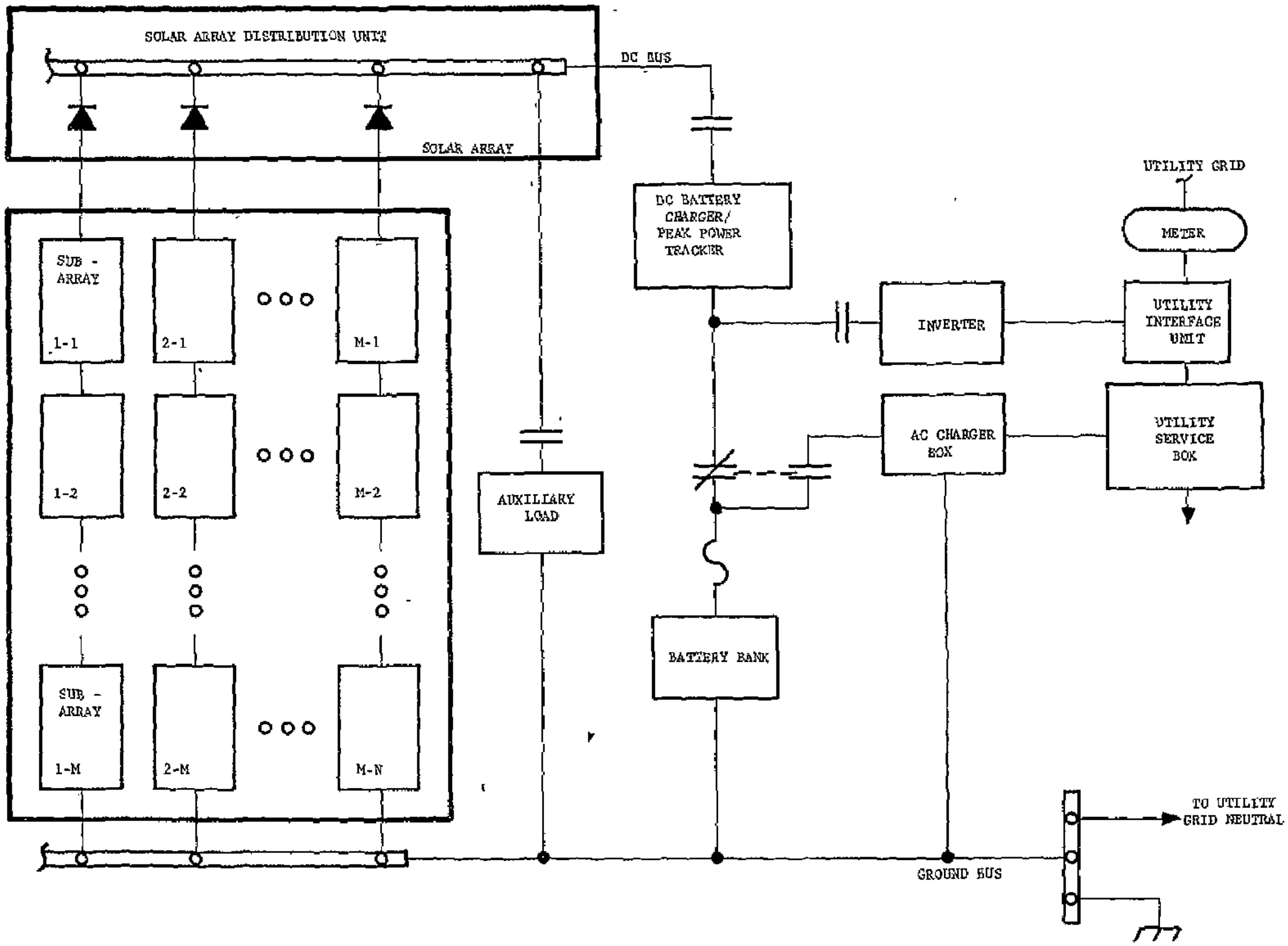


Figure 3-1 Configuration I EPS Block Diagram

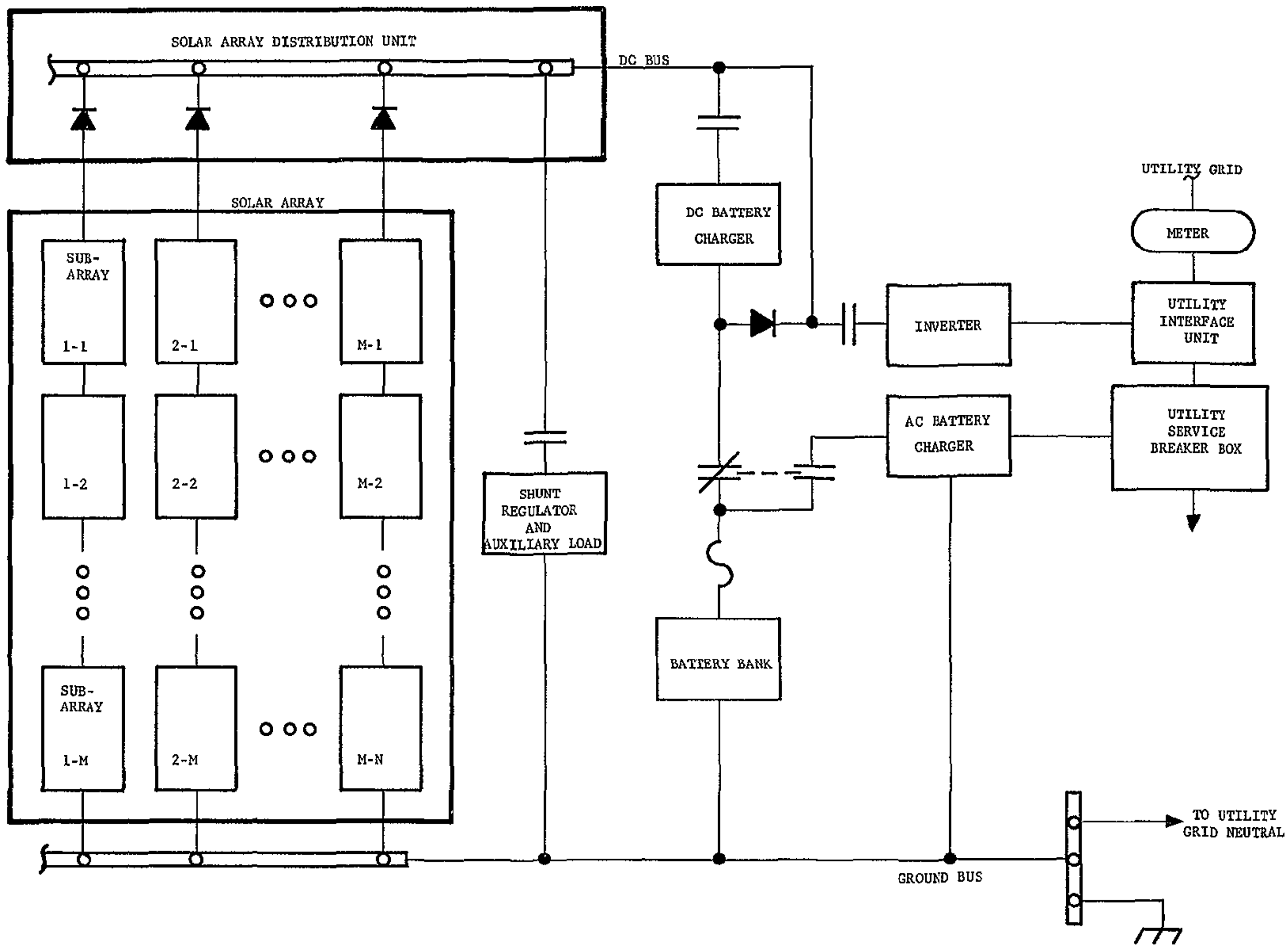


Figure 3-2 Configuration II EPS Block Diagram

distribution unit, ac charger, and the utility interface components are identical for Configurations I, II, and III. The significant difference between I and II is that the battery charger in II is not in series with the entire power flow of the PST and therefore, supplies power to the battery only. As a result, daytime power can pass directly from the solar array distribution unit to the inverter without encountering the efficiency loss of the dc charger. The dc charger is an integral component of both Configurations I and II owing to the battery charge voltage specification (for lead acid battery, 2.4 volts/cell is the maximum allowable charge voltage). The uncontrolled solar array voltage varies widely depending on the solar array temperature and the insolation level. If the battery is connected directly across the solar array output without a charge controller, the battery may be subjected to an excessive overcharge condition. This overcharge condition generates excessive gas and heat within the battery resulting in reduced battery life. The dc charger maintains the battery charge voltage and current at desired operating conditions. It also charges at a much reduced current rate (trickle charges) to offset small losses after the battery attains full charge.

Because of the change in the charger position (in Configuration II), an additional diode is required to connect the battery to the dc bus. This supplementary control element will reduce the total power system efficiency.

Configuration III. Configuration III (fig. 3-3) requires no dc battery charger. This eliminates the dc charger efficiency loss. However, the method of peak power tracking used (auxiliary load) lacks the sophistication of the tracker operated in Configuration I. As a result, the increase in total system efficiency gained by deletion of the dc charger is partially offset due to a reduced solar array utilization factor. In the absence of the dc charger, a shunt regulator is provided to insure a dc bus voltage compatible with battery charge voltage limits. The shunt regulator operates only during periods when the solar array voltage exceeds the system voltage limits (determined by battery and inverter input requirements). When the shunt regulator is not operating, the system voltage is controlled by the battery terminal voltage.

Configuration IV. A fourth configuration (see fig. 3-4) was originally proposed as a viable power system candidate. However, subsequent analysis of this system has shown it to be the least efficient because of the additional power conditioning component, i.e., the boost regulator. Because the boost regulator is not an off-the-shelf item, development cost would also be incurred. The

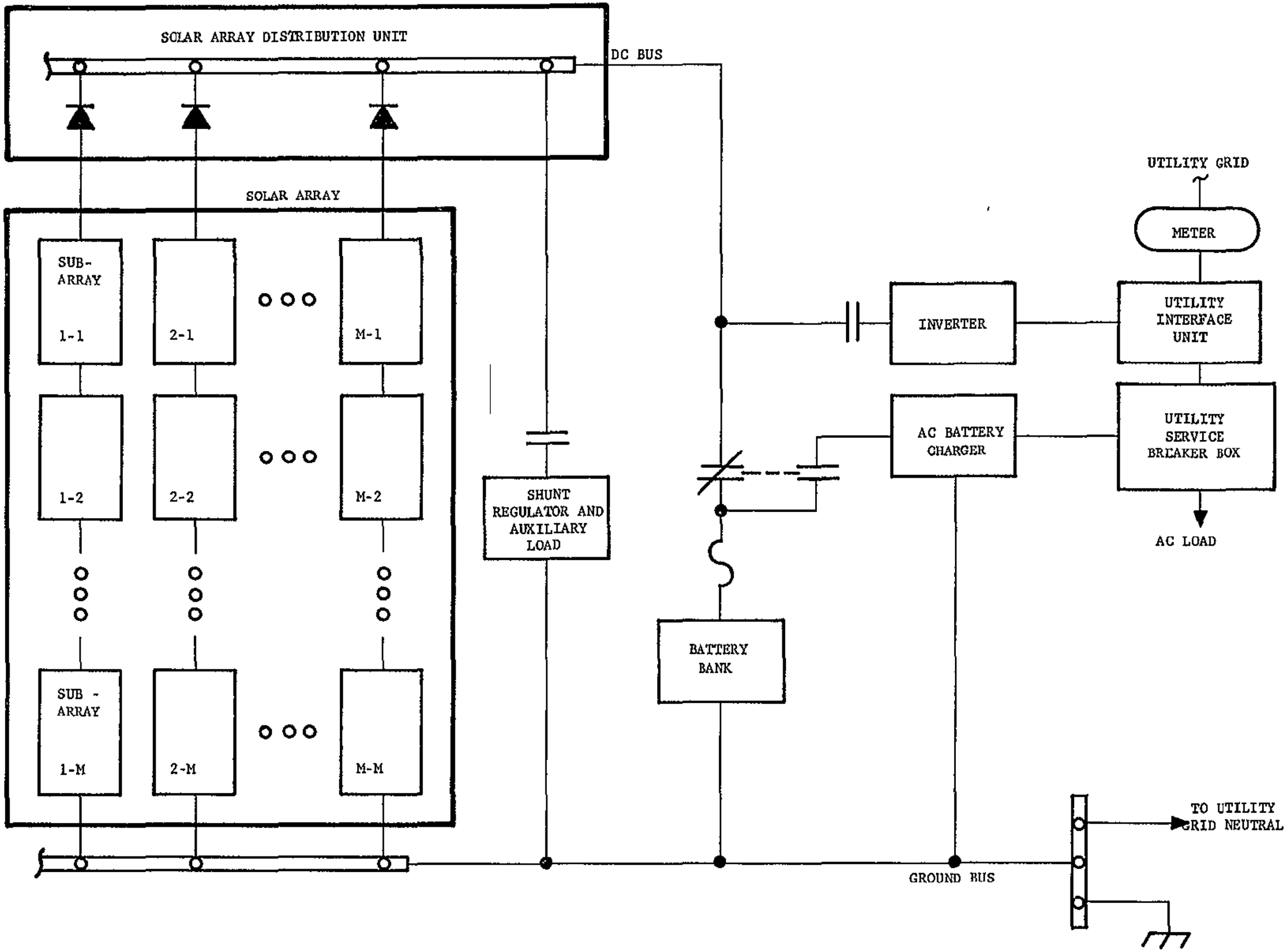


Figure 3-3 Configuration III EPS Block Diagram

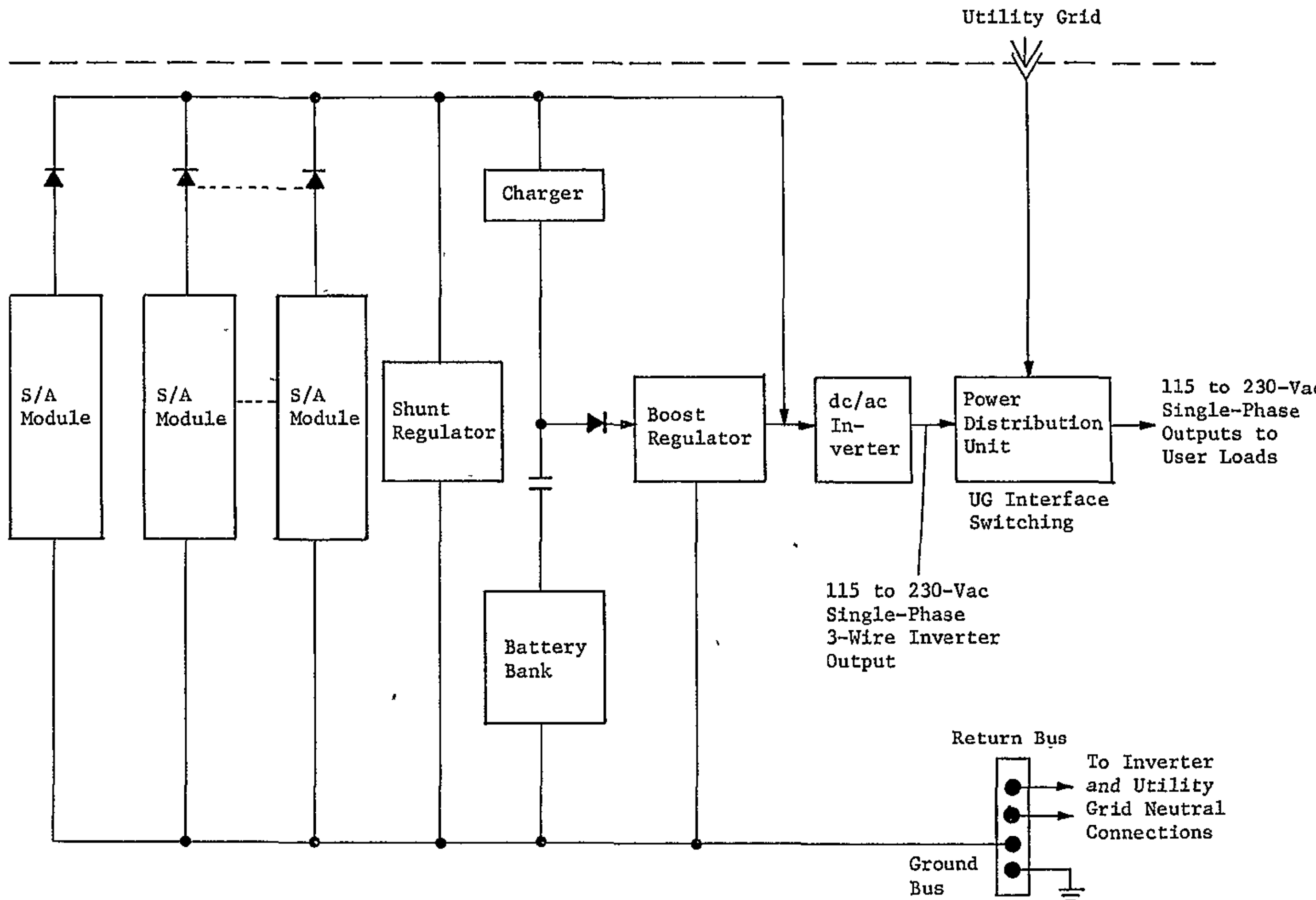


Figure 3-4 Configuration IV EPS Block Diagram

main reason for considering a boost regulator system is to reduce the number of series cells in a battery. The solar array would provide output voltage nominally above the minimum inverter input voltage requirement.

Because of higher cost and lower overall system efficiency than Configuration III, Configuration IV was discarded as a practical PST candidate and was not included in the parametric analysis.

3.3 Description of EPS Configurations without Battery

Each of the three basic EPS configurations (see figs. 3-1, 3-2, and 3-3) can be used effectively without the battery. When the battery is removed, other components of the EPS can be eliminated as well. When a component is deleted, the power loss of that component in a given configuration is eliminated. The specific modifications applied to each general configuration are as follows:

Configuration I. Remove the battery and ac charger. The dc charger remains to provide peak power tracking and voltage regulation for the inverter.

Configuration II. Remove the battery, the ac charger, and the dc charger. The output voltage is maintained primarily by the auxiliary load (functioning as a shunt regulator.)

Configuration III. Remove the battery and ac charger. The shunt regulator remains to control the peak solar array output voltage. Therefore, both the shunt regulator and auxiliary load can be removed. If the inverter capability is less than the solar array capability, the shunt regulator and auxiliary load must remain to prevent the array voltage from exceeding the inverter upper voltage limit.

Computer Program Model

The program is comprised of four major models as illustrated in Figure 3-5. These are the solar irradiance, solar array, electrical load, and energy balance models. The solar irradiance model predicts the insolation level on a given surface for any location in the northern hemisphere at any time of the year. The solar array model determines the output of a solar array using the output from the solar irradiance model. The electrical load model converts load profile inputs into average daytime and average nighttime power levels and calculates the total daily (24 hr) energy required by the load. The energy balance model uses inputs from the electrical load and solar array models. It accounts for all power

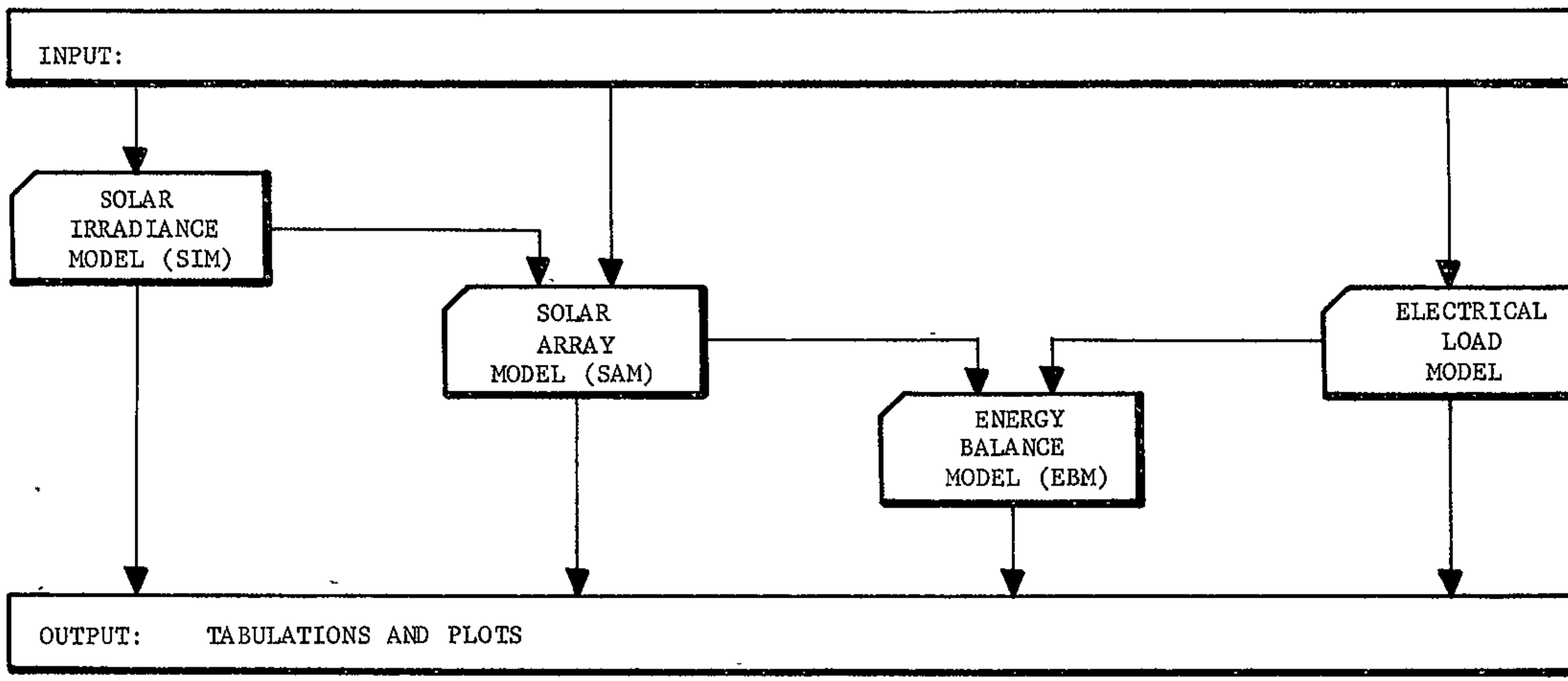


Figure 3-5 PST Computer Program Block Diagram

system losses, and day and night duration, and predicts the EPS capability based on energy balance relationships. Energy balance occurs when the daily solar array energy minus the system losses equals the energy required by the load for a one day (24 hr) period. Appendix A provides a detailed description of each computer model.

3.5 Selection and Range of Variables for Sensitivity Analysis

3.5.1 Solar Irradiance Model (SIM). The SIM input variables are listed as follows:

(1) Site latitude, L;

(2) Site longitude, ℓ ;

(3) Panel tilt angle, PT;

(4) Panel azimuth angle, PA;

(5) Day definition matrix:

Percent sunshine, PS;
Total cloud amount, TCA;
Number of day segments, NOFRC;

(6) Clearness number, CN;

(7) Ground reflectance, ρ_g;

(8) Time zone number, TZN; and

(9) Local time, LT; 0 - Standard Time; 1 - Daylight Savings Time.

The nominal ranges of these input variables for the United States are given in Table 3-1.

Table 3-1

Range of SIM Input Variables

Input	Nominal Range
L	25 to 50 deg N
ℓ	65 to 125 deg W
PT	0 to 90 deg
PA	± 90 deg
PS	25 to 95%
TCA	0 to 10
CN	0.70 to 0.95
ρ_g	0.10 to 0.80
TZN	5 to 8
NOFRC	1 → 10
LT	0, 1

The major variables selected for the SIM sensitivity analysis were as follows:

(1) clearness number, CN,

(2) total cloud amount, TCA;

(3) panel tilt angle, PT;

(4) panel azimuth angle, PA;

(5) percent sunshine, PS;

(6) ground reflectivity, ρ_g;

(7) day definition matrix;

(a) simple "fixed" partly cloudy day definition, nominal conditions;

(b) "even" distribution partly cloudy day definition, nominal conditions;

(c) 100% clear day definition;

(d) continuous partly cloudy, TCA applied all day, day definition;

(e) "worst" case, simple "fixed", day definition, partly cloudy day, nominal conditions; and

(f) "worst" case, "even", day definition, partly cloudy day.

The geographical site used for the SIM sensitivity analysis was Denver, Colorado. Denver is located at midlatitude and measured clearness numbers were available for the analysis.

As discussed previously, five sites, including Denver, were used for the Solar Array Model (SAM) sensitivity analysis. For these analyses, an "even" distribution, partly cloudy, day definition matrix was used for all sites. The major SIM variables were selected from the best available data. For example, the clearness numbers (for each site) were selected from Figure 3-6. The percent sunshine per month was selected from the *National Climatic Atlas*. The total cloud amount was set equal to zero or ten for conditions ranging from clear to totally overcast, respectively. In general the panel tilt angle was set equal to the site latitutde, and the panel azimuth angle was set equal to zero (due south). The ground reflectivity was set at a nominal value of 0.2. A complete listing of the SIM variables used for the five sites is given in the Table 3-2. Because the percent sunshine varies monthly for each site, monthly day definitions were formulated according to methods described for each site. The values used for the SIM sensitivity analysis are shown in Tables 3-3 through 3-10.

The SIM sensitivity analysis was performed for a series of cases. For each case, all major variables were fixed except the variable being analyzed for sensitivity. For example, the clearness number case would be performed by setting TCA, ρ_g, PT, and PA equal to a constant value while the clearness number was varied from 0.85 to 1.05. In some cases, the type of day definition was also varied. For example, for the clearness number case, two sets of day definitions were chosen - 100% clear and "nominal even". We did this to determine the impact of the day definition on the sensitivity analysis. For each case, the sensitivity of the parameter was measured by the monthly and yearly integrated solar irradiance. Tables 3-3 through 3-10 define the cases and variables for the SIM sensitivity analysis.

As shown in Table 3-3, the clearness number was varied from 0.85 to 1.05, while the values for TCA were fixed at 0 for the 100% clear day definition or 0 and 10 for the nominal "even" day. The value of the ground reflectance, g, was fixed at 0.2. The panel tilt angle (PT) was fixed at 0 deg (horizontal surface) and the panel azimuth angle was fixed at 0 deg. The 100% clear day definition is characterized by zero cloudiness and is representative of maximum solar irradiance. The nominal "even" day definition was formulated from the

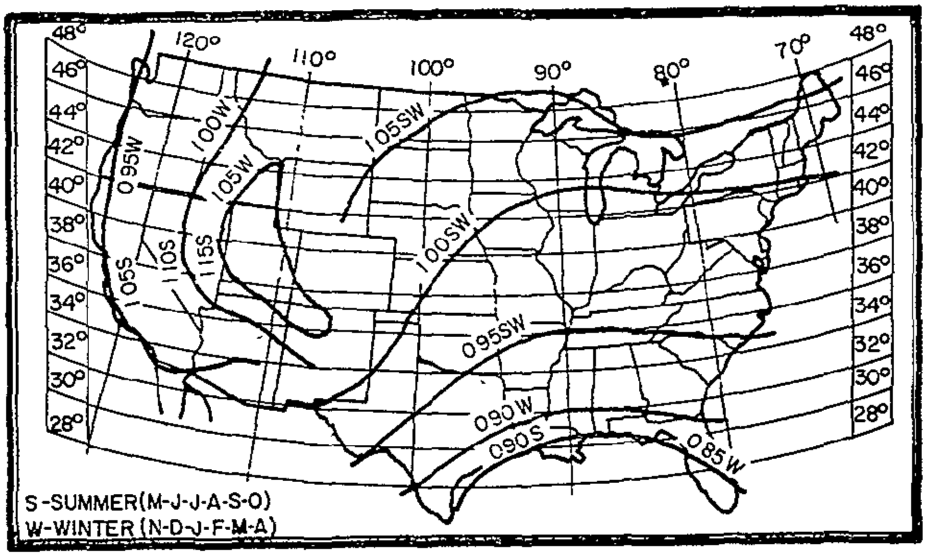


Figure 3-6 Clearness Numbers for United States

Table 3-2 Major SIM Variables for SAM Analysis

Variables, Month	Denver		Cleveland		Blue Hill		Gainsville		Phoenix	
	CN	PS	CN	PS	CN	PS	CN	PS	CN	PS
Jan	0.95	67	0.90	29	0.90	47	0.81	58	0.95	76
Feb		67		36		56		59		79
Mar		65		45		57		66		83
April		63		52		56		71		88
May		61		61		59		71		93
June		69		67		62		63		94
July		68		71		64		62		84
Aug		68		68		63		63		84
Sept		71		62		61		58		89
Oct		71		54		58		58		88
Nov		67		32		48		61		84
Dec	0.95	65	0.90	25	0.90	48	0.81	53	0.95	77
Latitude	39.73°N		41.50°N		42.22°N		29.66°N		33.40°N	
Longitude	104.98°W		81.70°W		72.12°W		82.33°W		112.00°W	
Ground Reflectance	0.20		0.20		0.20		0.20		0.20	
Panel Tilt Angle	39.73°n		41.50°n		42.22°n		29.66°n		33.40°n	
Panel Azimuth Angle	0°		0°		0°		0°		0°	

Table 3-3 Case I Clearness Number Sensitivity Analysis Parameters

CN	TCA	ρ_g	PT, deg	PA, deg	Day Definition
0.85	0	0.2	0	0	100% Clear
0.95	0	0.2	0	0	
1.00	0	0.2	0	0	
1.05	0	0.2	0	0	
0.85	0, 10	0.2	0	0	Nominal "Even"
0.95	0, 10	0.2	0	0	
1.00	0, 10	0.2	0	0	
1.05	0, 10	0.2	0	0	

Table 3-4 Case II - Total Cloud Amount Sensitivity Analysis Parameters

TCA	CN	ρ_g	PT	PA, deg	Day Definition
2	0.95	0.2	39.73	0	Continuous Partly Cloudy
4	0.95	0.2	39.73	0	
6	0.95	0.2	39.73	0	
8	0.95	0.2	39.73	0	
2	0.95	0.2	39.73	0	"worst" case "even" distribution
4	0.95	0.2	39.73	0	
6	0.95	0.2	39.73	0	
8	0.95	0.2	39.73	0	

Table 3-5 Case III - Panel Tilt Angle Sensitivity Analysis Parameters

PT, deg	CN	ρ_g	PA, deg	TCA	Day Definition
0	0.95	0.2	0	0, 10	Nominal "even"
39.73	0.95	0.2	0	0, 10	
90	0.95	0.2	0	0, 10	

Table 3-6 Case IV - Panel Azimuth Angle Sensitivity Analysis Parameters

PA, deg	CN	TCA	ρ_g	PT	Day Definition
+45°	0.95	0, 10	0.2	39.73	nominal "fixed"
-45°	0.95	0, 10	0.2	38.73	

Table 3-7 Case V - Percent Sunshine Sensitivity Analysis Parameters

PS	CN	TCA	ρ_g	PT	PA, deg	Day Definition
20	0.95	0, 10	0.2	39.73	0	Nominal "Even"
40	0.95	0, 10	0.2	39.73	0	
60	0.95	0, 10	0.2	39.73	0	
80	0.95	0, 10	0.2	39.73	0	
20	0.95	0, 10	0.2	39.73	0	Nominal "Fixed"
40	0.95	0, 10	0.2	39.73	0	
60	0.95	0, 10	0.2	39.73	0	
80	0.95	0, 10	0.2	39.73	0	

Table 3-8 Case VI - Ground Reflectance Sensitivity Analysis Parameters

ρ_g	CN	TCA	PT, deg	PA, deg	Day Definition
0.2	0.95	0, 10	39.73	0	Nominal "Even"
0.4	0.95	0, 10	39.73	0	
0.6	0.95	0, 10	39.73	0	
0.8	0.95	0, 10	39.73	0	
0.2	0.95	0, 10	90	0	
0.4	0.95	0, 10	90	0	
0.6	0.95	0, 10	90	0	
0.8	0.95	0, 10	90	0	

Table 3-9 Case VII - Day Definition Sensitivity Analysis Parameters

Day Definition	CN	TCA	PT, deg	PA, deg	ρ_g
Nominal "fixed"	0.95	0, 10	0	0	0.2
Nominal "even"	0.95	0, 10	0	0	0.2
"Worst even"	0.95	0, 10	0	0	0.2
"Worst fixed"	0.95	0, 10	0	0	0.2
100% clear	0.95	0, 10	0	0	0.2

Table 3-10 Case VIII - Sensitivity of Total Yearly Solar Irradiance to Panel Tilt Angle and Yearly Distribution of Percent Sunshine

Site	CN	ρ_g	PA	PT
Denver	0.95	0.2	0	Latitude (lat) +25
				Lat +20
				Lat +15
				Lat +10
				Lat +5
				Lat
				Lat -5
				Lat -10
	0.95	0.2	0	Lat -15
Cleveland	0.90	0.2	0	Lat -20

percent sunshine data shown in Table 3-2. This percent sunshine (on a monthly basis), was then distributed evenly throughout the day. This was done by calculating five day parts on a clear (TCA = 0) basis and five day parts calculated on a cloudy (TCA = 10) basis. An example is shown in Table 3-11.

Table 3.6.2-11 Nominal "Even" Day Definition for Denver, Colorado, January, Percent Sunshine = 67%

Day Part	1	2	3	4	5	6	7	8	9	10
Day Fraction	0.134	0.066	0.134	0.066	0.134	0.066	0.134	0.066	0.134	0.066
TCA	0	10	0	10	0	10	0	10	0	10
Clear	X		X		X		X		X	
Cloudy		X		X		X		X		X

Table 3-4 shows the parameters for determining the TCA sensitivity. The clearness number was fixed at 0.95 and the ground reflectance was fixed at 0.2. The panel tilt angle was fixed at 39.73 deg (Denver latitude) and the panel azimuth angle was fixed at 0 deg (due south). Two types of day definitions were addressed: (1) a continuous partly cloudy day, and (2) a "worst" case "even" distribution day. The continuously partly cloudy day is characterized by neither clear nor cloudy portions, rather the entire day is assigned a constant TCA (from 2 to 6) as shown in table 3-12.

Table 3-11 Continuous Partly Cloudy Day Definition for Denver, Colorado (TCA = 2)

Day Part	1
Day Fraction	1
TCA	2

The "worst" case "even" day definition is characterized similarly to a nominal "even" day, except during those portions of the day that are totally clear (TCA = 0) in the nominal day. The worst case day is assigned a TCA (from 2 to 8) which results in a reduction of the direct solar irradiance. An example of a worst case even day is shown in Table 3-13.

Table 3.6.2-13 Worst Case Even Day Definition for Denver, Colorado, January, TCA = 2

Day Part	1	2	3	4	5	6	7	8	9	10
Day Fraction	0.134	0.066	0.134	0.066	0.134	0.066	0.134	0.066	0.134	0.066
TCA	2	10	2	10	2	10	2	10	2	10

The panel tilt angle sensitivity was determined by fixing the clearness number at 0.95 and the ground reflectance was fixed at 0.2. The panel azimuth angle was set at 0 deg (see table 3.5). The day definition used was the nominal "even" case (see table 3-11). The panel tilt angles considered were 0 deg (horizontal panel), 39.73 deg (site latitude), and 90 deg (vertical panel). This was done mainly to show the general relationship of solar irradiance to panel tilt angle.

The sensitivity of the panel azimuth angle was studied by fixing the clearness number at 0.95 and the ground reflectivity at 0.2. The panel tilt angle was set at 39.73 deg. Previous GE studies have shown that the total integrated yearly solar irradiance is not significantly changed for panels having azimuth angles of 0° ± 20°. This holds true if approximately the same amount of solar irradiance is received in the morning and afternoon hours. This situation occurs on clear days and nominal "even" days. However, if a given site has cloudiness occurring either predominantly in the morning or afternoon, the amount of solar irradiance (daily) received will be sensitive to panel azimuth angle. If a site has predominant afternoon cloudiness, a panel oriented east will collect more solar irradiance than a panel oriented west. To show such a sensitivity, two panel azimuth angles were considered - +45 deg (west) and -45 deg (east). The day definition used was a nominal "fixed" type. This type is characterized by a fixed time during the day that cloudiness occurs. The percent sunshine values for Denver were used and the cloudiness portion of the day was fixed in the afternoon hours. For example, see the day definition matrix shown in Table 3-14.

Table 3-14 Nominal "Fixed" Day Definition for Denver, Colorado, January, Percent Sunshine = 67%

Day Part	1	2
Day Fraction	0.67	0.33
TCA	0	10
Clear	X	
Cloudy		X

The percent sunshine sensitivity was determined by varying the percent sunshine from 20 to 80 and fixing the clearness number at 0.95. The ground reflectivity was fixed at 0.2, the panel tilt angle at 39.73 deg, and the panel azimuth angle was fixed at 0 deg. Two types of day definitions were addressed: the nominal "even" and the nominal "fixed" cases, as previously defined.

As shown in Table 3-8, the ground reflectivity sensitivity was addressed by fixing the clearness number at 0.95 and the panel azimuth angle at 0 deg. Two panel tilt angles were studied: 39.73 deg (latitude of site) and 90 deg (vertical panel). The 39.73 deg panel tilt angle represents a nominal case of ground reflectivity sensitivity while the 90 deg tilt angle represents the most sensitive case. The day definition used was the nominal "even" case.

The day definition sensitivity (table 3-9) was determined by fixing the clearness number at 0.95, the panel tilt angle at 0 deg, the panel azimuth angle at 0 deg, and the ground reflectivity at 0.2. The day definitions considered were the nominal "fixed" case (table 3-14), the nominal "even" case (table 3-11), the "worst" case "even" (table 3-13), the 100% clear case, and the "worst" case "fixed" case. The "worst" case "fixed" case is defined similarly to a nominal fixed case except the clear portions of the day are replaced with TCAs taken from the *National Climatic Atlas* (see table 3-15).

Table 3-15 "Worst" Case "Fixed" Day Definition for Denver, Colorado, January, Percent Sunshine = 67%, Total Cloud Amount = 4.5

Day Part	1	2
Day Fraction	0.67	0.33
TCA	4.5	10

The sensitivity of total yearly solar irradiance to panel tilt angle and the yearly distribution of sunshine was determined by considering the Denver and Cleveland sites and varying the panel tilt angle between latitude +25 and latitude -25 deg. The Denver site is characterized by a uniform yearly distribution of sunshine while the Cleveland site is characterized by a nonuniform distribution of sunshine (see table 3-2). The appropriate clearness numbers were used for each site, the ground reflectivity was fixed at 0.2, the panel azimuth was fixed at 0.0 deg (due south), and the day definition was set to an "even" distribution of cloudiness.

In addition to the sensitivity analyses of each major input variable, an analysis was made to check the comparison of SIM data for each of the five sites with available *National Climatic Atlas* data for the monthly horizontal solar irradiance. These *National Climatic Atlas* data are based on all usable solar radiation data (direct and diffuse) measured on a horizontal surface and published in the *Monthly Weather Review* and *Climatological Data National Summary* through 1962. The data consists of the monthly mean daily solar radiation on a horizontal surface. The corresponding SIM analyses were performed using clearness numbers for each site (given previously), percent sunshine data for each site (given previously), and a panel tilt angle of 0 deg. The day definition used was the nominal "even" distribution of cloudiness. As discussed previously, this type of distribution will very likely be the most realistic and statistically accurate.

3.5.2 Solar Array Model (SAM) - The range of values for the input parameters are shown in Table 3-16. The effects of value changes for each parameter were analyzed to determine the sensitivity of the EPS performance to a specific parameter. The parametric sensitivity was obtained by allowing one parameter to vary while maintaining all others constant at the nominal values shown in Table 3-16. Parameters identified as critical during the initial analysis were singled out for computer evaluation. For example, EPS performance is quite sensitive to the subarray power output P_{SAM60} . To generate the parametric data, several computer runs were used, each with a different value of P_{SAM60}. This technique permitted ease in comparing the total system output for a change in a single parameter.

3.5.3 Energy Balance Model (EBM) - The range of input parameter variation for the energy balance model is shown in Table 3-17. The method used for the sensitivity analysis is identical to that used for the solar array model. The values used in the table are averages for the component range of operation. For example, the actual inverter efficiency is a function of the load.

3.5.4 Electrical Load Model (ELM) - The input for the ELM depends on the chosen load profile. Both constant annual loads and representative.

load profiles for a given site were used to determine the EPS performance as a function of load. A typical load profile used for Cleveland, (based on the 1962 Aerospace Corporation tape is shown in Figure 3-7).

Table 3-16 Range of Input Parameters for Solar Array Model

Item	Description	Range: Symbol	Range: Minimum	Range: Nominal	Range: Maximum	Units
1.	Number of 3x3 subarrays 1.219m x 1.219m (4 ft x 4 ft)	M	80	90	105	Subarrays
2.	Temperature of Each Zone	t_{ij}	30	40	50	°C
3.	Percentage of Total Solar Array Occupied by Temperature Zone	Apz_i	--*	--*	--*	%
4.	Number of Temperature Zones	Z				Zones
5.	Power Temperature Coefficient	α	-0.268†	-0.329	-0.389	Watts/°C
6.	Subarray Power Output at 60 deg and H_{STD}	P_{SAM60}	70	85	100	Watts
7.	Solar Array Degradation Factor	F_D	0§	0.2	0.5	%/Month

*If only one temperature for the array is used, Apz_i will automatically be 100%. If more than one zone is employed, the total array area can be divided between the zones in any proportion as long as the total area of all zones equals 100%.

†-0.268 relates to 70W, -0.389 relates to 100W, etc (derivation shown in Appendix B).

§Degradation Factor Equation, $P_{S60_t} = P_{SAM60}\left(\frac{100 - F_D}{100}\right)^{MS}$

where MS = Month - (month of start)

Table 3-17 Range of Input Parameters for Energy Balance Model

Item	Description	Symbol	Minimum	Range Nominal	Maximum
1.	Blocking Diode Efficiency	η_D	--	0.98	--
2.	Array Utilization Factor	F_U	0.7	0.9	0.95
3.	Battery Wh Efficiency	η_B	0.6	0.75	0.9
4.	Inverter Efficiency	η_R	0.6	0.7	0.95
5.	Line Loss Factor, Inverter to Load Bus (Efficiency)	η_{RL}	0.99	0.98	0.96
6.	Line Loss Factor, Array to Charger (Efficiency)	η_{SL}	0.8	0.9	0.95
7.	Charger Efficiency (Nighttime)	η_{CD1}	0.8	0.9	0.95
8.	(Daytime)	η_{CD2}	0.8	0.9	0.95
8.	Shunt Regulator Efficiency	η_{SR}	0.8	0.95	1
9.	Battery Blocking Diode Efficiency	η_{DB}	--	0.98	--
10.	Boost Regulator Efficiency	η_{BR}	0.7	0.8	0.9
11.	Battery Depth-of-Discharge Constraint	C_D	50%	70%	90%
12.	Rated Battery Capacity, A-h	C_R	150	250	400
13.	Average Battery Discharge Voltage, Vdc	V_D	100	120	140

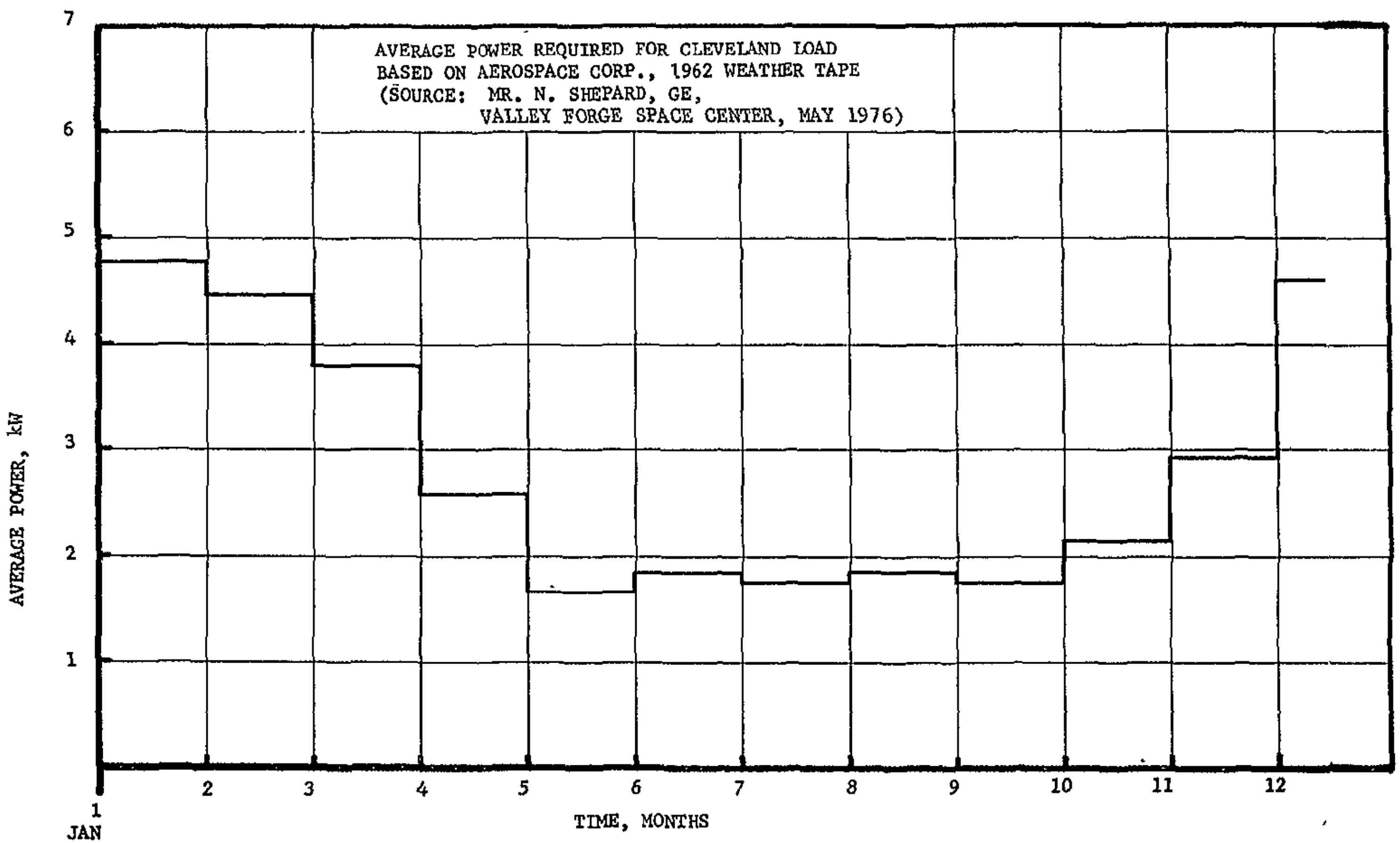


Figure 3-7 Typical Monthly Load Profile All Electric Residence (Including Heat Pump) for Cleveland, Ohio

3.5.5 Geographical Sites

The five sites selected by NASA-LeRC for the sensitivity analysis are as follows:

(1) Cleveland, Ohio;

(2) Denver, Colorado;

(3) Blue Hill, Massachusettes;

(4) Gainesville, Florida; and

(5) Phoenix, Arizona.

The geographical coordinates, time zone number, and panel tilt angle ranges for the five sites are shown in Table 3-18. These sites are generally representative of the divergent climatic conditions that exist in different regions of the United States.

3.6 Sensitivity Analysis Results and Discussion

The sensitivity analysis was performed on: (1) four electrical power system (EPS) candidates described previously to select a configuration for detailed analysis; (2) insolation characteristics; and (3) solar array, battery, inverter, and system performance for the selected EPS configuration. The approach used was to develop parametric data on key performance parameters. From these data, the most sensitive factors were identified.

3.6.1 EPS configurations

The quantitative comparison of the various EPS configurations is best illustrated using the simplified system efficiency as a measure of overall EPS performance. This efficiency is defined as 1/K, where

$$K = \frac{P_{SA}}{P_{BUS}} \qquad [1]$$

and

$$\frac{P_{SA}}{P_{BUS}} = \frac{t_N/t_D}{\gamma_1} + \frac{1}{\gamma_2} \qquad [2]$$

where γ_1 = product of component and system efficiencies during night duration

γ_2 = product of component and system efficiencies during day duration

Table 3-18 Range of Time-Independent Parameters for Five Selected Sites

	DENVER			CLEVELAND			BLUE HILL			GAINESVILLE			PHOENIX		
	Min.	Nom.	Max.	Min.	Nom.	Max.	Min.	Nom.	Max.	Min.	Nom.	Max.	Min.	Nom.	Max.
Latitude, Lat.	---	39°44.4'	---	---	41°29.8'	---	---	42°13'	---	---	29°39.6'	---	---	33°27.3'	---
Longitude, Lon	---	104°59.3'	---	---	81°42.0'	---	---	71°07'	---	---	82°19.8'	---	---	112°04.4'	---
Panel Tilt Angle,	9.5°	39.5°	70°	11.1°	41.5°	71.5°	12.2	42.2	72.2	-0.4	29.6°	59.6°	3.45°	33.45°	63.45°
Time Zone Number, T_{ZN}*	---	7	---	---	5	---	---	5	---	---	5	---	---	7	---

* Time zone numbers correspond to time zones as follows:

5 - Eastern

6 - Central

7 - Mountain

8 - Pacific

P_{SA} = Average solar array power output during daylight duration

P_{BUS} = Average bus power output capability.

The term K thus reflects the individual component efficiencies, system loss factors, and day and night durations. It is based on the energy balance relationship which is discussed in detail in Appendix A. Note that K is independent of solar irradiance and assumes a constant day and night load.

Figure 3-8 shows the system efficiency versus daylight time available for the four EPS configurations with and without the batteries. The efficiency of the configuration with the battery increases linearly with daylight duration. The configuration without the battery is independent of the daylight duration. The plot also indicates that Configuration III has the highest efficiency. Thus, Configuration III was selected as a baseline for detailed sensitivity analysis purposes.

Another significant result indicated in Figure 3-8 is the large sensitivity of the system efficiency to the use of a battery. For Configuration III, the system efficiency is about 56% without the battery and between 17 and 34% with the battery. From the standpoint of the solar array, these efficiencies simply mean that the solar array size required for the configuration with the battery varies between 3.3 to 1.7 times the size of the array for the configuration without the battery.

Figure 3-9 shows the solar array output versus average bus power capability. Without the battery the lowest ratio between peak, solar array output power and bus power capability is approximately 5.9:1. This means that an average 24-hour bus power capability of 1 kW requires an average solar array output of 5.9 kW for the following conditions:

Daylight Duration	= 9 hours
Night load	= 1100 W
Average solar intensity	= 50 mW/cm^2
Number of 1.219m x 1.219m (4 ft x 4 ft) subarrays	= 90

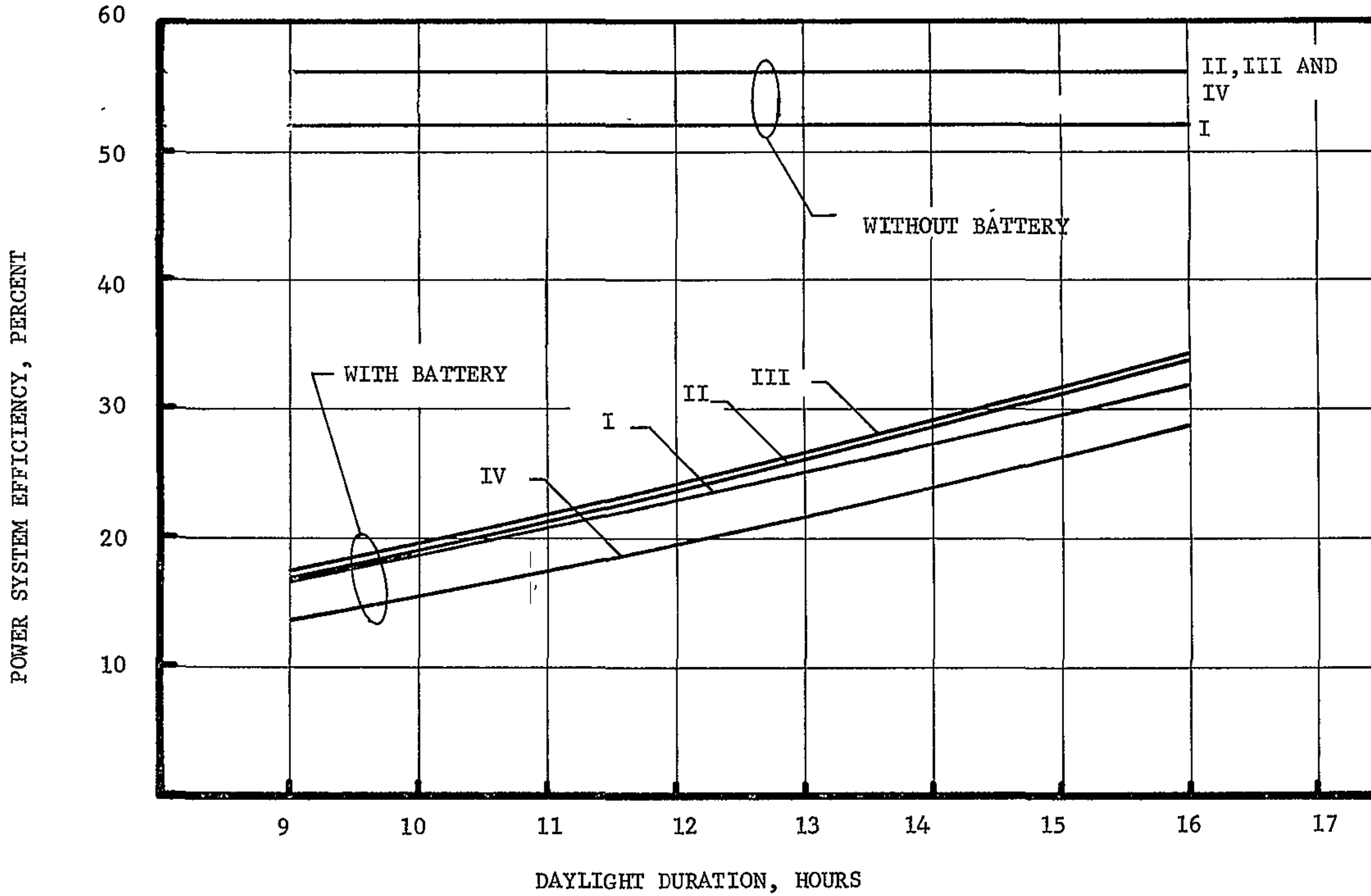


Figure 3-8 System Efficiency as a Function of Daylight Duration for Four EPS Candidates

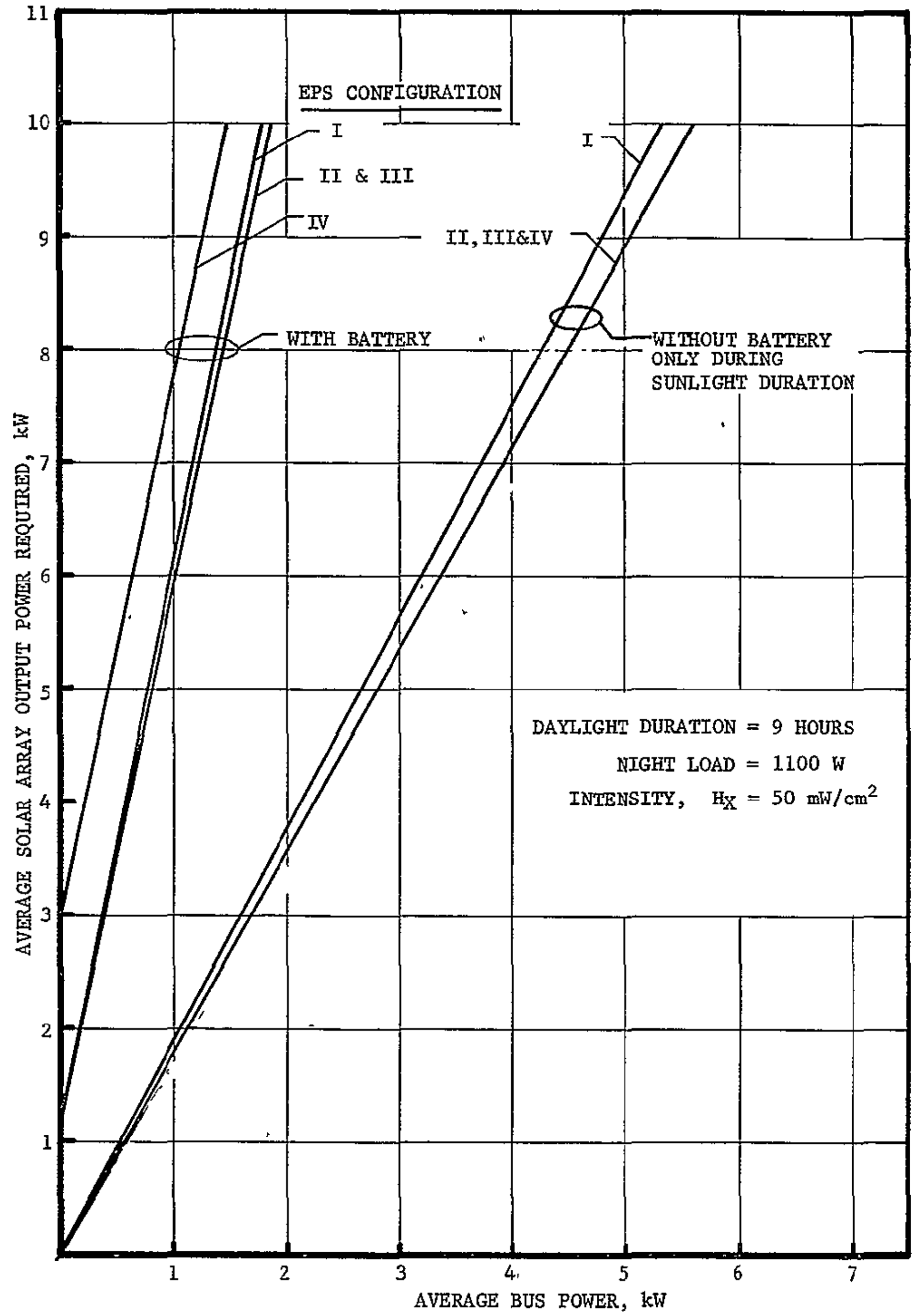


Figure 3-9 Average Solar Array Output Power Required as a Function of Average Bus Power Demand

The minimum ratio for the no-battery case is approximately 1.8:1. For an average nine hour (daylight duration) bus power capability of 1 kW, an average 1.8 kW solar array power output is needed. The battery configurations support a 24 hour bus while the bus capability for the configuration without a battery is available only during the daylight period. The ratio of solar array output power to average bus power capability is a function of daylight duration for the battery case. For a constant solar intensity, this ratio can vary by as much as a factor of two. The average bus power capability for the four EPSs given as a function of average inverter efficiency in Figure 3-10. The results are similar to those shown in Figure 3-9, with Configuration III yielding the highest output. Figure 3-10 shows that the available bus power based on a fixed array size is more sensitive to the inverter efficiency without the battery. This plot also indicates that a no-battery configuration results in a higher available power at a lower inverter efficiency. Also apparent in Figure 3-10 is the sensitivity of the configuration output to a change in the solar array utilization factor, F_U. As F_U is changed from 0.9 to 0.75 at the stated conditions and an inverter efficiency of 70%, the average bus power capability for Configuration III with the battery will be reduced from 580 watts to 380 watts or about 34.5%. These results are parametric and do not reflect changing day duration, load, or solar intensity.

3.6.2 Solar Irradiance

Comparison of SIM Results with Historical Data. Figures 3-11 through 3-15 show the results of the SIM calculations of daily integrated solar irradiance (for a one-year period), for each of the five sites. Also shown in these figures, is the corresponding historical data - measured monthly mean daily solar irradiance. In some cases (such as the Phoenix results for the months of April, May, June, July), the SIM results exhibit step type changes between certain months. This results because the SIM uses monthly inputs of percent sunshine, which the Phoenix, Arizona case shows can change markedly from month to month.

A quantitative comparison of the monthly SIM results with the historical data is shown in Figure 3-16. The mean error (for a total year) ranges from a low of 2.8% for Phoenix to a high of 10.9% for Gainsville. The Denver and Phoenix errors are the lowest, 3.8 and 2.8% respectively. This could be because the clearness number for Denver was obtained by actual measurements. Since Denver and Phoenix have similar atmospheric conditions, the same clearness number was used for Phoenix. By inspecting Figure 3-16, it appears evident that there is a trend for positive errors (SIM results too

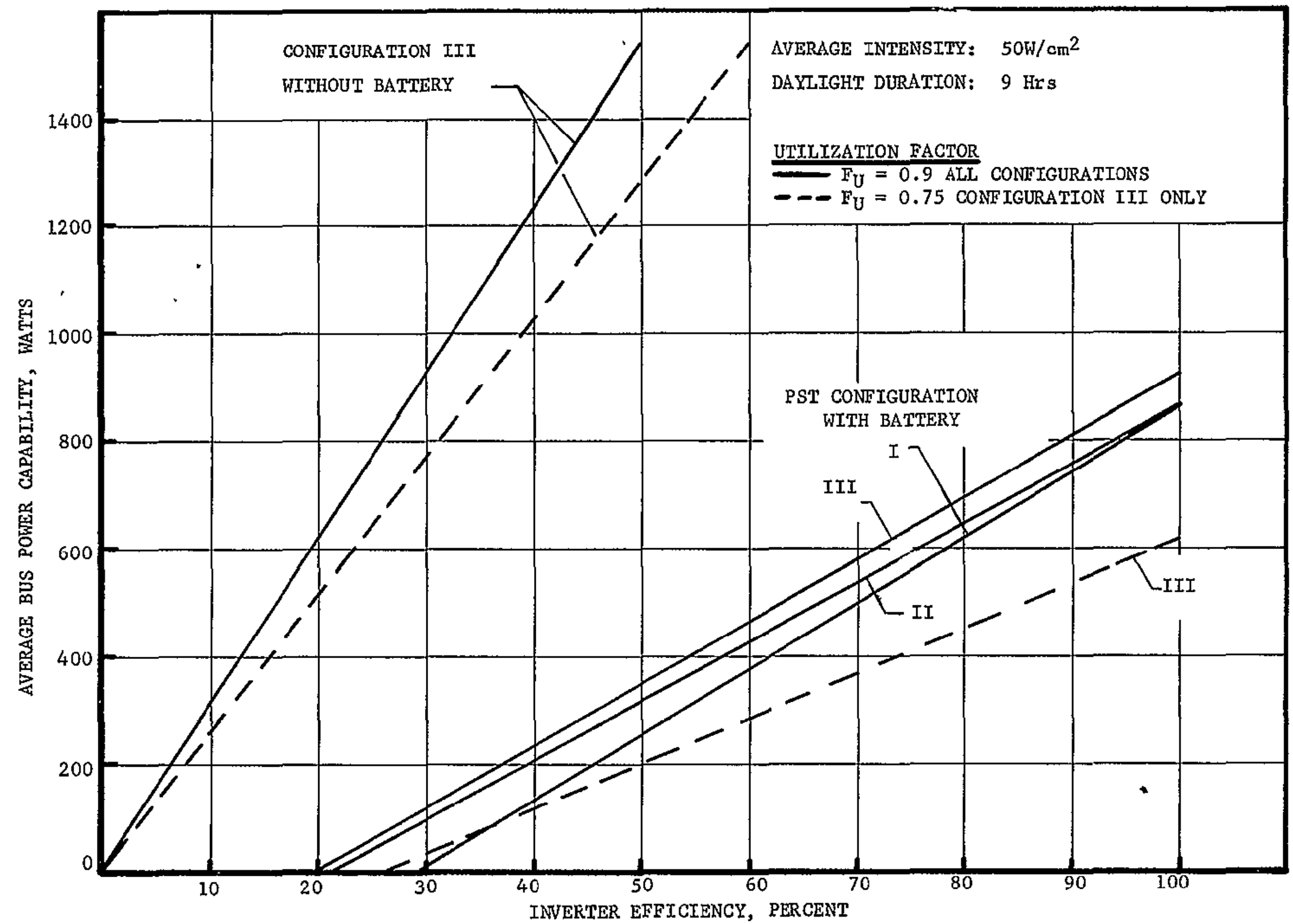


Figure 3-10 Average Bus Power Capability Versus Average Inverter Efficiency

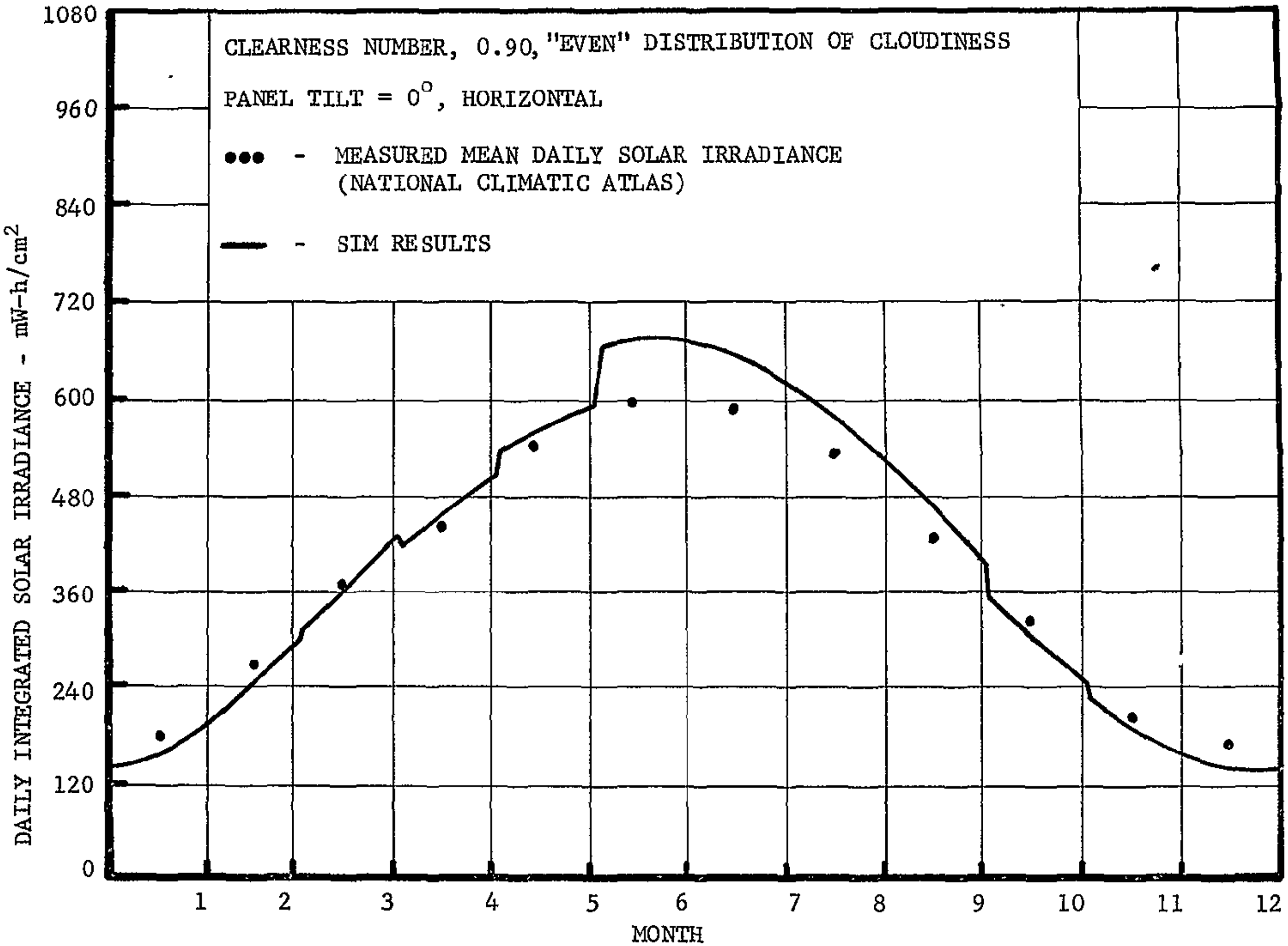


Figure 3-11 Comparison of Measured Data with SIM Results for Blue Hill, Massachusetts

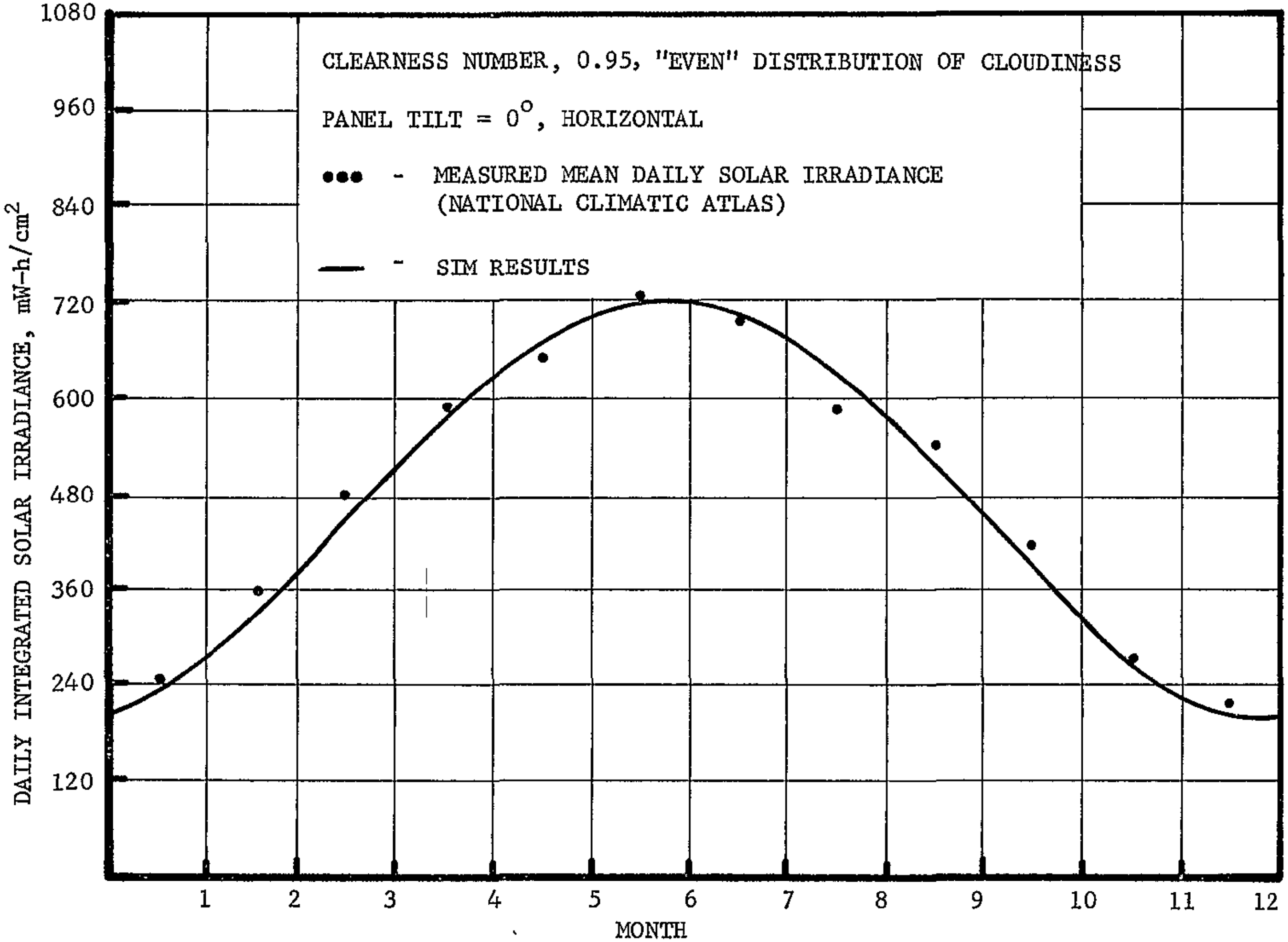


Figure 3-12 Comparison of Measured Data with SIM Results for Denver, Colorado

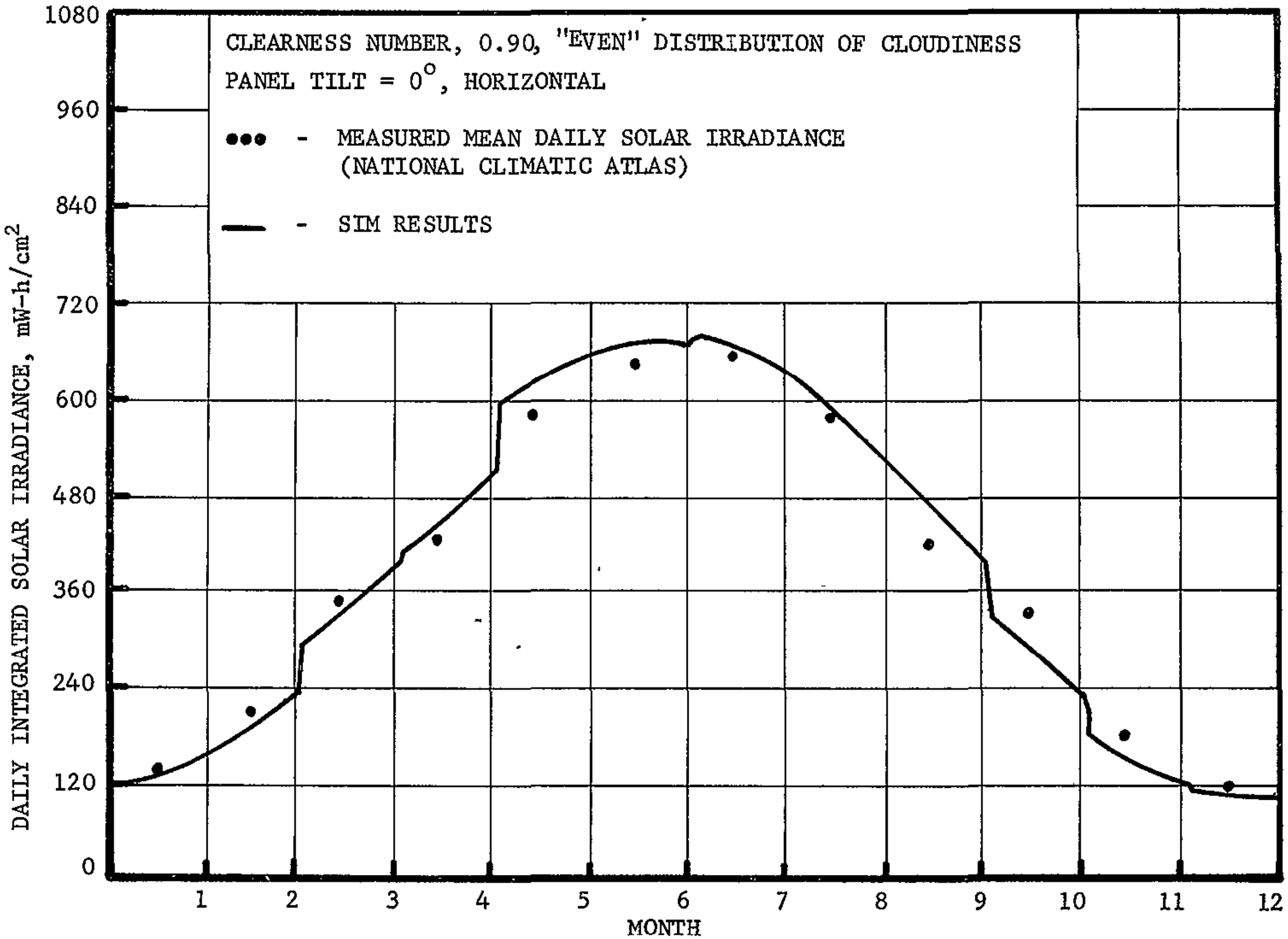


Figure 3-13 Comparison of Measured Data with SIM Results for Cleveland, Ohio

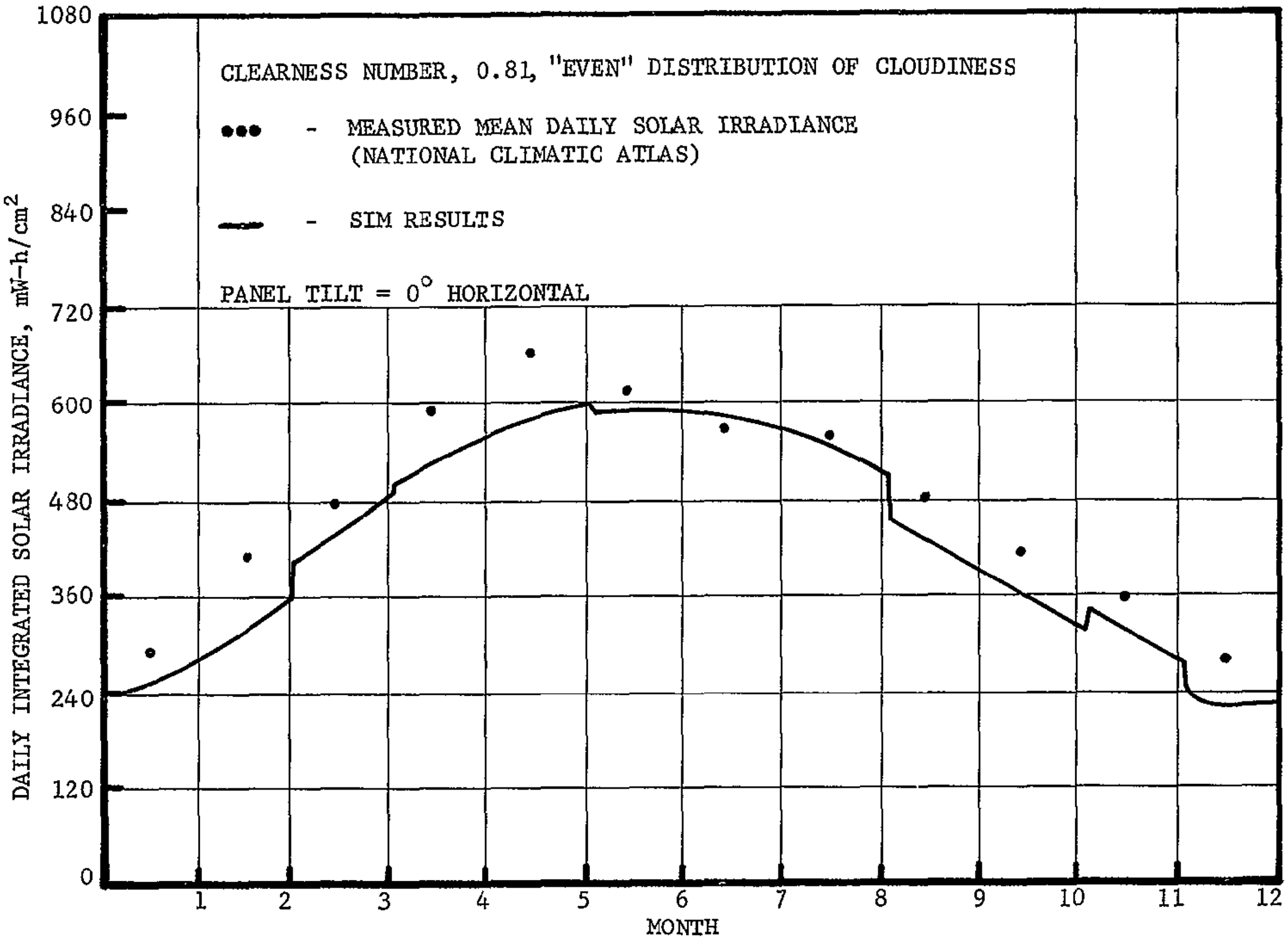


Figure 3-14 Comparison of Measured Data with SIM Results for Gainesville, Florida

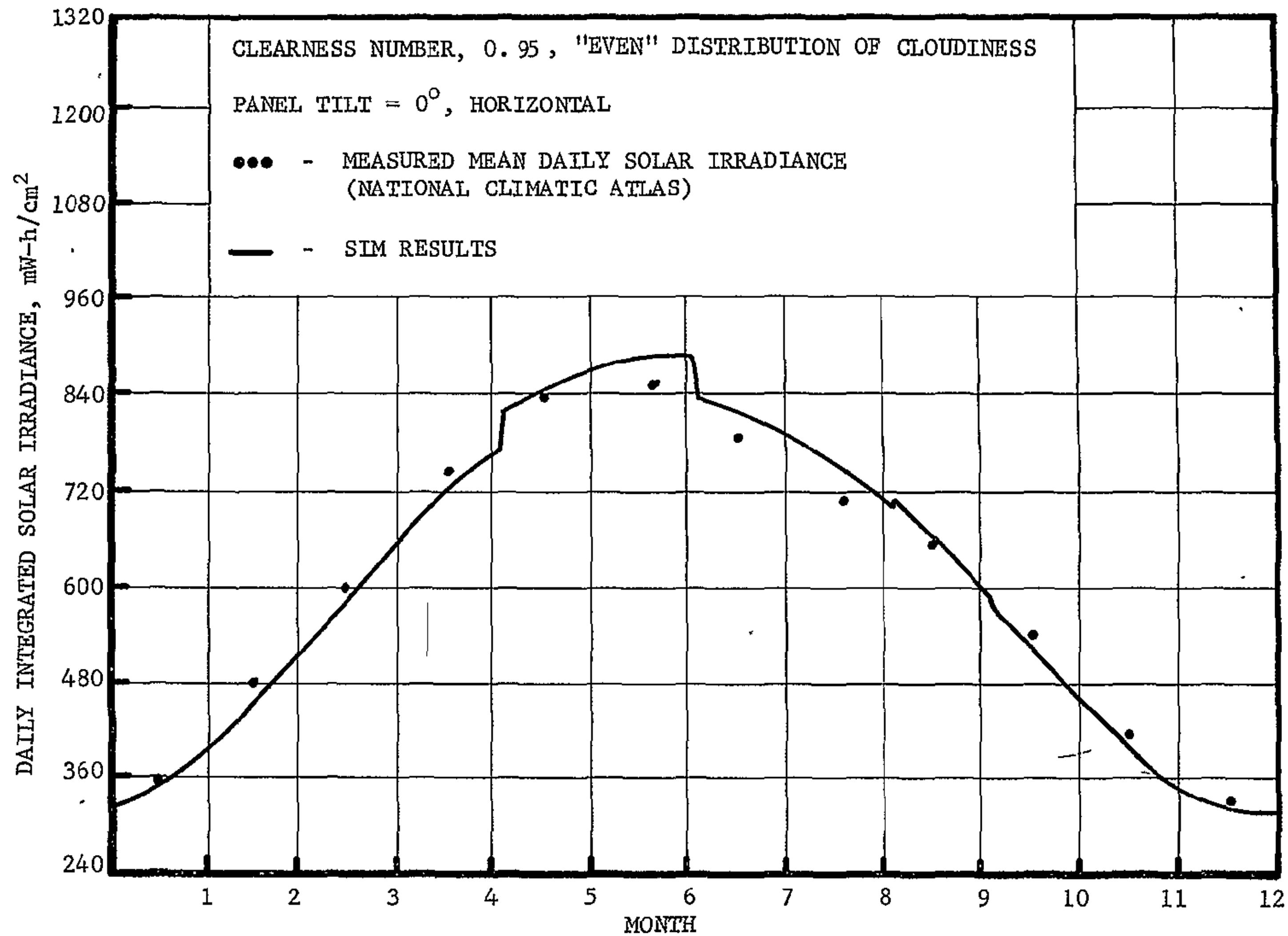


Figure 3-15 Comparison of Measured Data with SIM Results for Phoenix, Arizona

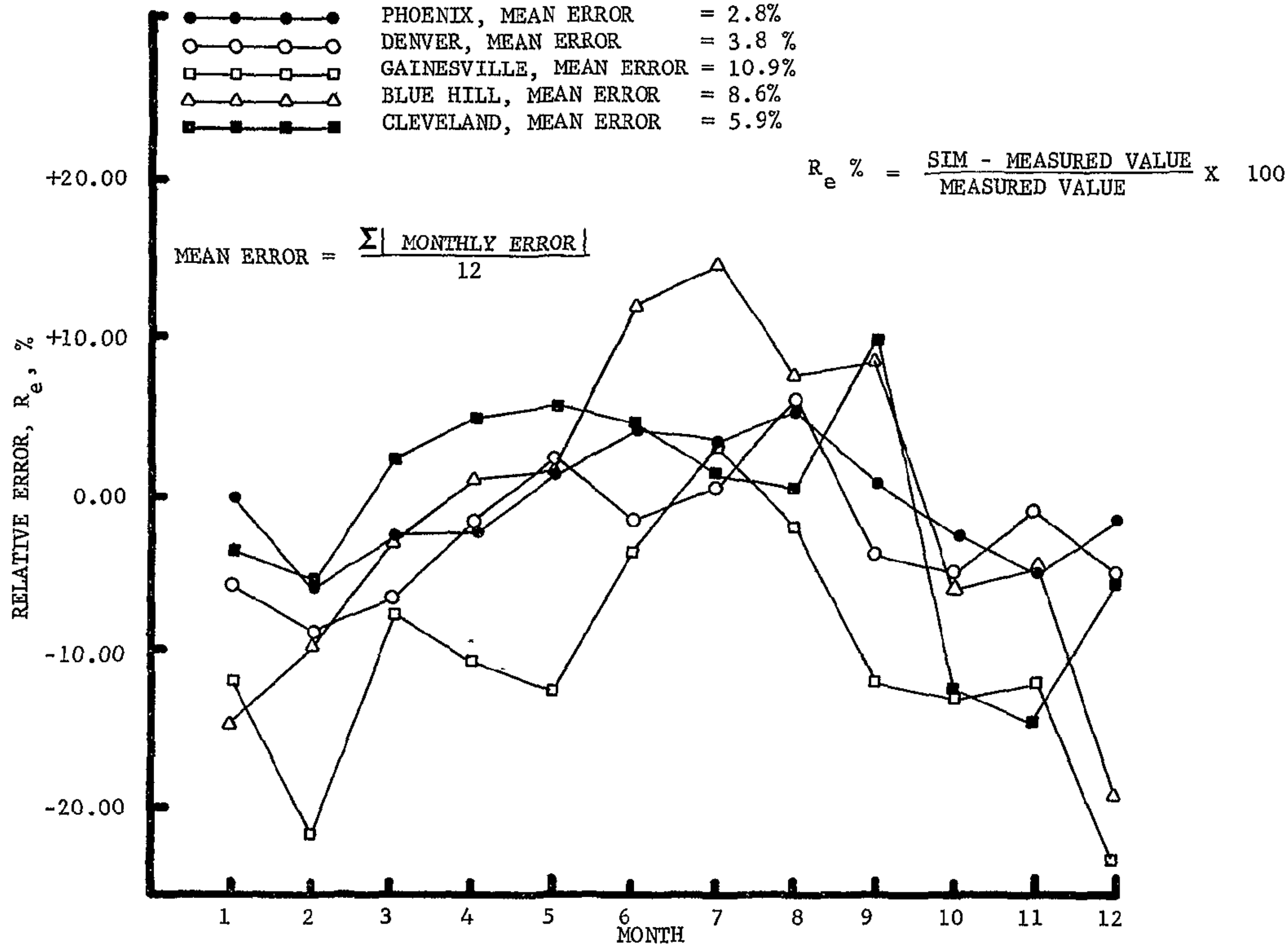


Figure 3-16 Relative Error of SIM Results for Five Geographical Sites

high) during the middle months (May through September) and negative errors (SIM results too low) during the first and latter months (January to March and October to December). Figure 3-17 shows a plot of the number of errors (for positive and negative) versus month of the year. As can be seen, there exists a very obvious trend for positive errors during the middle months and negative errors for the first and latter months. This can vary for a given site. For example, the Gainesville, Florida SIM results have predominant negative errors. The Cleveland, Ohio SIM results have predominant positive errors. The clearness number could be one explanation for these error trends and characteristics. The overall trend of positive SIM errors during the middle months (spring and summer) could be due to the clearness numbers being too high which resulted in the SIM results being too high. Conversely, the negative SIM errors during the first and latter months (fall and winter) could be due to the clearness numbers being too low. This would be in general agreement with the atmospheric phenomenon of increasing atmospheric clarity (higher clearness number) during the fall and winter seasons, and decreasing atmospheric clarity (lower clearness number) during the spring and summer seasons.

The consistently negative errors for Gainesville could be explained by too low a clearness number. The consistently positive errors for Cleveland could be explained by too high a clearness number. As shown later, the sensitivity analysis of the clearness number showed that it uniformly adjusts the overall level of solar irradiance. Therefore, it is a likely candidate for explaining the results just discussed. In addition, since it is an input variable, it can be adjusted to provide an extremely close agreement between SIM results and historical data. This could be done by successive trial and error of comparisons between SIM results and historical data.

A comparison of all sites is shown in Figure 3-18. As can be seen, very definite monthly features and more general seasonal trends exist. For example, if one compares Gainesville with Blue Hill and Cleveland, it can be seen that Gainesville has higher solar irradiance levels during the fall, winter, and early spring, whereas Blue Hill and Cleveland have higher levels during the summer months. The Denver profile of solar irradiance is characterized by an extremely uniform monthly dependence. This is due to Denver's uniform monthly percent sunshine. A comparison of the total, yearly, integrated solar irradiance is shown in Figure 3-19.

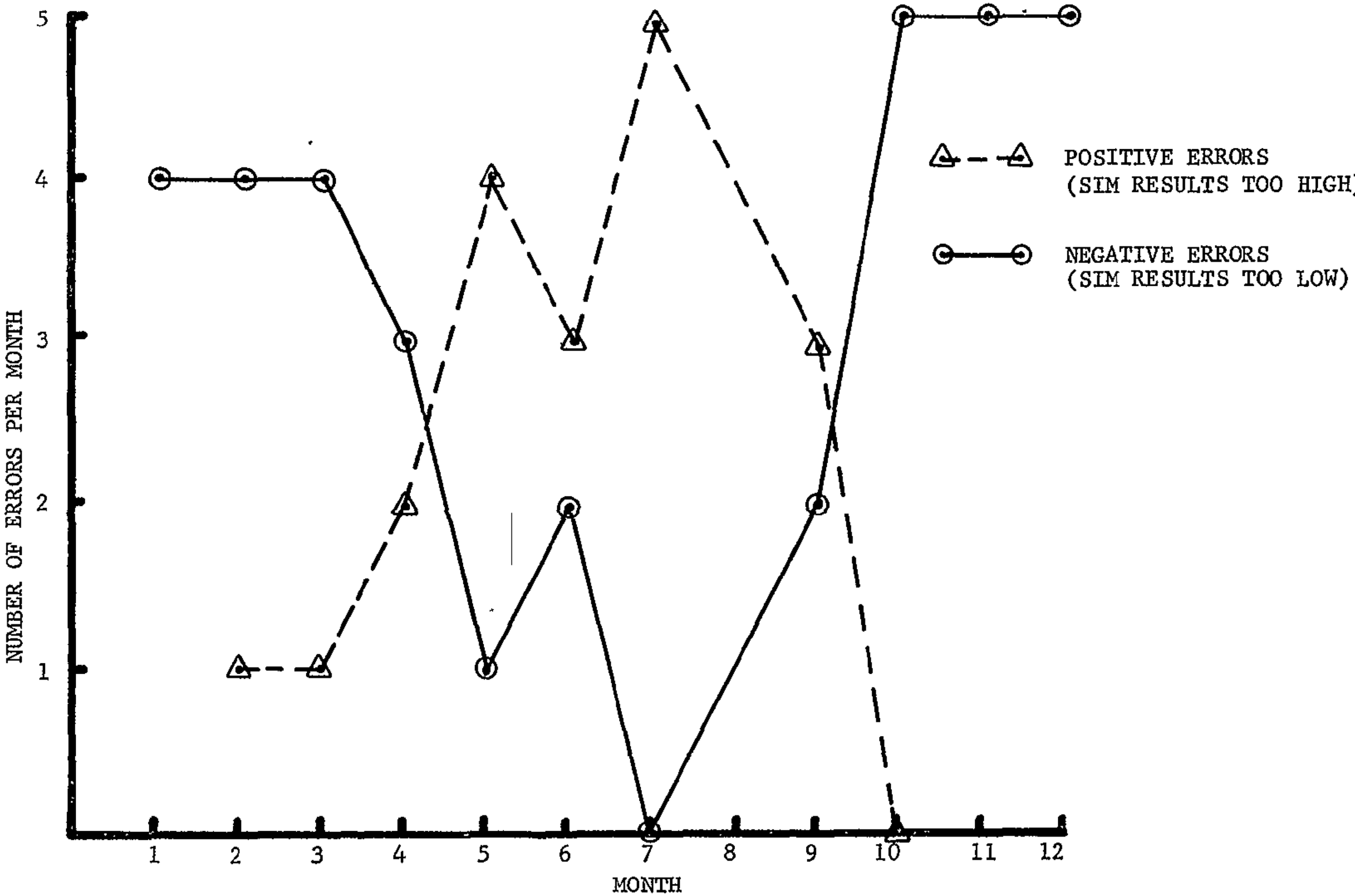


Figure 3-17 Comparison of SIM Positive and Negative Errors

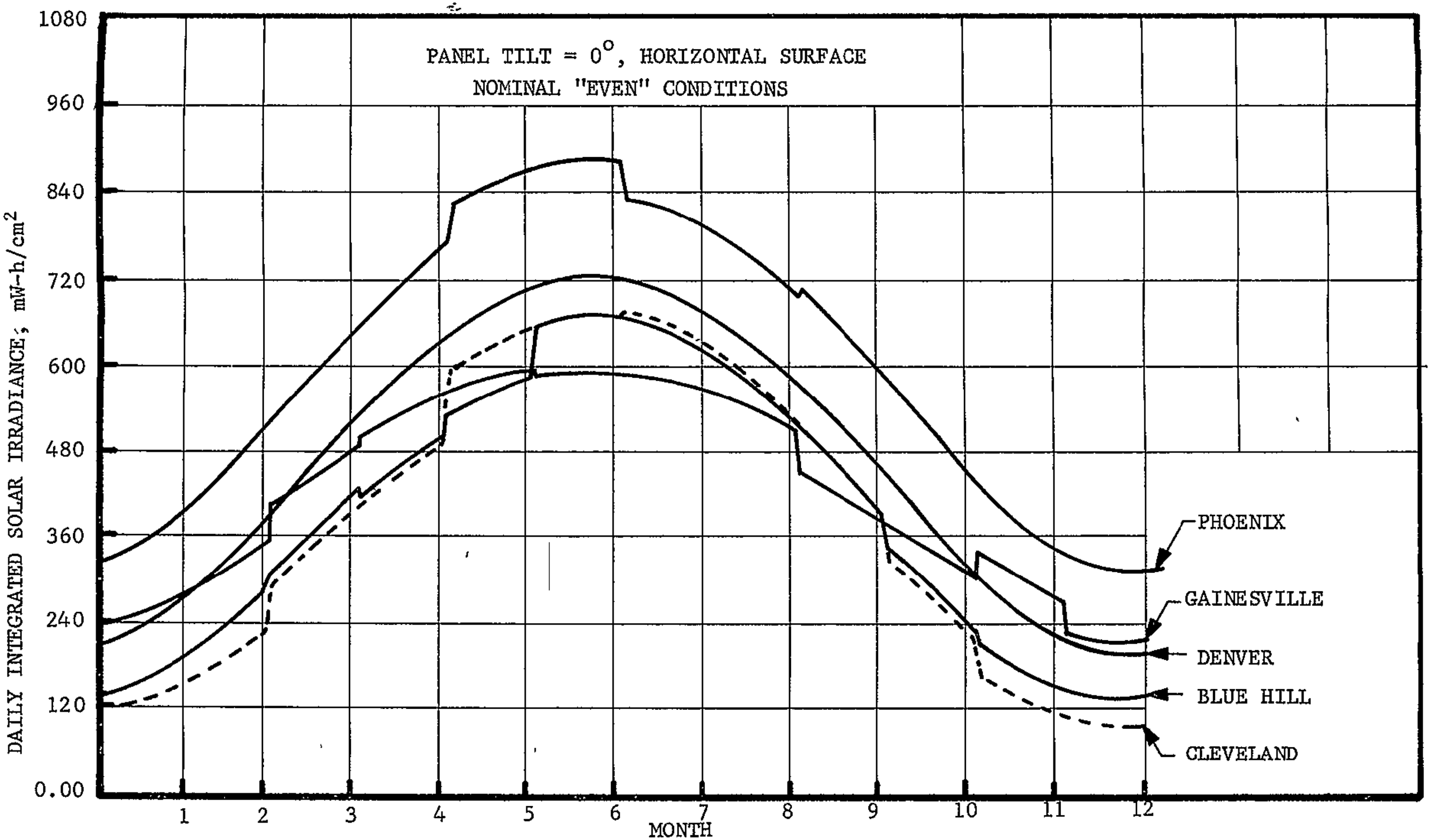


Figure 3-18 SIM Calculations of Daily Integrated Solar Irradiance for Five Geographical Sites

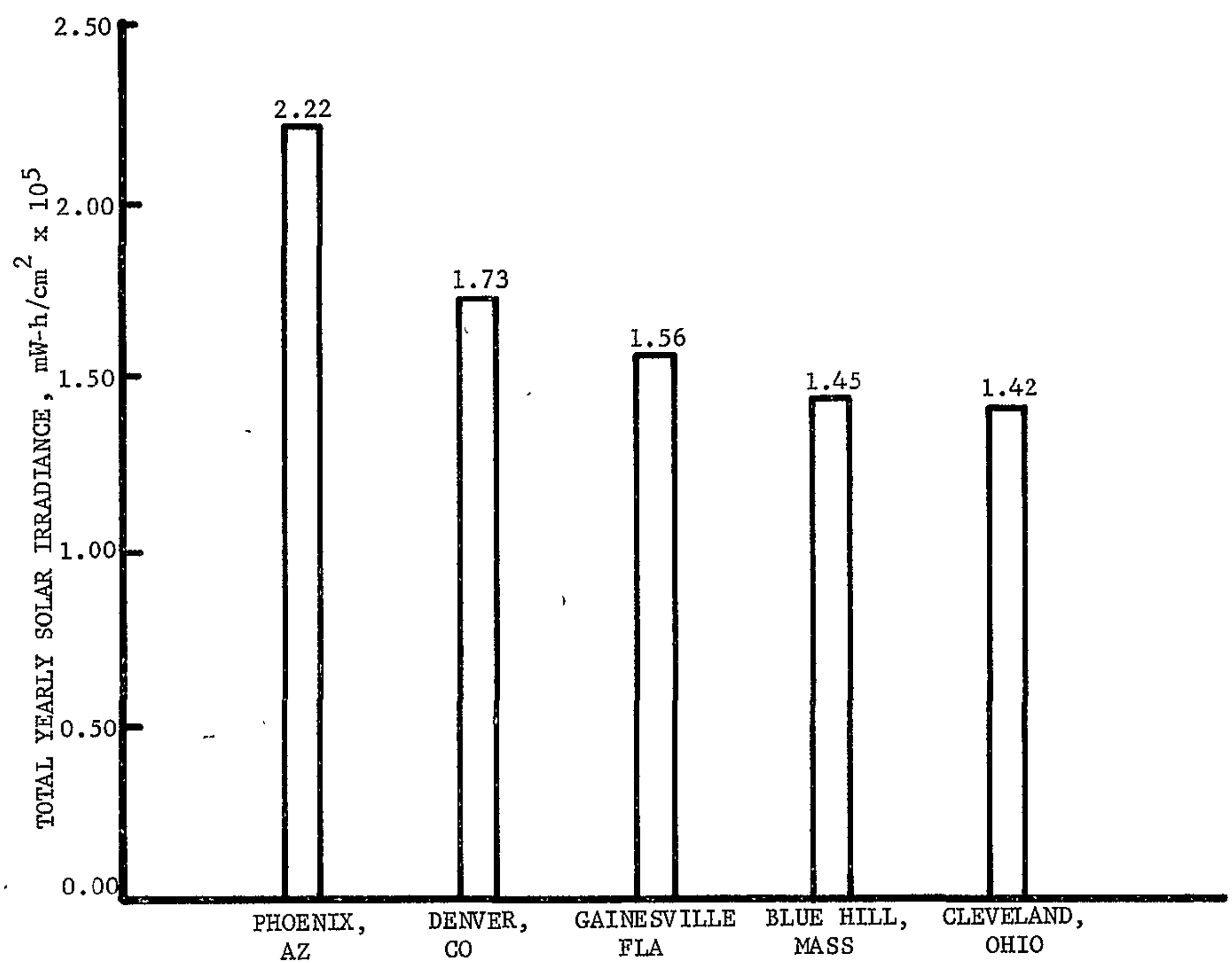


Figure 3-19 Comparison of Yearly Solar Irradiance for Five Geographical Sites

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Clearness Number - The dependence of daily integrated solar irradiance on clearness number for a 100% clear day definition is shown in Figure 3-20. As can be seen, the clearness number affects the overall level of solar irradiance with the greatest impact occurring during the middle months. A similar comparison is shown in Figure 3-21 for a nominal "even" distribution of cloudiness. The effects of the clearness number for this day definition are similar to the 100% clear conditions. Figure 3-22 shows the dependence of the total yearly solar irradiance on the clearness number for both day definitions. Also shown is a tabular listing of the relative impact of clearness number. For clear conditions, the relative impact is linear, i.e.; the total yearly irradiance is directly proportional on a one-to-one basis to the clearness number. This means that if the clearness number is increased by 20% the total yearly solar irradiance will increase by 20%. For the nominal "even" day definition, this relationship is slightly more sensitive than a one-to-one linear relationship. As can be seen, an increase of 11.8% in the clearness number results in a 13.9% increase in total yearly solar irradiance. These results point out that the clearness number is a major determinate of the resultant SIM predictions of solar irradiance.

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Percent Sunshine - Figure 3-23 shows the dependence of the daily integrated solar irradiance on percent sunshine for a nominal "even" cloudiness distribution for Denver, Colorado. The corresponding plot for a nominal "fixed" cloudiness distribution is shown in Figure 3-24. As can be seen, the percent sunshine has a marked impact on the daily integrated irradiance. In addition, this impact is similar for both types of day definitions. Figure 3-25 shows the dependence of total yearly irradiance for both types of day definitions, on percent sunshine. In the region from 20 to 40% sunshine, for each 1% increase in percent sunshine there is an 8.2% increase in yearly irradiance. In the region from 60 to 80% sunshine, for every 1% increase in percent sunshine, there is a 2.5% increase in yearly irradiance. Hence, the percent sunshine strongly impacts the total yearly and daily integrated solar irradiance.

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Ground Reflectivity - Figure 3-26 shows the dependence of the daily integrated solar irradiance on ground reflectivity for a panel tilted at the site latitude. As can be seen, a definite impact exists with the greatest impact occuring during the middle months. The dependence of the total yearly solar irradiance, for a panel tilted at the site's latitude, is shown in Figure 3-27. The impact

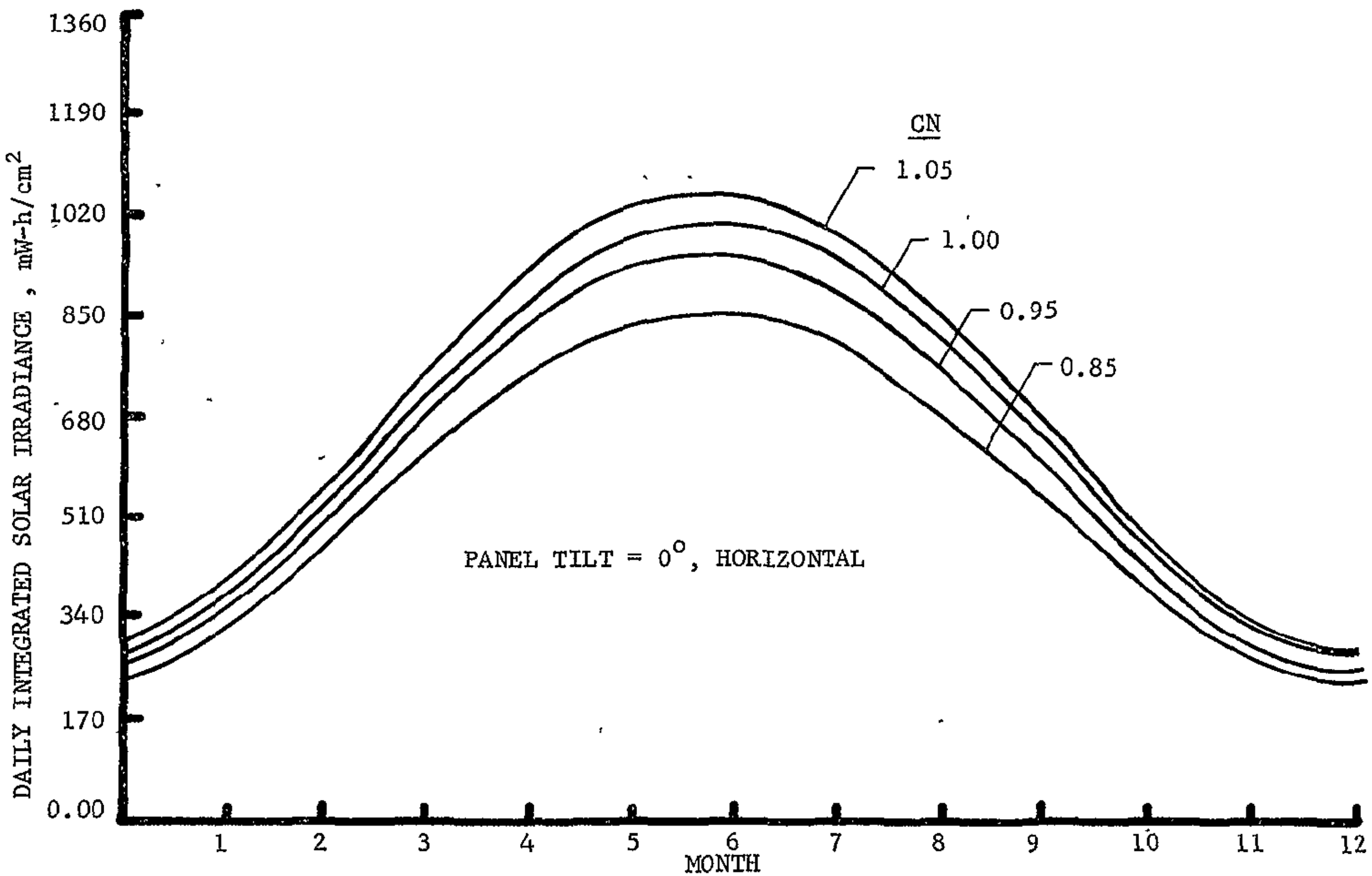


Figure 3-20 Dependence of Daily Integrated Solar Irradiance on Clearness Number for 100% Clear Conditions, Denver, Colorado

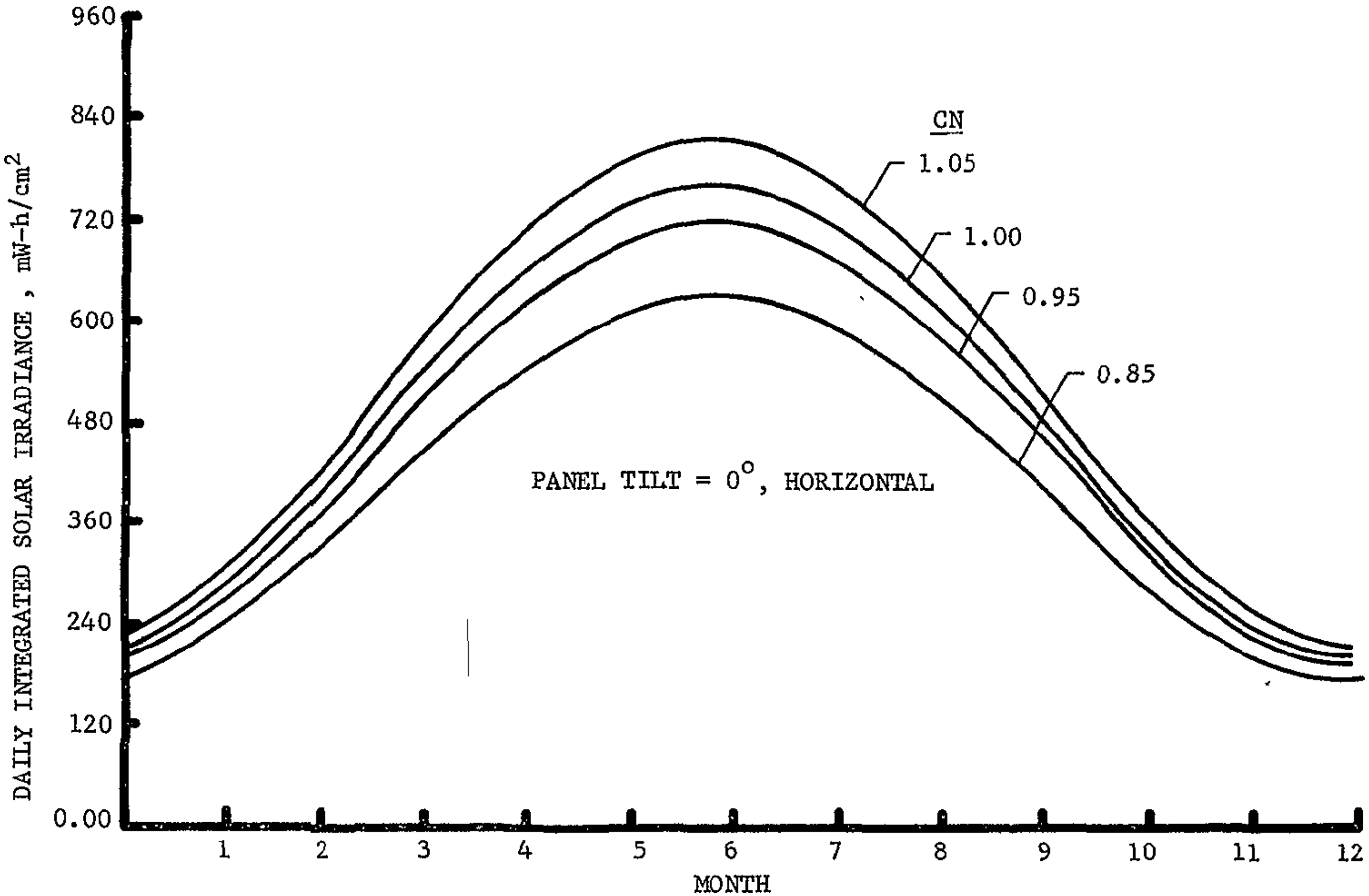
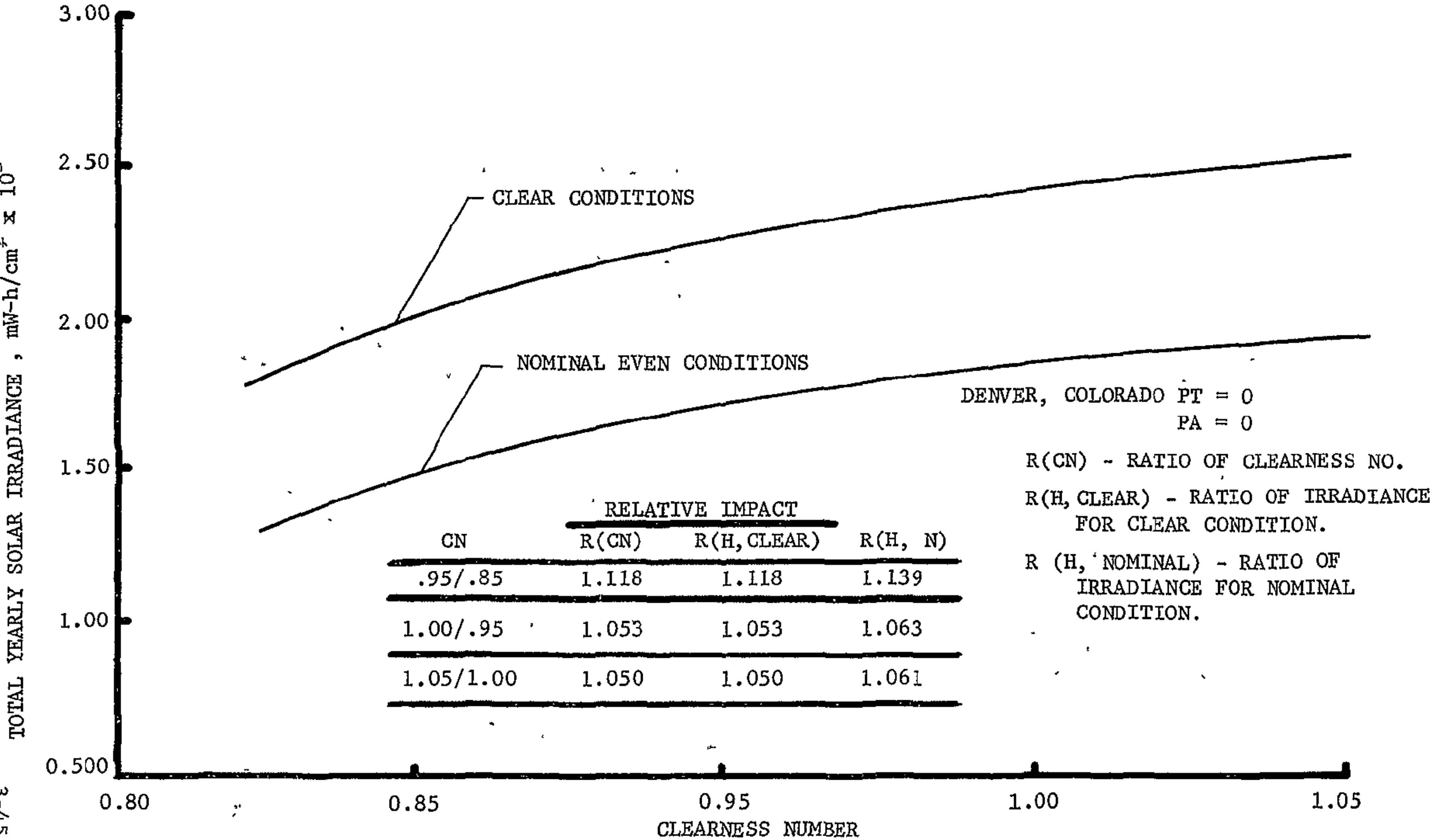


Figure 3-21 Dependence of Daily Integrated Solar Irradiance on Clearness Number of Nominal "Even" Partly Cloudy Conditions, Denver, Colorado



	RELATIVE IMPACT		
CN	R(CN)	R(H, CLEAR)	R(H, N)
.95/.85	1.118	1.118	1.139
1.00/.95	1.053	1.053	1.063
1.05/1.00	1.050	1.050	1.061

Figure 3-22 Sensitivity of Total Yearly Solar Irradiance on Clearness Number for Clear and Nominal "Even" Cloudiness Distribution

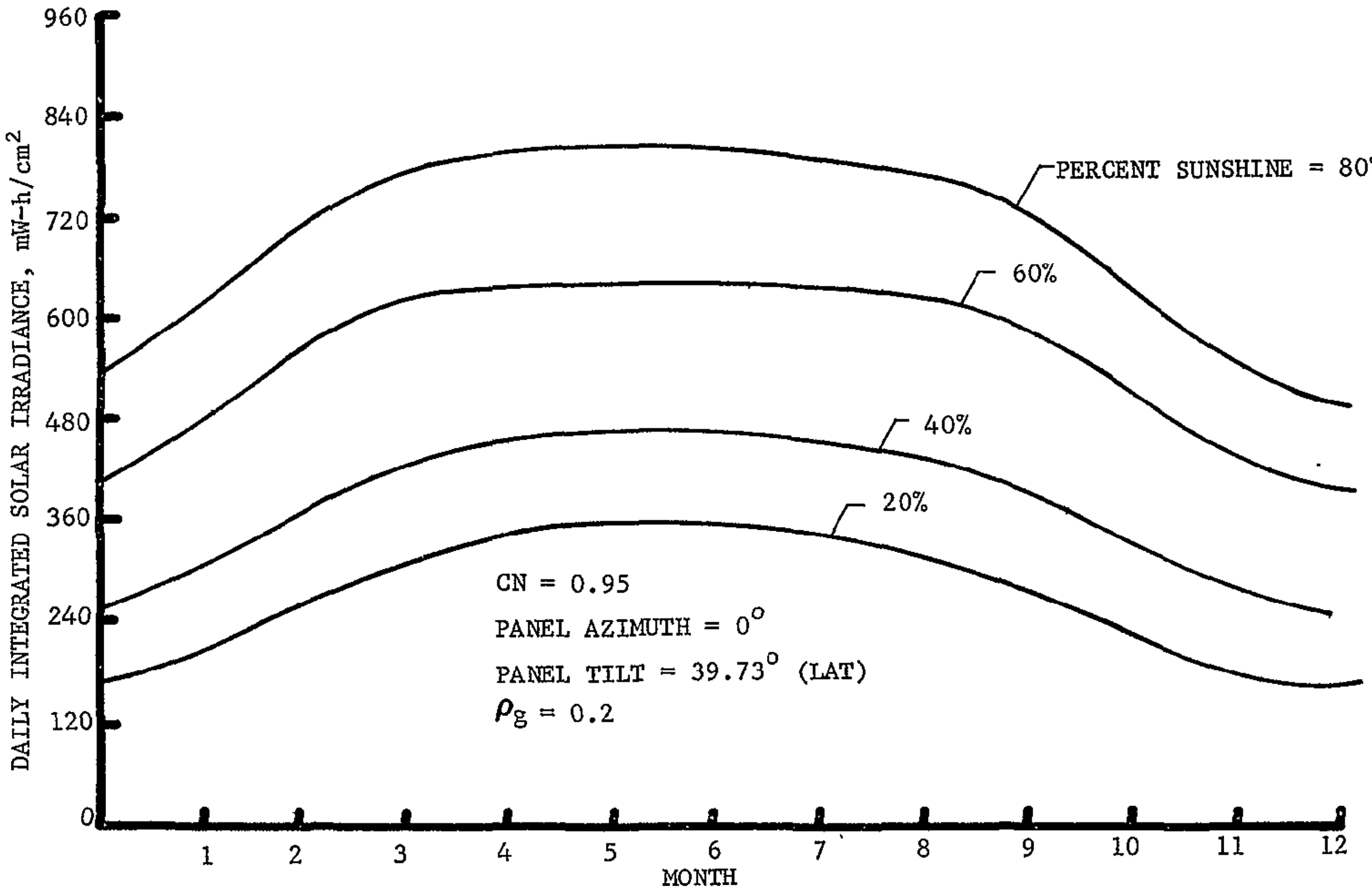


Figure 3-23 Dependence of Daily Integrated Solar Irradiance on Percent Sunshine for Nominal "Even" Distribution of Cloudiness (Denver, Colorado)

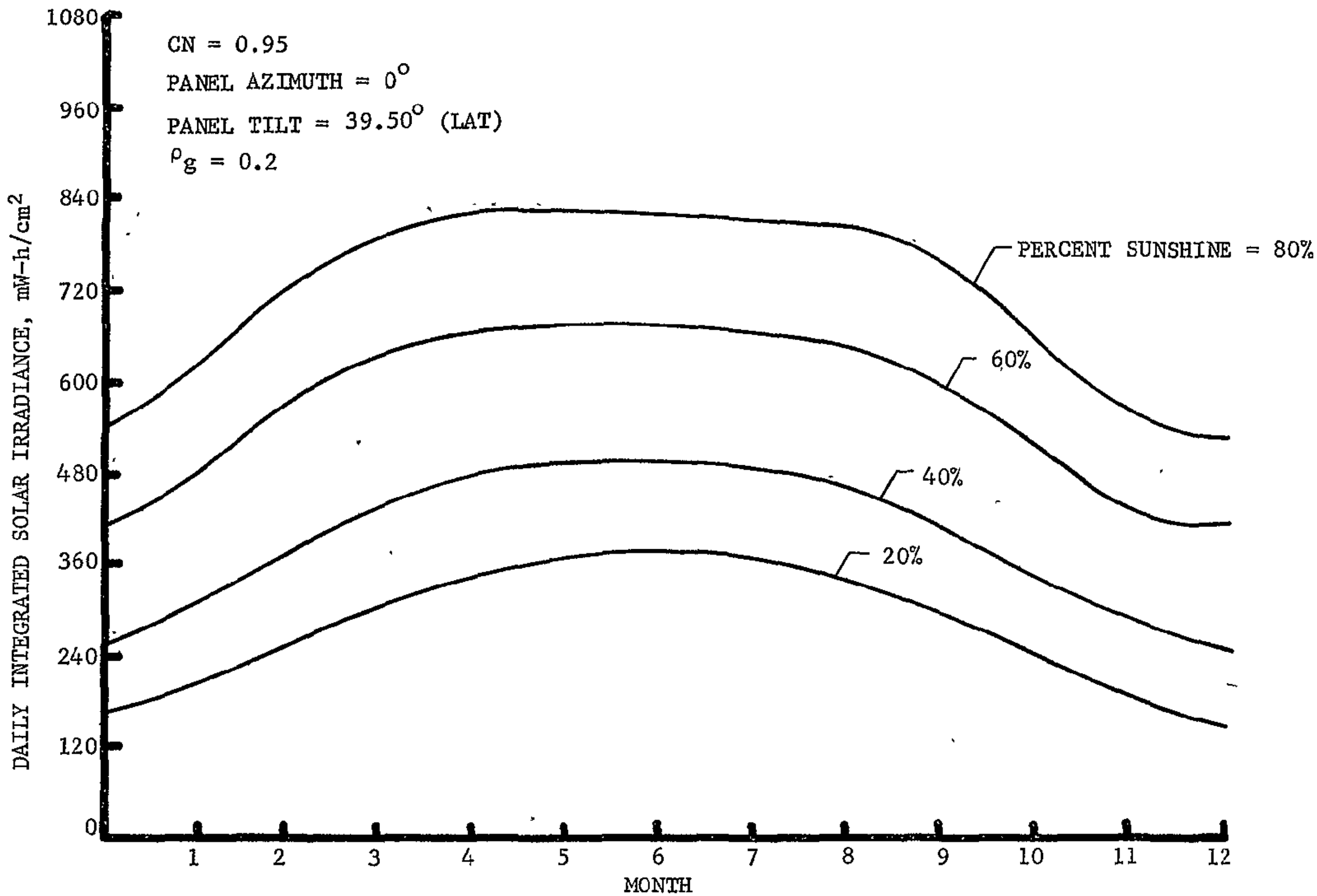


Figure 3-24 Dependence of Daily Integrated Solar Irradiance on Percent Sunshine for Nominal "Fixed" Distribution of Cloudiness (Denver, Colorado)

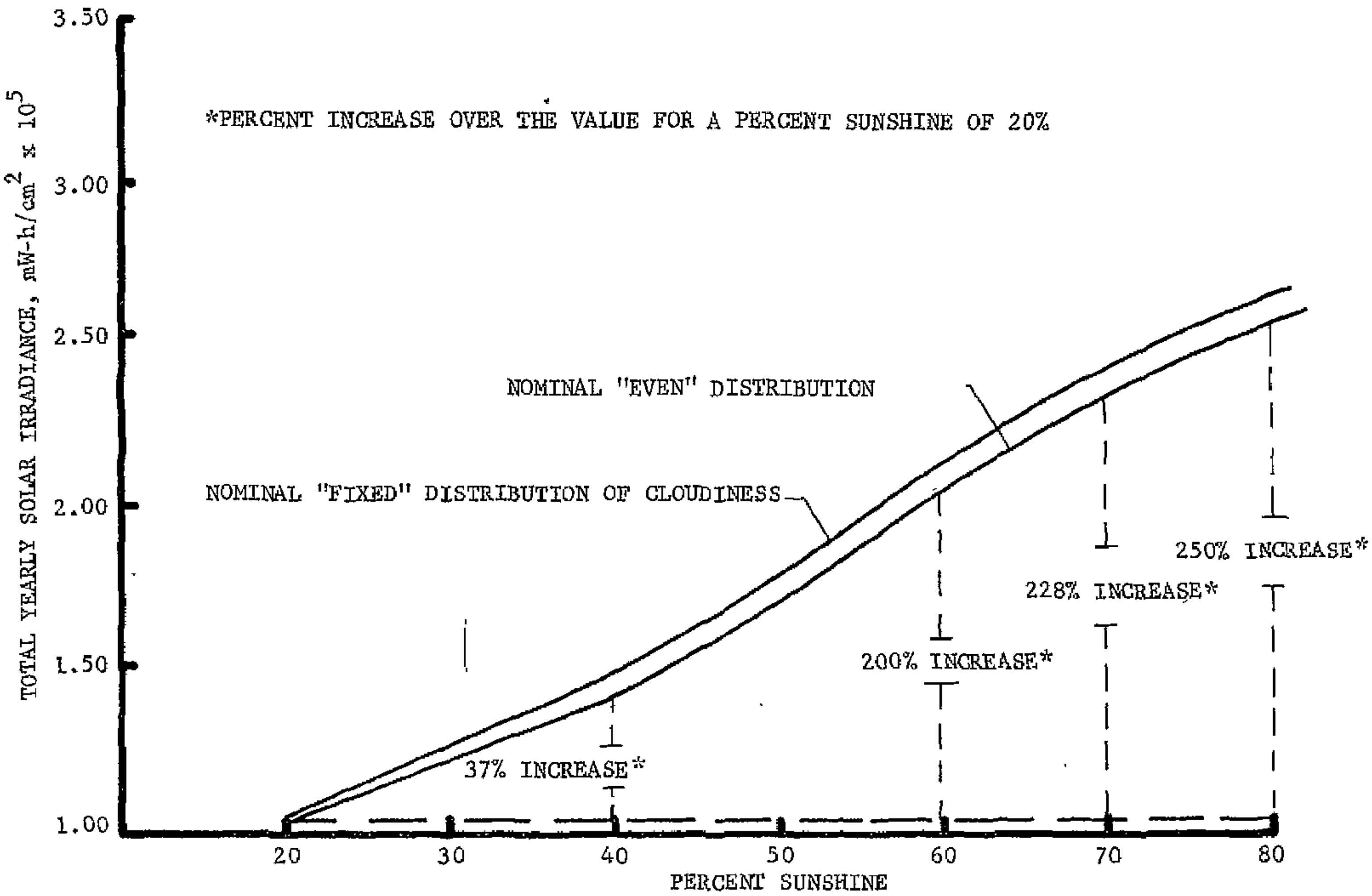


Figure 3-25 Dependence of Total Yearly Solar Irradiance on Percent Sunshine for Nominal "Even" and Nominal "Fixed" Cloudiness Distributions

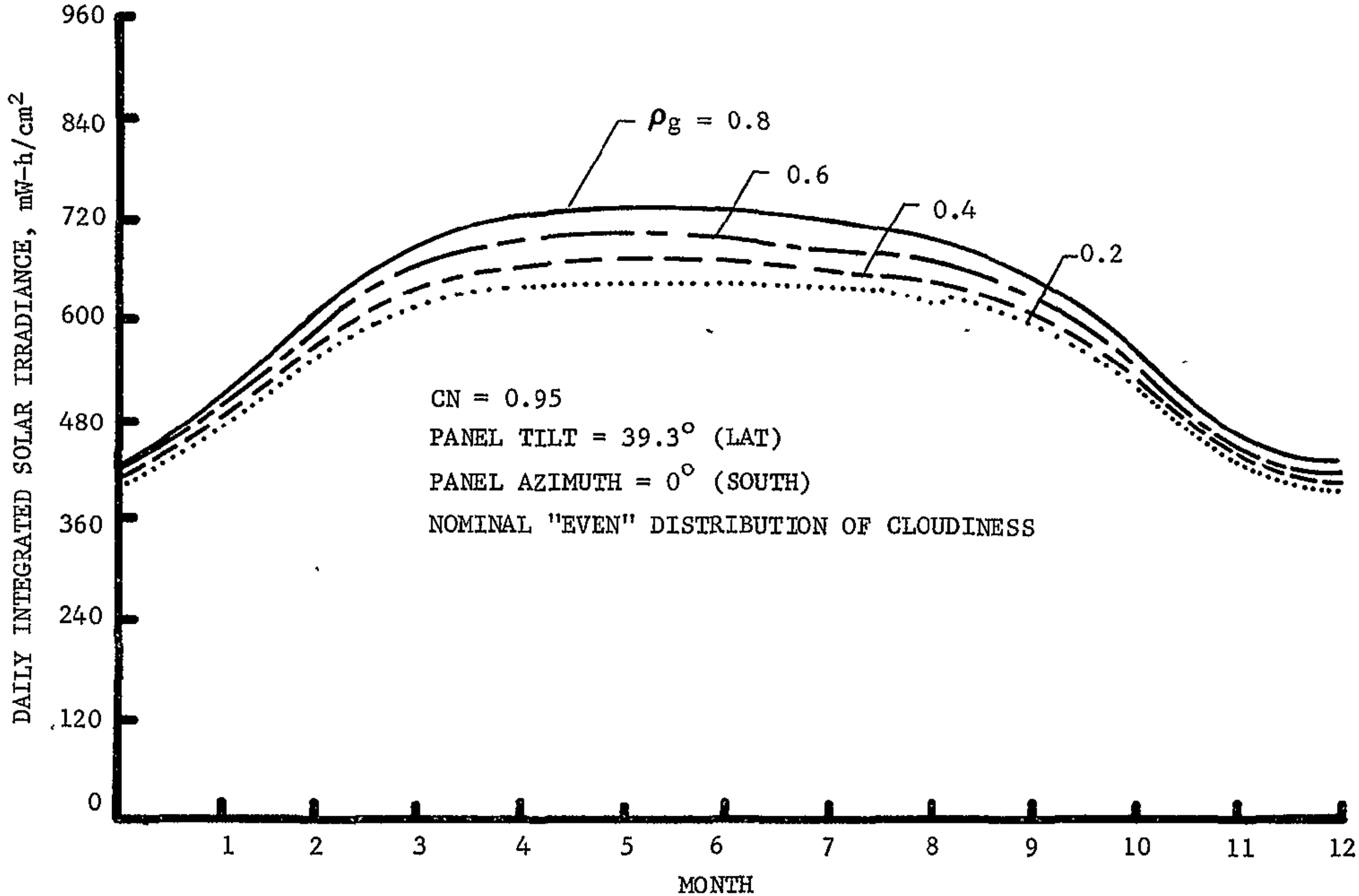


Figure 3-26 Dependence of Daily Integrated Solar Irradiance on Ground Reflectivity for a Panel Tilted at the Site Latitude, Denver, Colorado

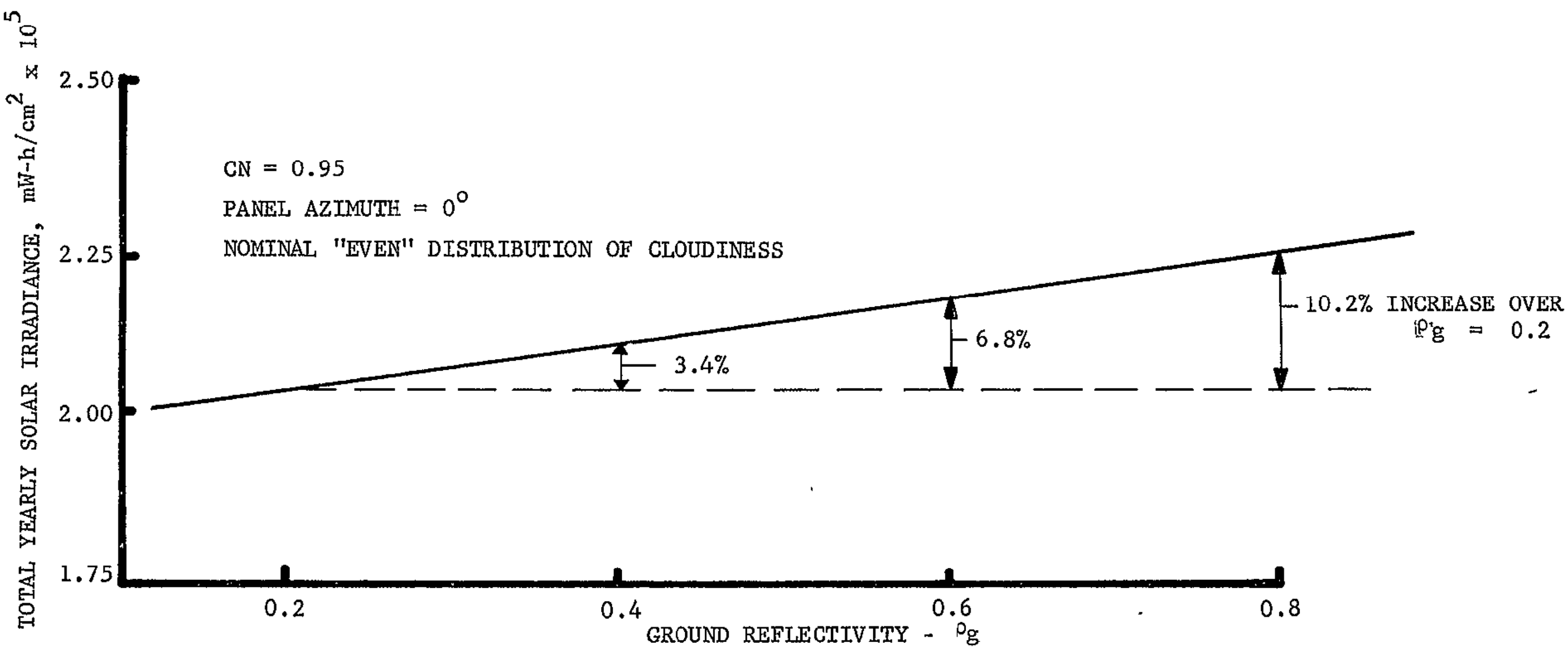


Figure 3-27 Dependence of Total Yearly Solar Irradiance on Ground Reflectivity for a Panel Tilted at the Site Latitude, Denver, Colorado

of ground reflectivity on the total yearly solar irradiance, for a panel tilted at site latitude is relatively minimal (compared to the impacts of clearness number and percent sunshine), with only a 10.2% increase when the reflectivity is increased from 20 to 80%. This is only a 0.17% increase in total yearly solar irradiance per 1% increase in ground reflectance. For most cases, the ground reflectivity would probably be contained in the 20 to 40% region which only varies the irradiance by 3.4%.

The most sensitive case for the impact of ground reflectivity would occur for a vertical panel because it would "see" the greatest amount of ground. The dependence of the daily integrated solar irradiance for a vertical panel is shown in Figure 3-28. As can be seen, the impact of ground reflectivity is much greater than the previous case (panel tilted at the site latitude). The dependence of the total yearly solar irradiance on ground reflectivity (for a vertical panel) is shown in Figure 3-29. A 12.5% increase in total yearly solar irradiance occurs if the ground reflectivity is increased from 20 to 40%. This is a 0.6% increase in total yearly irradiance for each 1% increase in ground reflectivity. This compares to the 0.17% increase per 1% increase in ground reflectivity for the panel tilted at the site latitude. Hence, for a vertical panel, the impact of ground reflectivity is much more significant. For the case where a panel is tilted at the site latitude, the range of tilt angles would be (for the U.S.) from 25 to 50 deg. Over this range, the impact of ground reflectivity would not be significant compared to the impacts of clearness number and percent sunshine.

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Panel Tilt Angle - Three cases were considered: (1) the case where the panel is tilted at the site latitude; (2) the case where the panel is horizontal; and (3) the case where the panel is vertical. The cases considered simply display the general dependence on panel tilt angle (see fig. 3-30). It is interesting to note that the horizontal panel receives as much or more solar irradiance than the optimum tilt angle during the summer months of May, June, July, and August. The vertical panel receives as much or more irradiance than the optimum tilt angle for the winter months of January, February, November, and December. Hence, the latitude tilt angle is only optimum if a yearly period is considered. If seasonal periods are considered, the optimum panel tilt will vary.

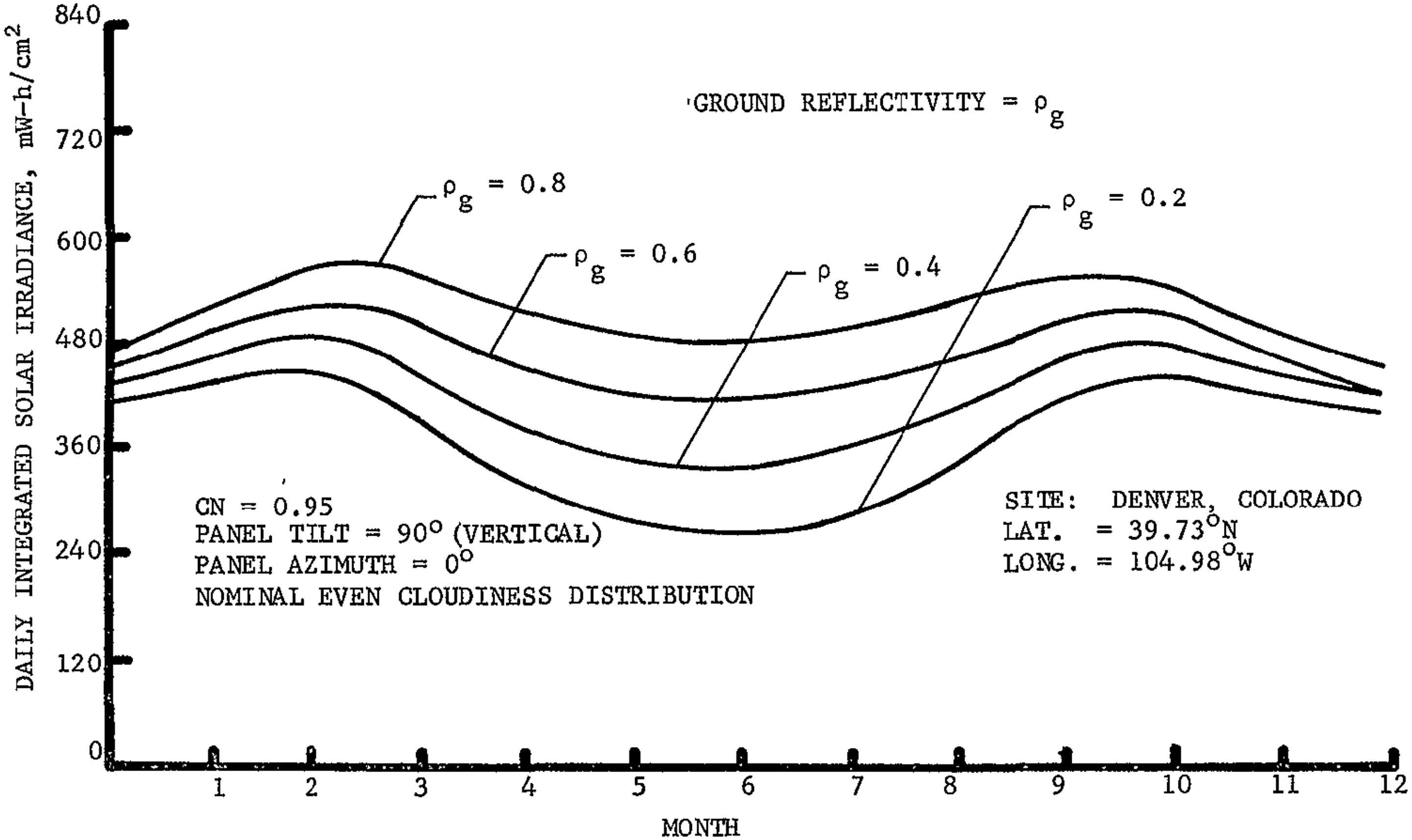


Figure 3-28 Dependence of Daily Integrated Solar Irradiance on Ground Reflectivity for a Vertical Panel

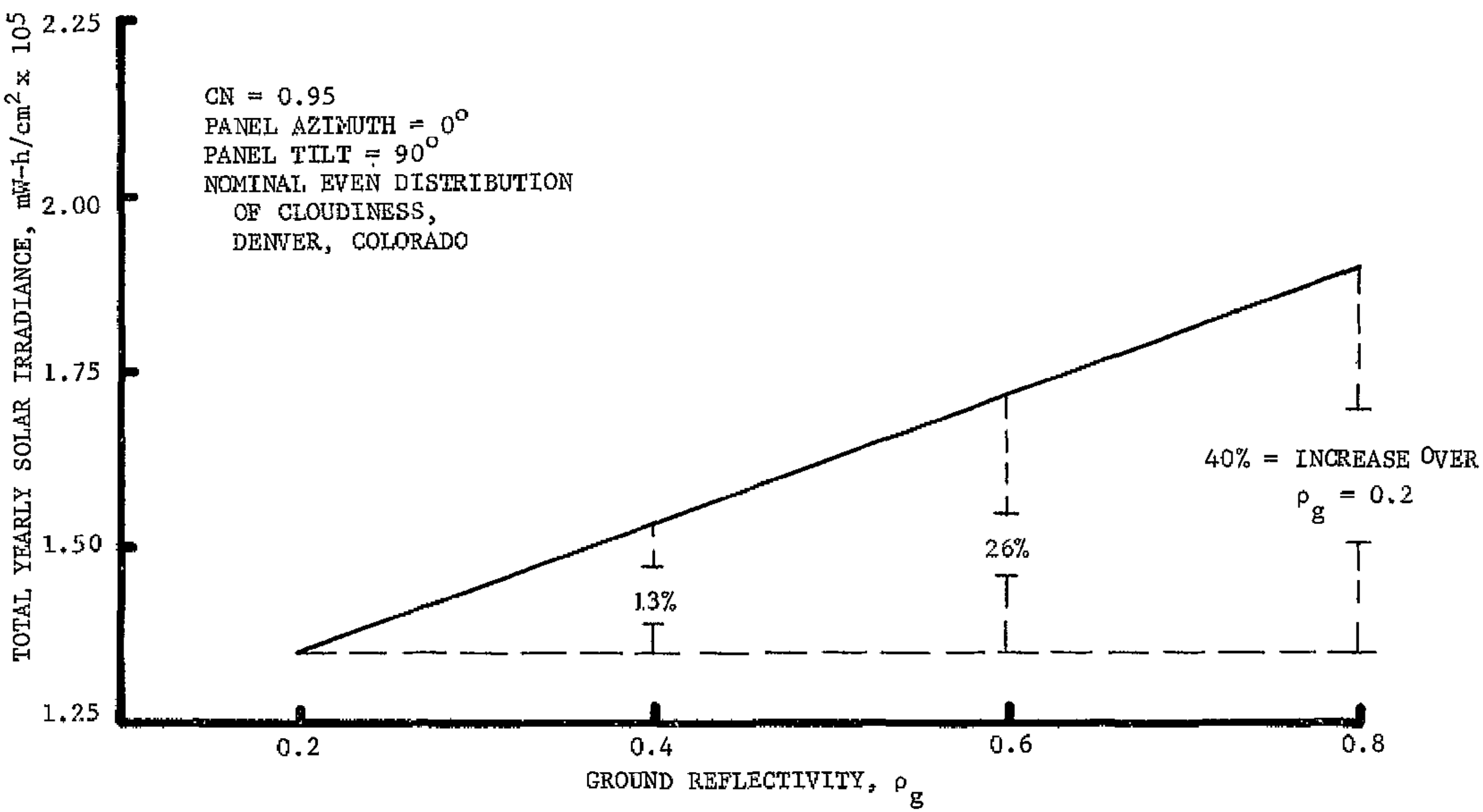


Figure 3-29 Dependence of Total Yearly Solar Irradiance on Ground Reflectivity for a Vertical Panel

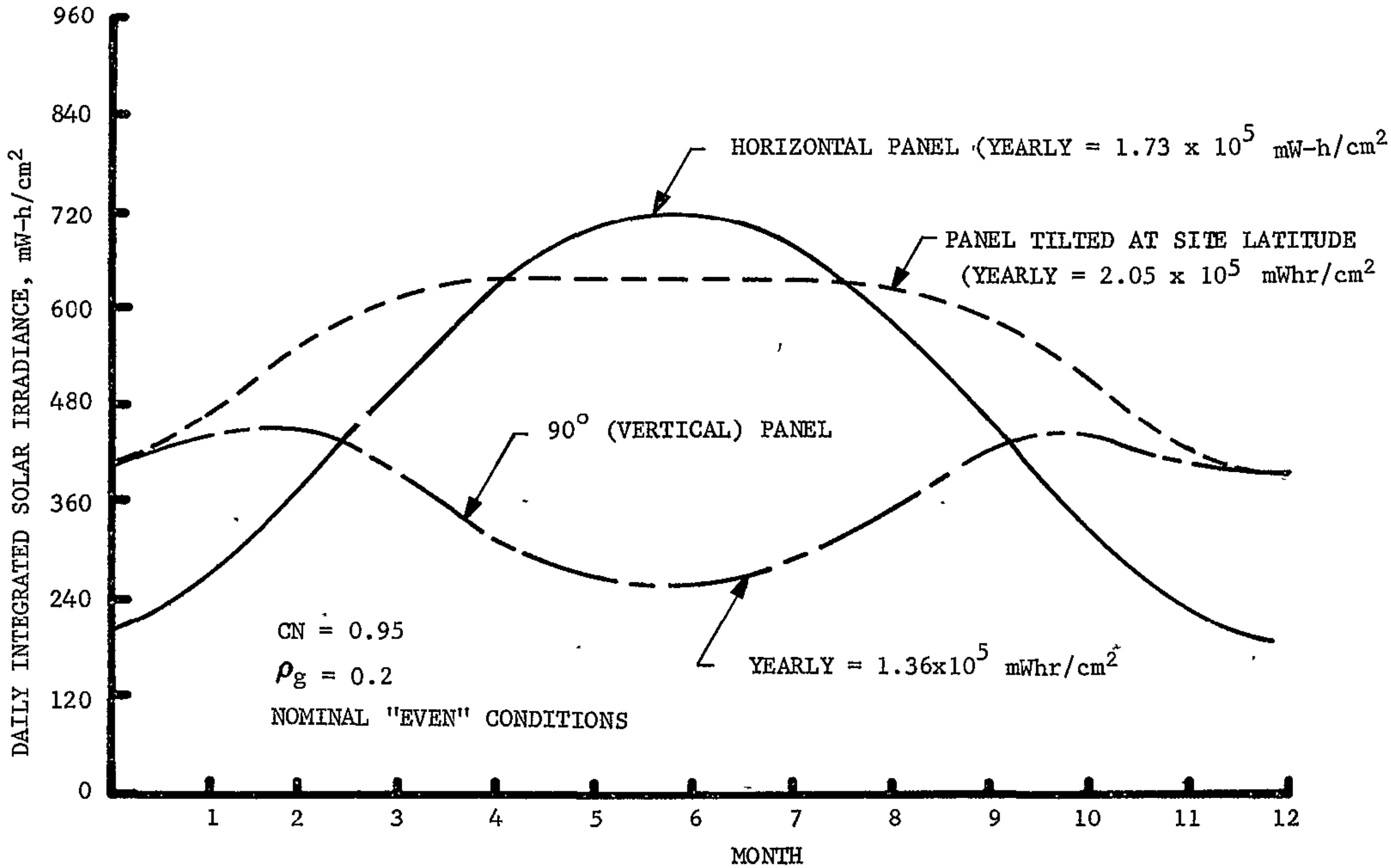


Figure 3-30 Dependence of Daily Integrated Solar Irradiance on Panel Tilt Angle, Denver, Colorado

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Panel Azimuth Angle - As mentioned previously, the daily and total yearly solar irradiance is relatively independent of panel azimuth orientation for angles of $0^{o} \pm 20^{o}$, if a day is symmetric in terms of equal amounts of irradiance being received in the morning hours and afternoon hours. This situation occurs on 100% clear days and on days when equal cloudiness occurs in the morning and afternoon. However, a site may have a characteristic cloudiness in a certain portion of the day. For example, during the summer months, Denver has predominant afternoon cloudiness due to cumulus type clouds that gradually form during the day. For this reason, SIM was given the capability of considering a "fixed" distribution of cloudiness where the cloudiness can be assigned to a given time during the day. Shown in Figure 3-31 is the daily integrated solar irradiance for an east facing panel (azimuth = -45 deg) and a west facing panel (azimuth = +45 deg). The day definition is a "fixed" cloudiness in the latter 0.4 of a day. The first 0.6 part of the day is calculated on a clear basis. As can be seen, the east facing panel receives 33% more total yearly solar irradiance than the west facing panel. The magnitude of this difference will depend upon the exact amount of time and positioning of the cloudiness.

Dependence of Daily Integrated and Total Yearly Solar Irradiance on Total Cloud Amount (TCA) on Continuous Partly Cloudy and "Worst" Case "Even" Day Definitions - As discussed previously, the two types of day definitions that use a TCA other than 0 to 10 (as used for the nominal "even" and "fixed" day definitions are the continuous partly cloudy day and the "worst" case "even" day. The continuous partly cloudy day is characterized by a continuous direct solar irradiance at a reduced level determined by the TCA. The "worst" case "even" day is similar to the nominal "even" day except where the nominal "even" day assumes a TCA = 0 (100% clear) for the clear parts of the day. The "worst" case "even" day assigns a TCA (from 1 to 9) for the clear (direct solar beam is present) parts of the day. The continuous partly cloudy TCA dependence is shown in Figure 3-32. The "worst" case "even" TCA dependence is shown in Figure 3-33. As can be seen, the two types of days have a similar dependence on the TCA. Figure 3-34 shows dependence of the total yearly solar irradiance on TCA dependence with the continuous partly cloudy day having a slightly more sensitive dependence. TCA is a major determinate of both the daily and total yearly solar irradiance, especially at the higher values of TCA.

Dependence of Daily Integrated Solar Irradiance on Type of Day Definition - Figure 3-35 shows an example of the instantaneous solar irradiance on a horizontal and continuously tracking panel for an "even" distribution of cloudiness. As can be seen, the clear and

C.2

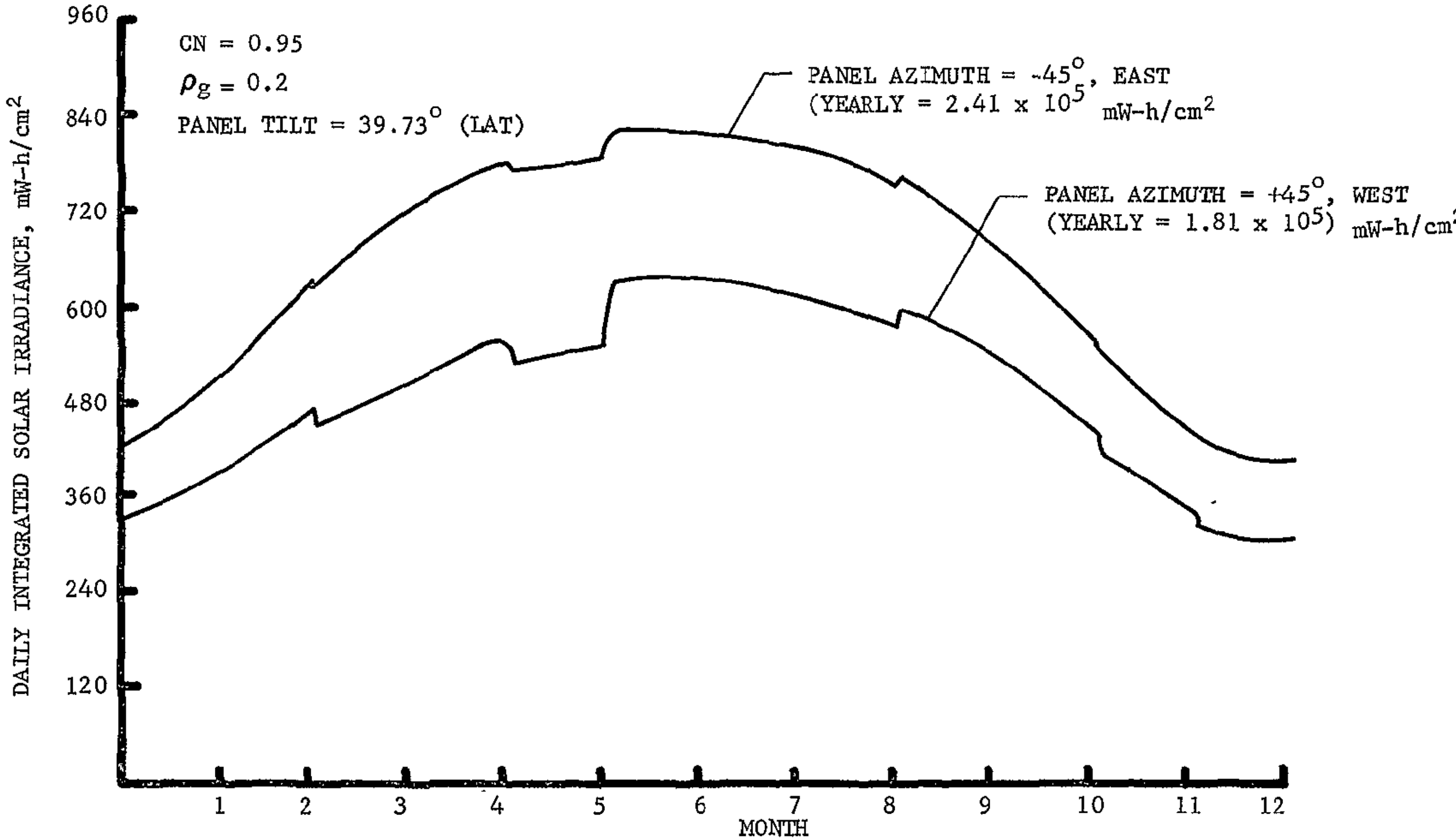


Figure 3-31 Dependence of Daily Integrated Solar Irradiance on Azimuth Orientation of Panel for a "Fixed" Afternoon Cloudiness Condition, Denver, Colorado.

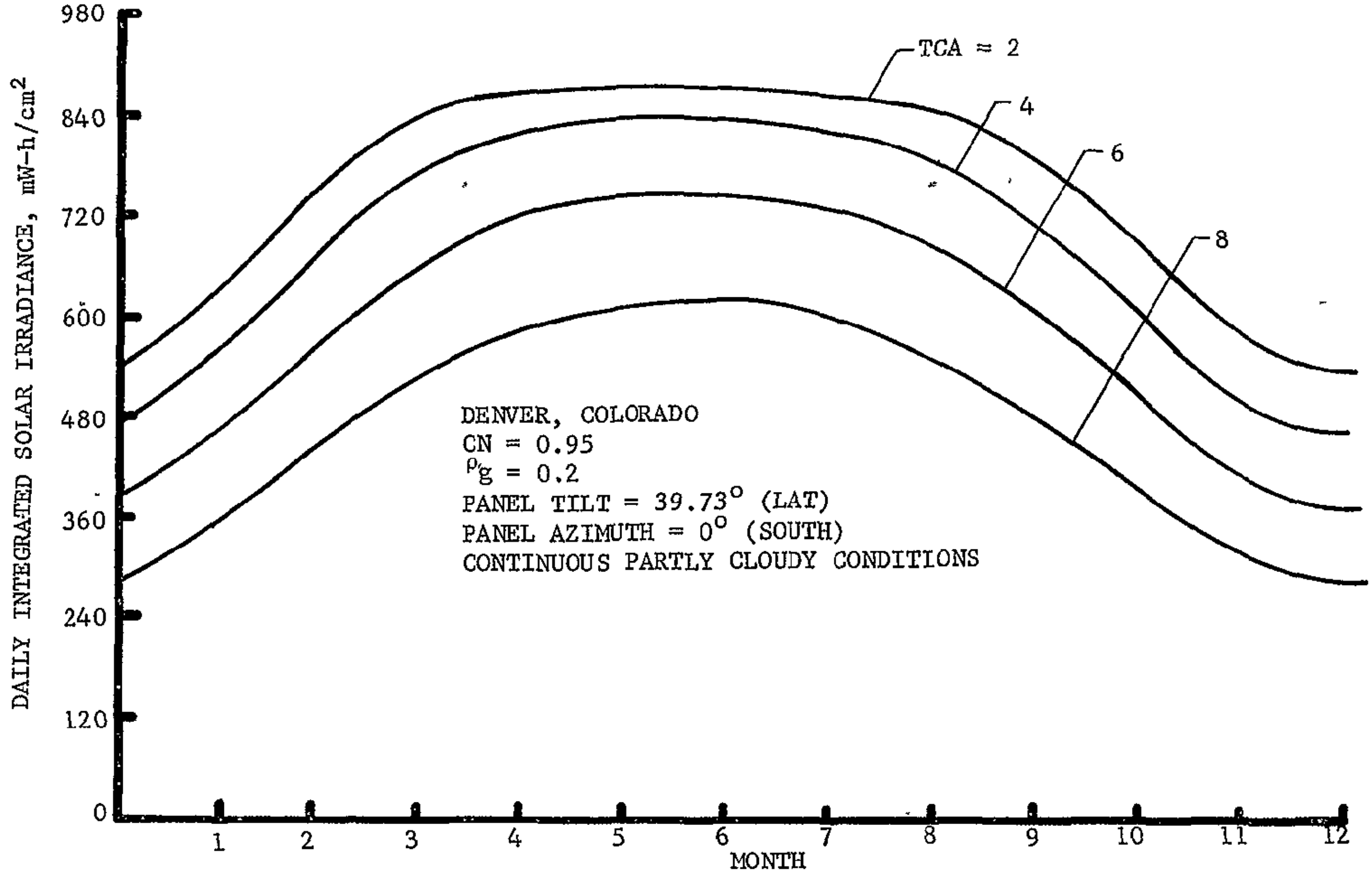


Figure 3-32 Dependence of Daily Integrated Solar Irradiance on Total Cloud Amount (TCA) for Continuous Partly Cloudy Conditions, Denver, Colorado

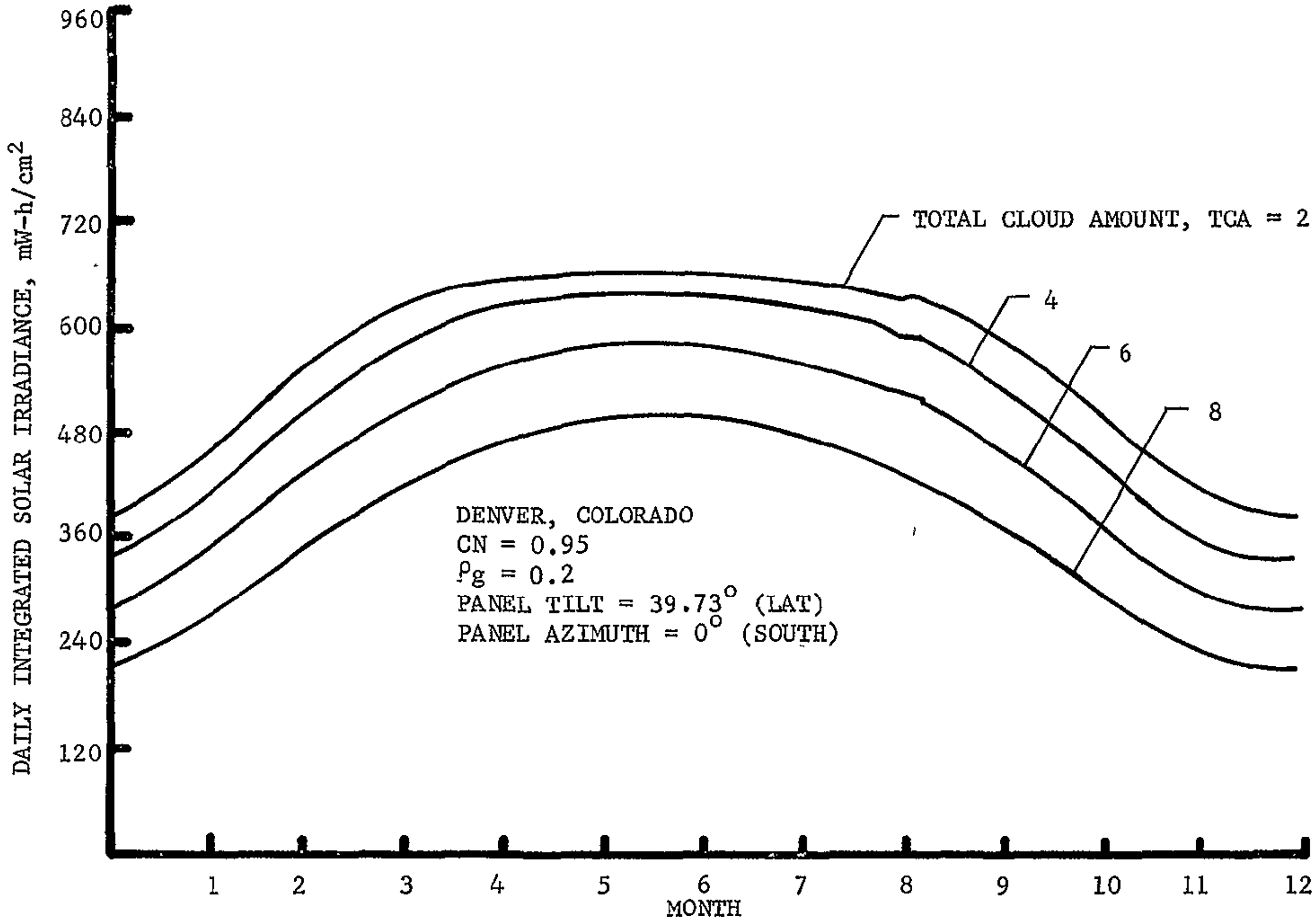


Figure 3-33 Dependence of Daily Integrated Solar Irradiance on Total Cloud Amount (TCA) for "Worst" Case "Even" Cloudiness Distribution

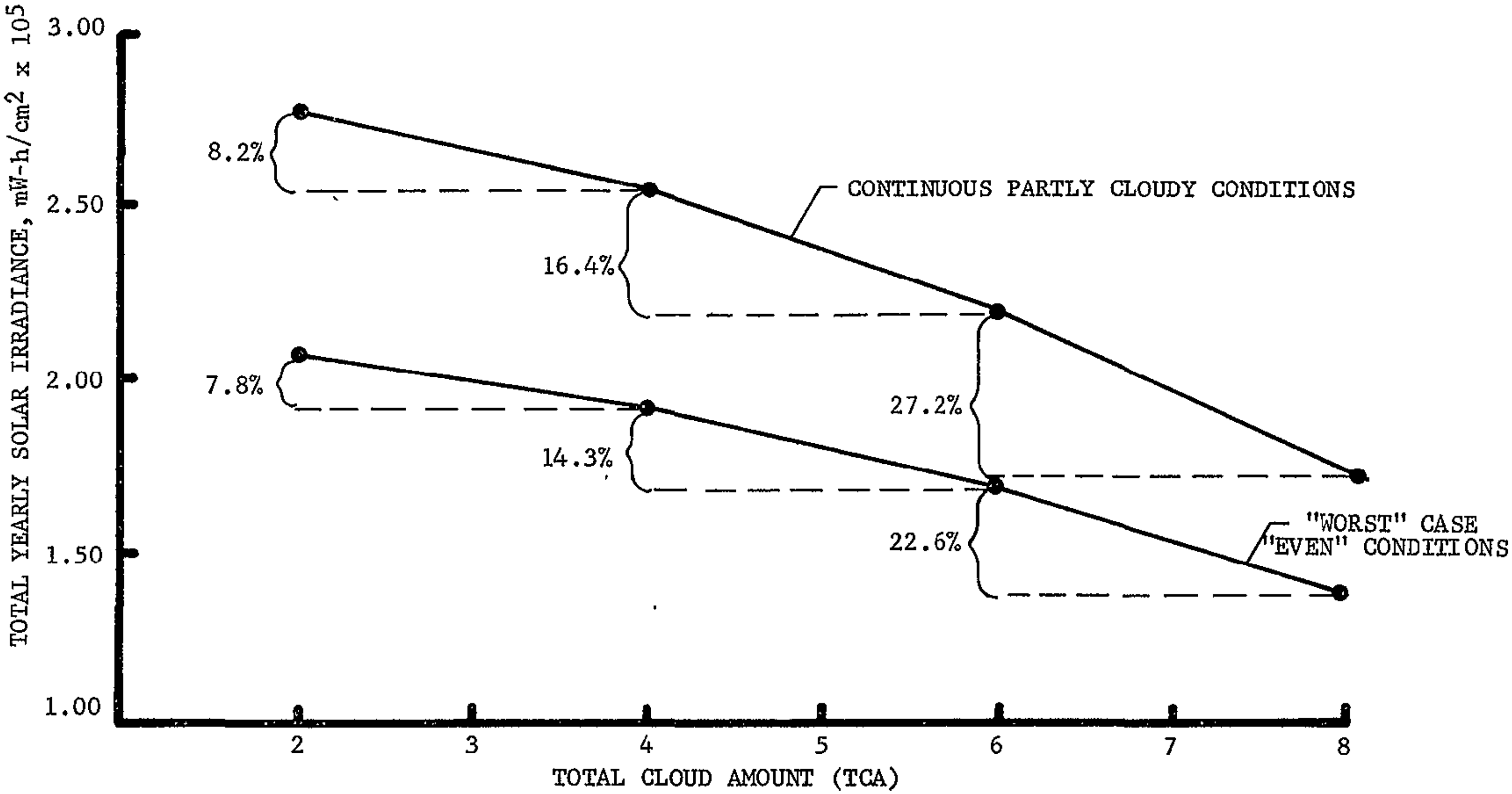


Figure 3-34 Dependence of Total Yearly Solar Irradiance on Total Cloud Amount for Continuous Partly Cloudy and "Worst" Case "Even" Distribution

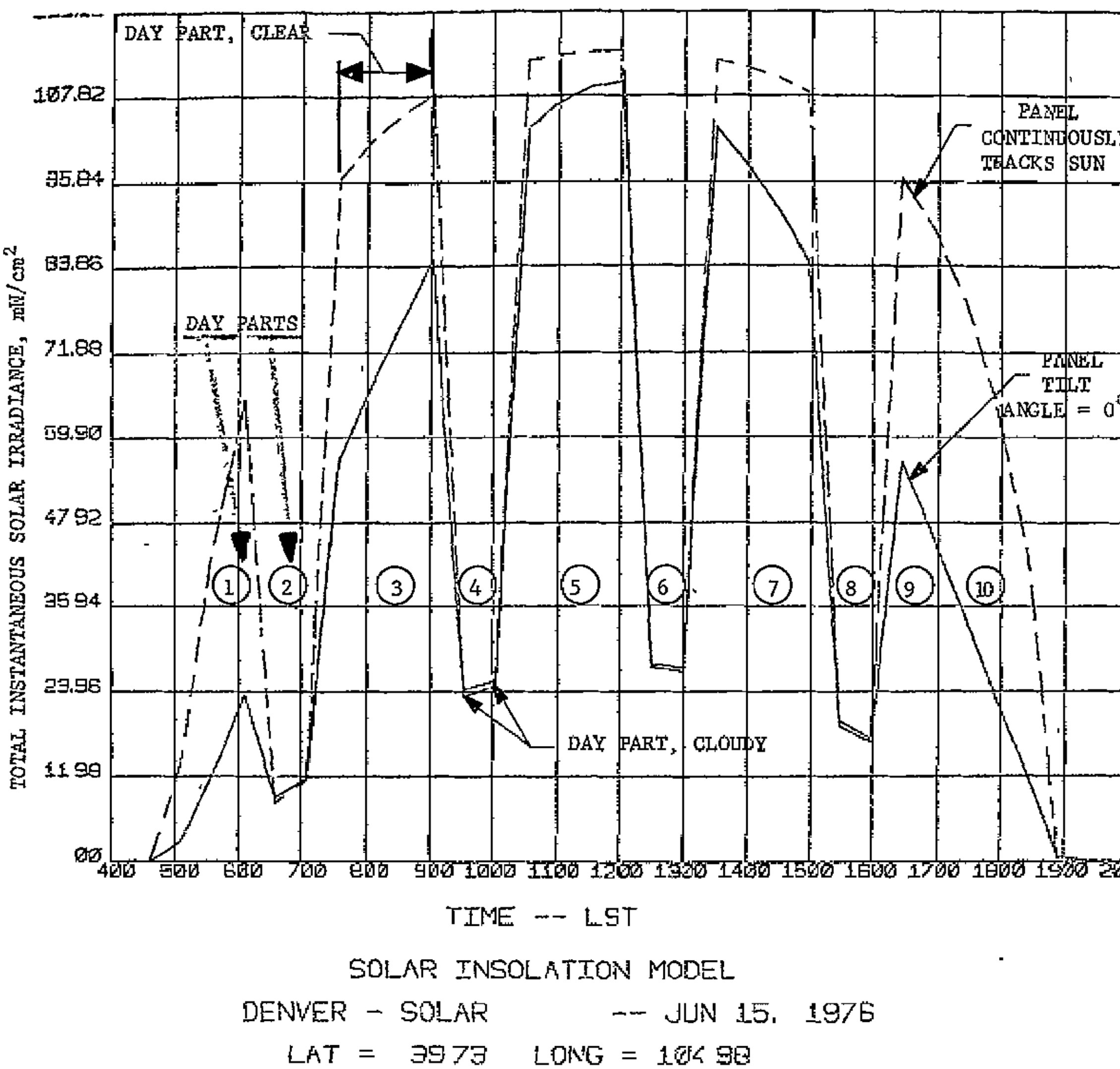


Figure 3-35 Example of a Nominal "Even" Distribution of Cloudiness, Denver, Colorado, Percent Sunshine = 69%, CN = 0.95

cloudy parts of the day are evenly distributed throughout the day. For a nominal "even" day, the clear parts of the day are assigned a TCA = 0 (100% clear) and the cloudiness portion is assigned a TCA = 10. For the "worst" case "even" day, the "clear" parts are assigned a TCA from 1 to 9. This reduces the solar irradiance for the "clear" parts. An example of a "fixed" distribution of cloudiness is shown in Figure 3-36. As can be seen, the clear part of the day is "fixed" during the first portion of the day and the cloudiness portion of the day is "fixed" during the latter portion of the day. A nominal "fixed" day is assigned a TCA = 0 during the clear portion and a TCA = 10 during the cloudy portion. A "worst" case "fixed" day is assigned a TCA from 1 to 9 for the "clear" portion of the day.

Figure 3-37 for Denver, Colorado shows the impacts of the various types of day definitions. There are two apparent characteristics listed as follows.

(1) The "fixed" type of days give higher values of solar irradiance than the "even" type days.

(2) The "fixed" type of days have step type appearances from month to month; whereas, the "even" type days give smooth variations from month to month.

The "fixed" type of day gives higher values of solar irradiance because it allows the more intense, noon, values of solar irradiance to be calculated on a clear basis. Whereas, the "even" type days distribute the cloudy portions over all levels (including the more intense noon-values) of solar irradiance. This is true for the cases shown in Figure 3-37 because the percent sunshine is 60% or greater. This allows the first 60% of the day to be calculated on a clear basis. This 60% includes the noon levels of solar irradiance. The calculation for a given site was made on a "fixed" basis for percent sunshine of 50% and less, the difference between the two day definitions would gradually decrease with decreasing percent sunshine.

The "fixed" cloudiness days have step appearances because the "fixed" clearness portion varies with the percent sunshine from month to month. For months having higher values of percent sunshine, this allows a greater portion of the more intense noon day portions to be calculated on a clear basis. This then results in higher values of daily integrated solar irradiance.

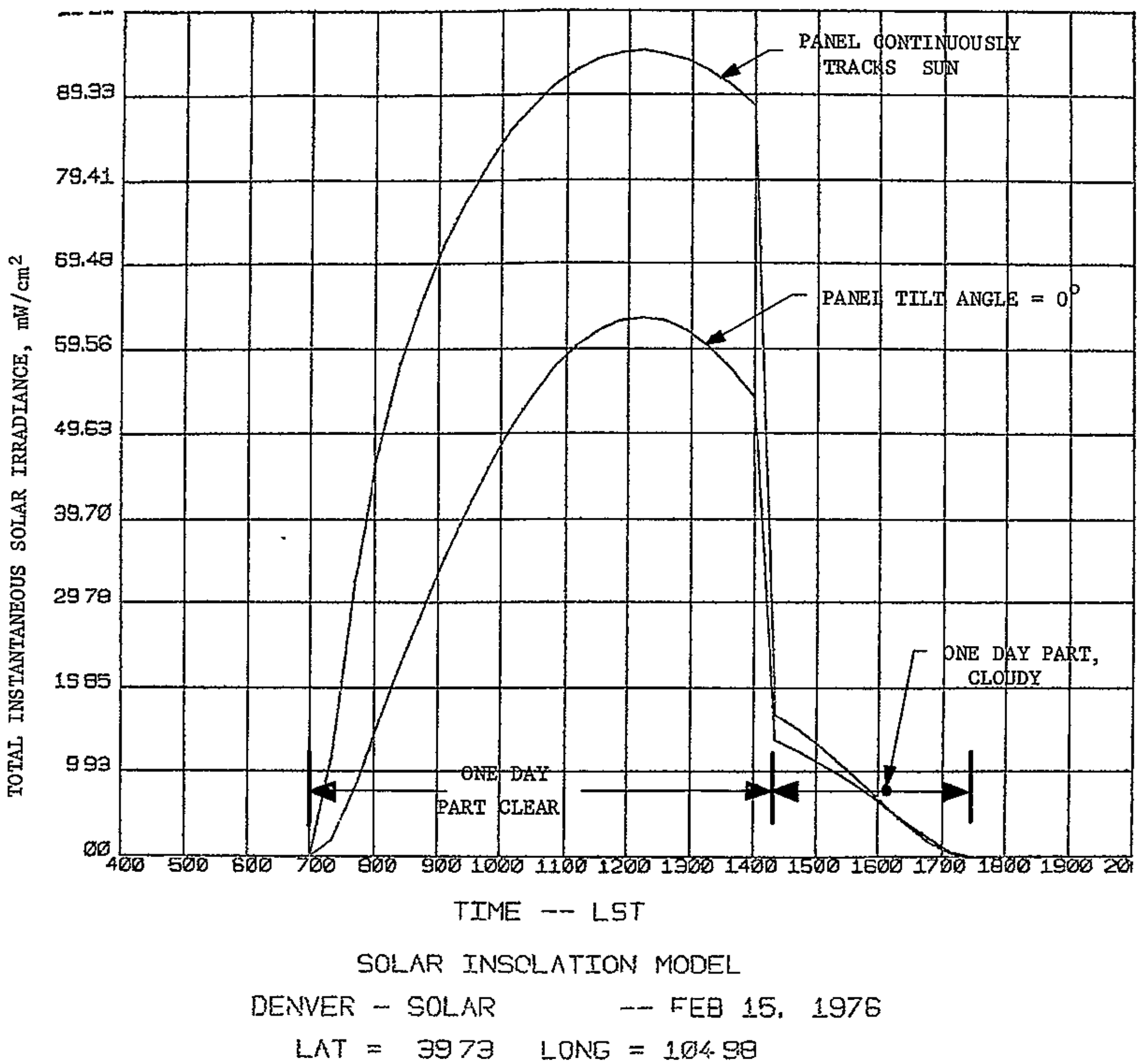


Figure 3-36 Example of a Nominal Fixed Distribution of Cloudiness, Denver, Colorado, Percent Sunshine = 69%, CN = 0.95

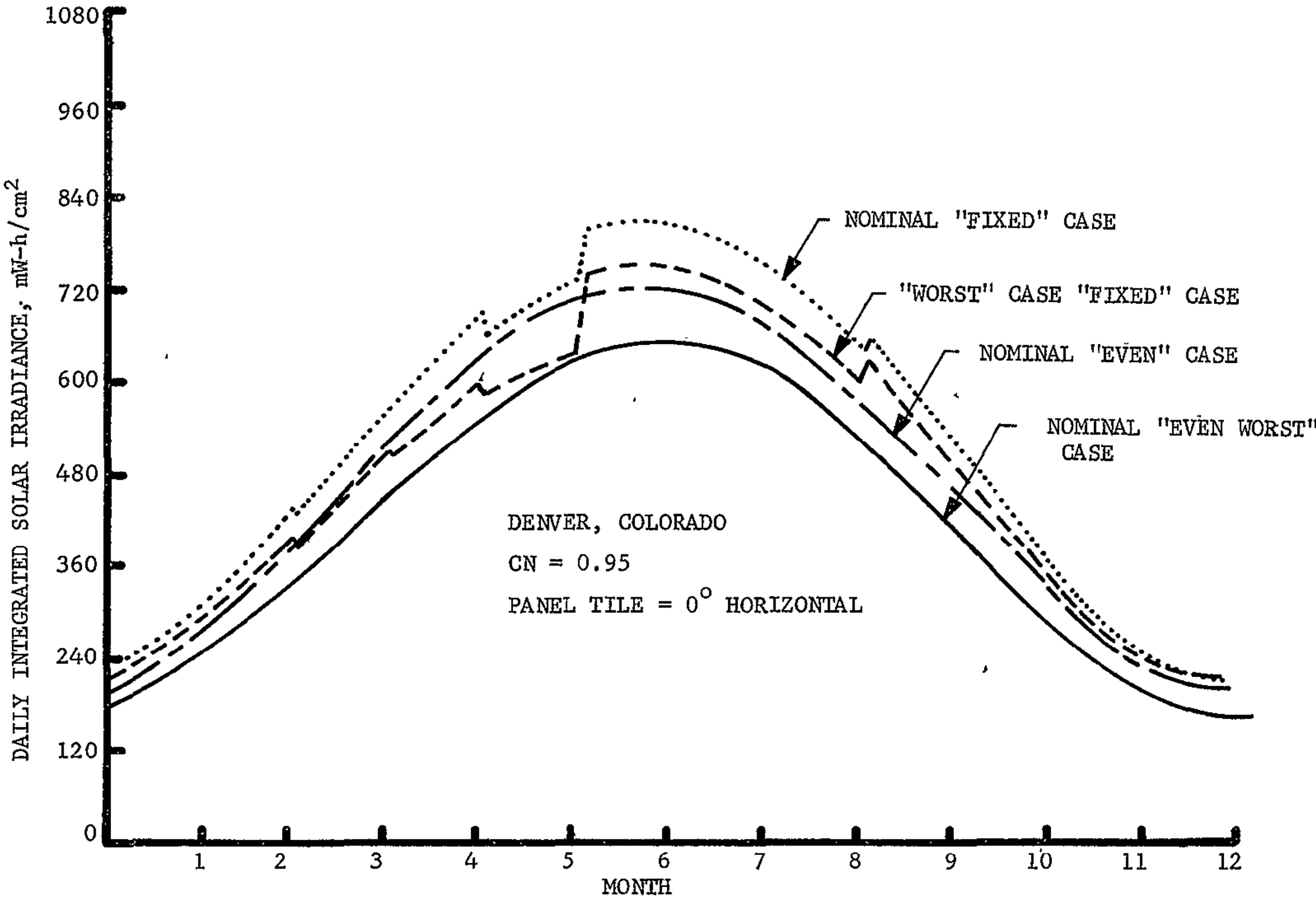


Figure 3-37 Dependence of Daily Integrated Solar Irradiance on Type of Day Definition

Dependence of Total Yearly Solar Irradiance on Panel Tilt Angle and Yearly Distribution of Percent Sunshine - The results of the sensitivity analyses for Cleveland and Denver are shown in Figures 3-38 and 3-39, respectively. In each figure, the total yearly solar irradiance is shown as a function of panel tilt angle. For Cleveland the panel tilt angle resulting in the maximum yearly solar irradiance is equal to the latitude minus 10^{o}. For Denver the optimum panel tilt angle is equal to the latitude minus 5^{o}. It can be seen for each site that a wide range of panel tilt angles can be considered with only a 1% decrease in yearly solar irradiance. For Cleveland a range of panel tilt angles from latitude minus 21^{o} (or 20.4^{o}) to latitude minus 2^{o} (or 39.4^{o}) will result in yearly irradiances only 1% or less lower than the maximum (at 31.4^{o}). For Denver this range extends from latitude minus 14^{o} to latitude $+4^{o}$. The fact that the Cleveland maximum occurs at a latitude minus 10^{o} and the maximum for Denver occurs at latitude minus 5^{o} can be attributed to the yearly distribution of percent sunshine. As shown in Figure 3-40, the maximum difference in daily integrated solar irradiance for Cleveland occurs during the summer months. At this time the maximum daily irradiance is obtained with the lower panel tilt angles. This maximum difference corresponds to the higher percent sunshine during the summer months. A minimum difference occurs during the winter months when the percent sunshine is the lowest. As shown in Figure 3-41, Denver (due to its uniform distribution of sunshine) exhibits more uniform differences throughout the year. Therefore, Cleveland's yearly maximum occurs toward lower panel tilt angles than that of Denver.

The SIM sensitivity analysis resulted in the following conclusions.

(1) Using a nominal "even" distribution of cloudiness, recommended values of clearness numbers, and percent sunshine from the *National Climatic Atlas*, SIM perdictions of daily integrated, horizontal, solar irradiance agree closely with historical data (i.e., with a mean monthly relative error ranging from 2.8 to 10.9%).

(2) For day definitions involving 100% clear conditions (including the 100% clear, nominal "even" and nominal "fixed" day definitions), the percent sunshine is a major determinate of the daily and total yearly solar irradiance. There exists a nearly linear relationship between clearness number and a 10% increase in total yearly solar irradiance. The site clearness number determines the general level of solar irradiance. Close agreement with historical data could be obtained by simple adjustments of the site sunshine number.

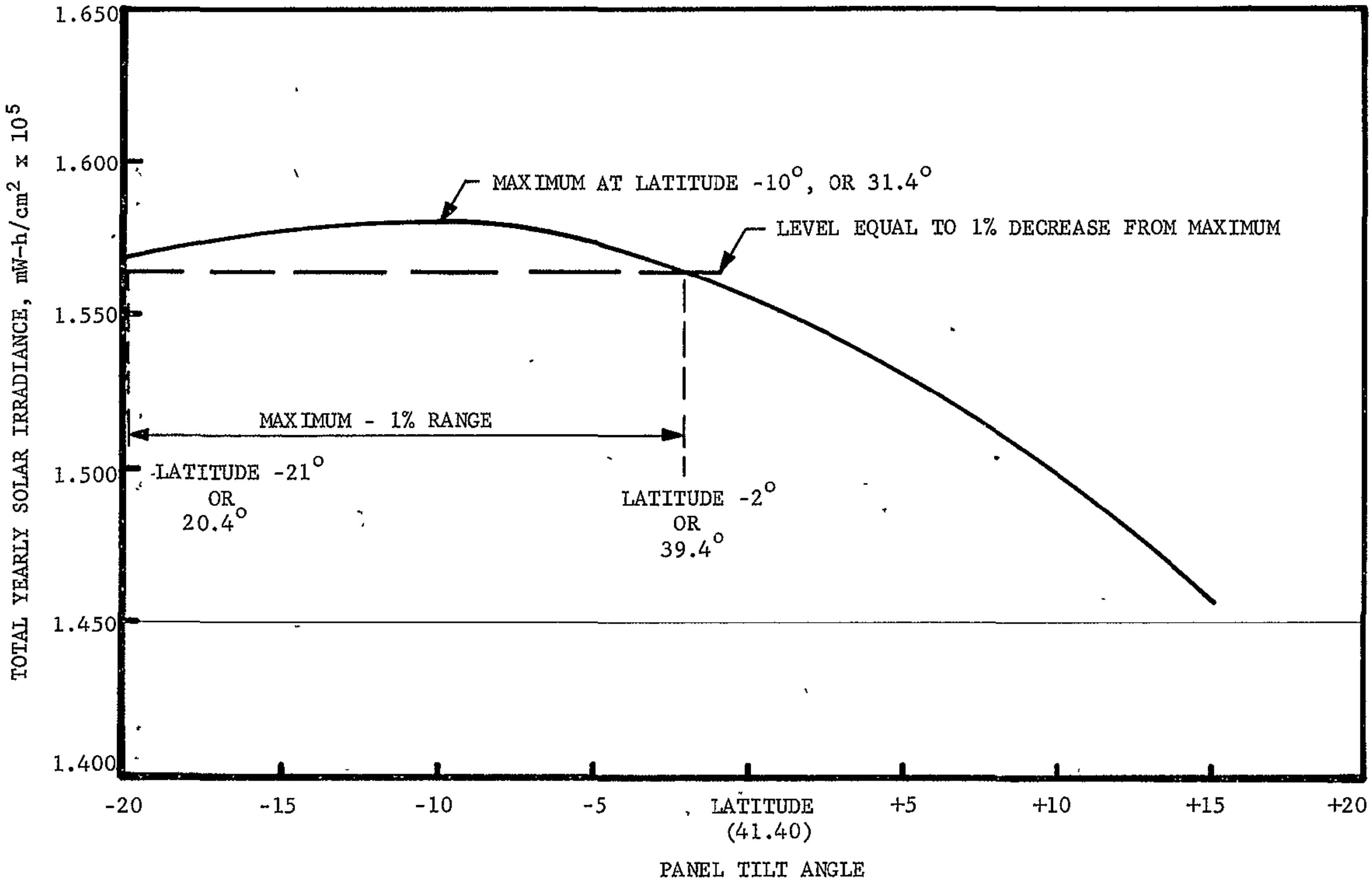


Figure 3-38 Dependence of Total Yearly Solar Irradiance on Panel Tilt Angle for Cleveland, Ohio

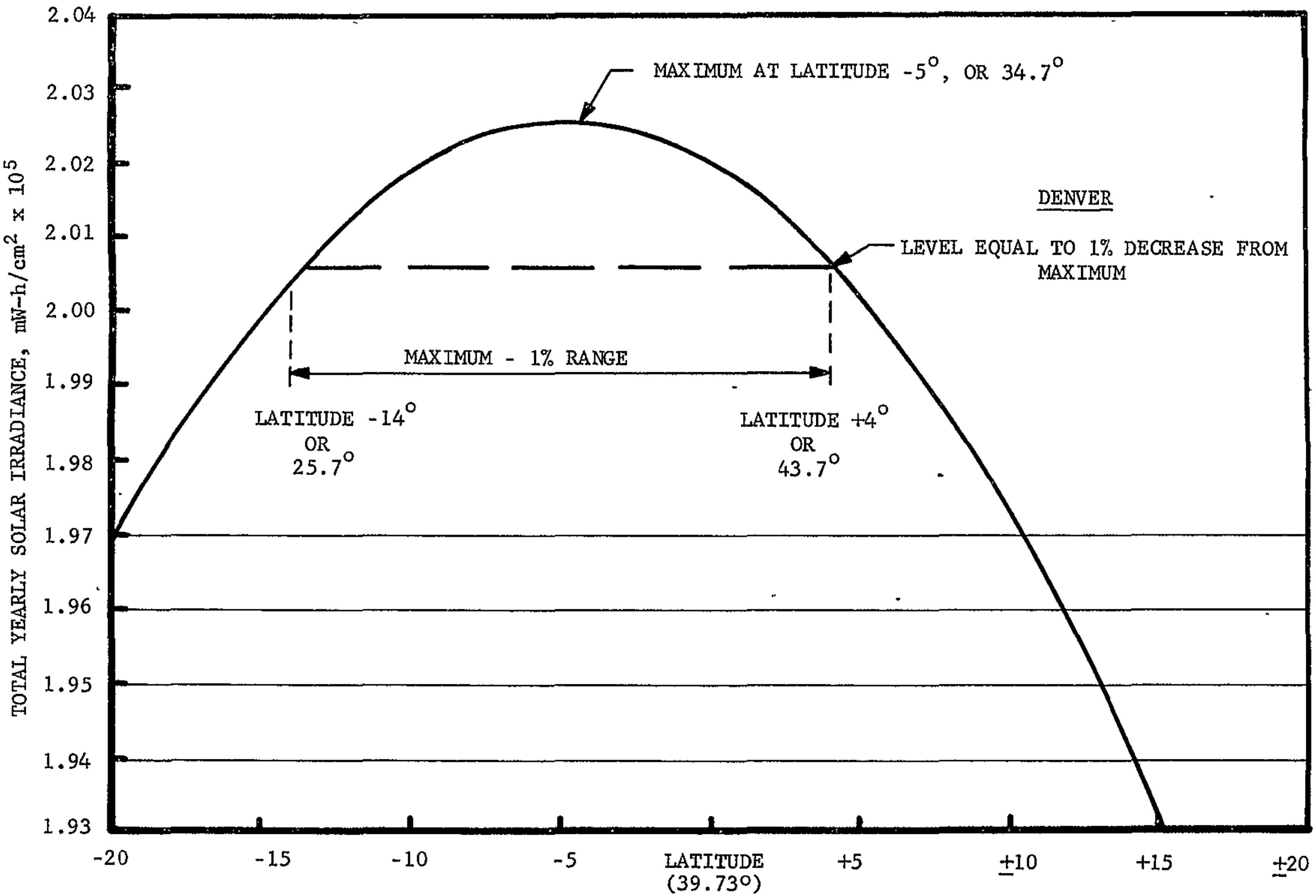


Figure 3-39 Dependence of Total Yearly Solar Irradiance on Panel Tilt Angle for Denver, Colorado

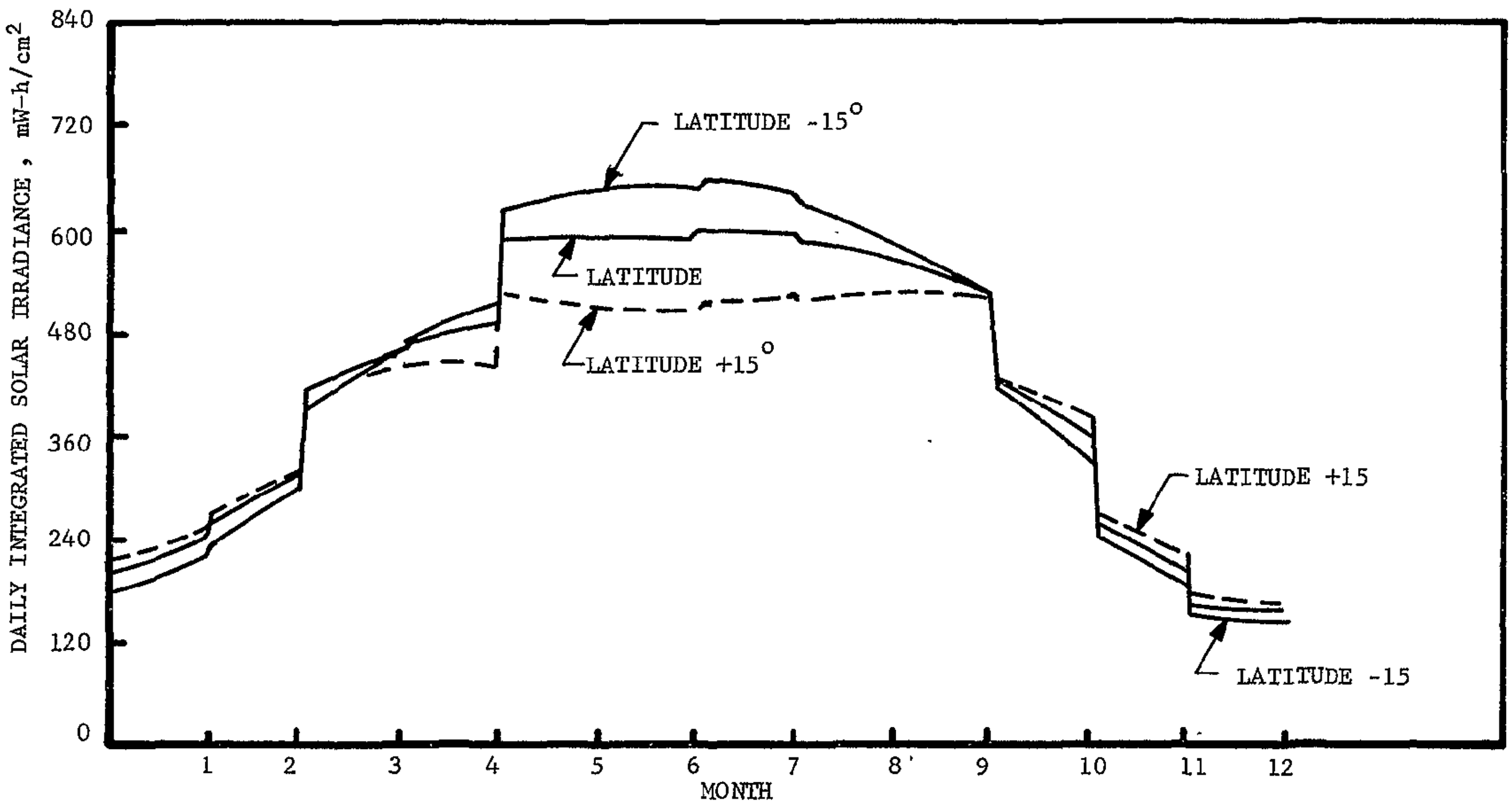


Figure 3-40 Dependence of Daily Integrated Solar Irradiance for Various Panel Tilt Angles for Cleveland, Ohio

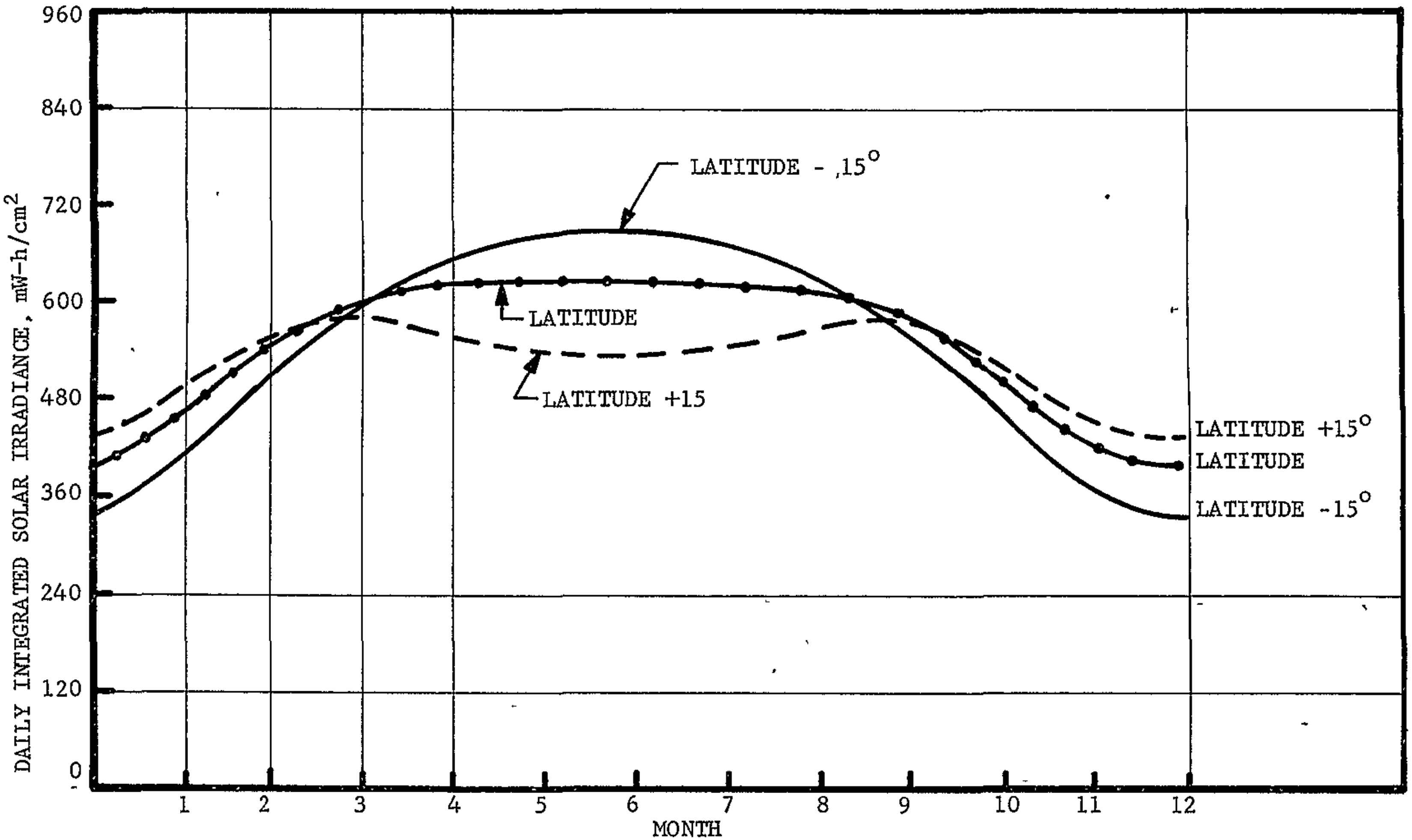


Figure 3-41 Dependence of Daily Integrated Solar Irradiance for Various Panel Tilt Angles for Denver, Colorado

(3) For all types of days (except the 100% clear and continuous partly cloudy day) the clearness number is a major determinate of daily integrated and total yearly solar irradiance. At 1% increase in percent sunshine, in the region of 20 to 40% sunshine will produce a 1.85% increase in total yearly solar irradiance. In the region of 60 to 80% sunshine, a 1% increase in percent sunshine will produce a 2.5% increase in total yearly solar irradiance.

(4) The ground reflectivity is a relatively minor determinate of daily integrated and total yearly solar irradiance. The impact of ground reflectivity depends on the panel tilt angle. For a panel tilted at the site latitude for Denver, Colorado, an increase of ground reflectivity from 20 to 80% resulted in an increase of 10.2% in total yearly solar irradiance; for a vertical panel, an increase of ground reflectivity from 20 to 80% resulted in an increase of 39.7% in total yearly solar irradiance.

(5) In general, the panel tilt angle is a major determinate of daily integrated and total yearly solar irradiance. For Denver, Colorado, a panel tilted at the site latitude received a yearly solar irradiance of 2.05×10^5 mW-h (milliwatt-hour)/cm^2, a horizontal panel received 1.73×10^5 mW-h/cm^2, a vertical panel received 1.36×10^5 mW-h/cm^2. However, on a monthly basis, the vertical panel received more solar irradiance than the panel tilted at the site latitude for the winter months of November, December, January, and February. The horizontal panel received more solar irradiance than the latitude panel for the summer months of May, June, July, and August.

(6) If "fixed" cloudiness conditions are considered, the panel azimuth angle can be a major determinate of daily and total solar irradiance. For a "fixed" afternoon cloudiness condition with 0.6 of the first day part being clear and the remaining 0.4 being cloudy, a panel facing 45° east of south received 33% more yearly solar irradiance than a panel facing 45° west of south.

(7) For continuous partly cloudy and "worst" case "even" cloudiness distribution day definitions, the site's total cloud amount is a major determinate of daily and total yearly solar irradiance. For a "worst" case "even" distribution of cloudiness day definition, an increase in total cloud amount from six tenths to eight tenths resulted in a decrease of 23% for the total yearly solar irradiance.

(8) The type of day definition is a major determinate of the daily and yearly solar irradiance.

(9) The yearly distribution of percent sunshine will impact the optimum panel tilt angle for receiving a maximum yearly solar irradiance. For Cleveland the optimum panel tilt angle is 31.4° (latitude -10°). However, a range of panel tilt angles from 20.4 to 39.4° can be considered with only a 1% loss in yearly solar irradiance. For Denver, the optimum panel tilt angle for receiving the maximum yearly solar irradiance is 34.7° (latitude -5°). A range of panel tilt angles can be considered from 25.7 to 43.7° with only a 1% loss in yearly solar irradiance. The difference between the optimum panel tilt angle for Cleveland (latitude minus 10°) compared to Denver (latitude minus 5°) is attributed to the difference in the yearly distribution of percent sunshine.

3.6.3 Solar Array

The solar array was assumed to consist of 1.22 x 1.22m (4 x 4 ft) subarrays as specified in JPL RFP BQ66829-16, 15 December 1975, in accordance with the requirements of this contract. Table 3-19 summarizes the solar array design guidelines based on the requirements of JPL Request for Proposal No. BQ66829-16.* Using this information, the numer of cells needed for the module was calculated and in turn the subarray characteristics were determined. The module electrical output was derived using the NASA LeRC supplied solar cell characteristics. The voltage range stipulated for the module requires the use of 40 to 44 series Solarex 2.25-inch diameter cells (for a temperature of 60°C and an insolation level of 100 mW/cm^2). The module voltage-temperature profile allows for determination of the subarray (and ultimately the solar array) voltage-temperature characteristics.

The range module voltage (at peak power) as a function of temperature is shown in Figure 3-42. For purposes of analysis, the 44-cell module was chosen as the basic component for subarray construction.

The criteria for subarray design are:

(1) Ease of acquiring system operating voltage;

(2) Provide flexibility of array output voltage;

*JPL Request for Proposal No. BQ-6-6829-16, "Large Scale Production Task - Low Cost Silicon Solar Array Project", 15 December 1975.

Table 3-19 Solar Array Design Guidelines

Parameter	Value
Subarray size*	1.22 x 1.22-m (4 ft x 4 ft)
Minimum Peak Output Power of Subarray	70 watts @ 60°C and 100 mW/cm^2
Subarray Output Voltage	15.8 to 17 volts @ 60°C

*Solar cell modules to be positioned in the subarray within a 46-in by 46-in square envelope (including module electrical interconnection and module structural attachment).

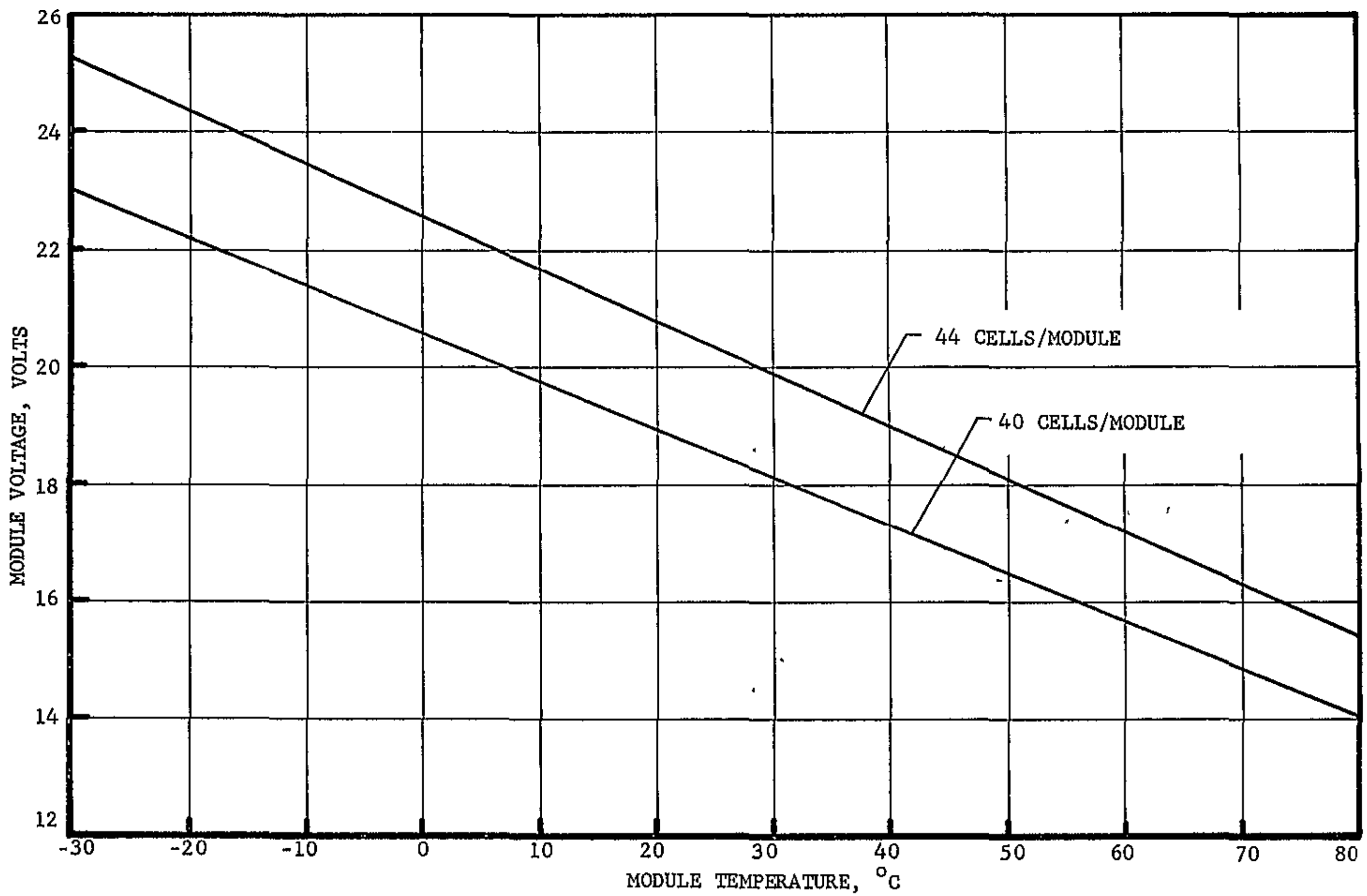


Figure 3-42 Solar Array Module Voltage at Peak Power Versus Temperature

(3) Total number of cells must fit into subarray structure accounting for adequate packing factor;

(4) Power output per subarray must meet or exceed 70W at $60^{\circ}C$ and 100 mW/cm^2 insolation. The subarray baseline design selected to satisfy these criteria is summarized in Table 3-20. Note that the power output as derived from the cell characteristics exceeds the minimum requirement.

Based on the subarray design, the baseline solar array consisted of five subarrays in series (to deliver adequate voltage) and 18 subarrays in parallel. The solar array baseline characteristics are shown in Table 3-21. A functional block diagram of the subarray, indicating the relationship between the cells and modules, is shown in Figure 3-43.

Table 3-20 Subarray Baseline Characteristics

Number of Series Modules	2
Number of Parallel Modules	4
Subarray Size	1.2m x 1.2m (4 ft x 4 ft)
Total Number of Cells	352
Power Output (at 60°C and Intensity of 100 mW/cm^2)	90 watts
Packing Factor (based on 46" x 46" envelope)	66% (Note for Round Cells, 78.5% is the Maximum Packing Factor).
Peak Power Point Voltage at 60°C and 100 mW/cm^2	34 volts

Table 3-21 Solar Array Baseline Characteristics

Number of Cells	31680
Total Cell Area	81.26 m^2
Array Area	133.8 m^2
Packing Factor	60.7%
Array Output Power at: 28°C and Intensity = 100 mW/cm^2	9183 watts
Array Output Power at: 60°C and Intensity = 100 mW/cm^2	8161.8 watts

The peak power point voltage of the baseline array is shown in Figure 3-44. This voltage does not fall below 160-Vdc up to an array temperature of 70°C. Thus, the design adequately provides charging of a 6-cell battery with a 144-Vdc charge voltage limit under normal operating conditions.

Figure 3-45 shows the estimated I-V characteristics of the baseline array at several temperatures. The sensitivity of the solar array output power to the solar irradiance is illustrated in Figure 3-46. Similarly, the temperature effect on the power output is shown parametrically in Figure 3-47.

3.6.4 Battery

The main criterion for the battery discharge voltage range is that it must be compatible with the inverter input voltage limits.

As shown in Table 3-22, a large majority of off-the-shelf inverters have an input voltage range of 105 to 140 volts. The

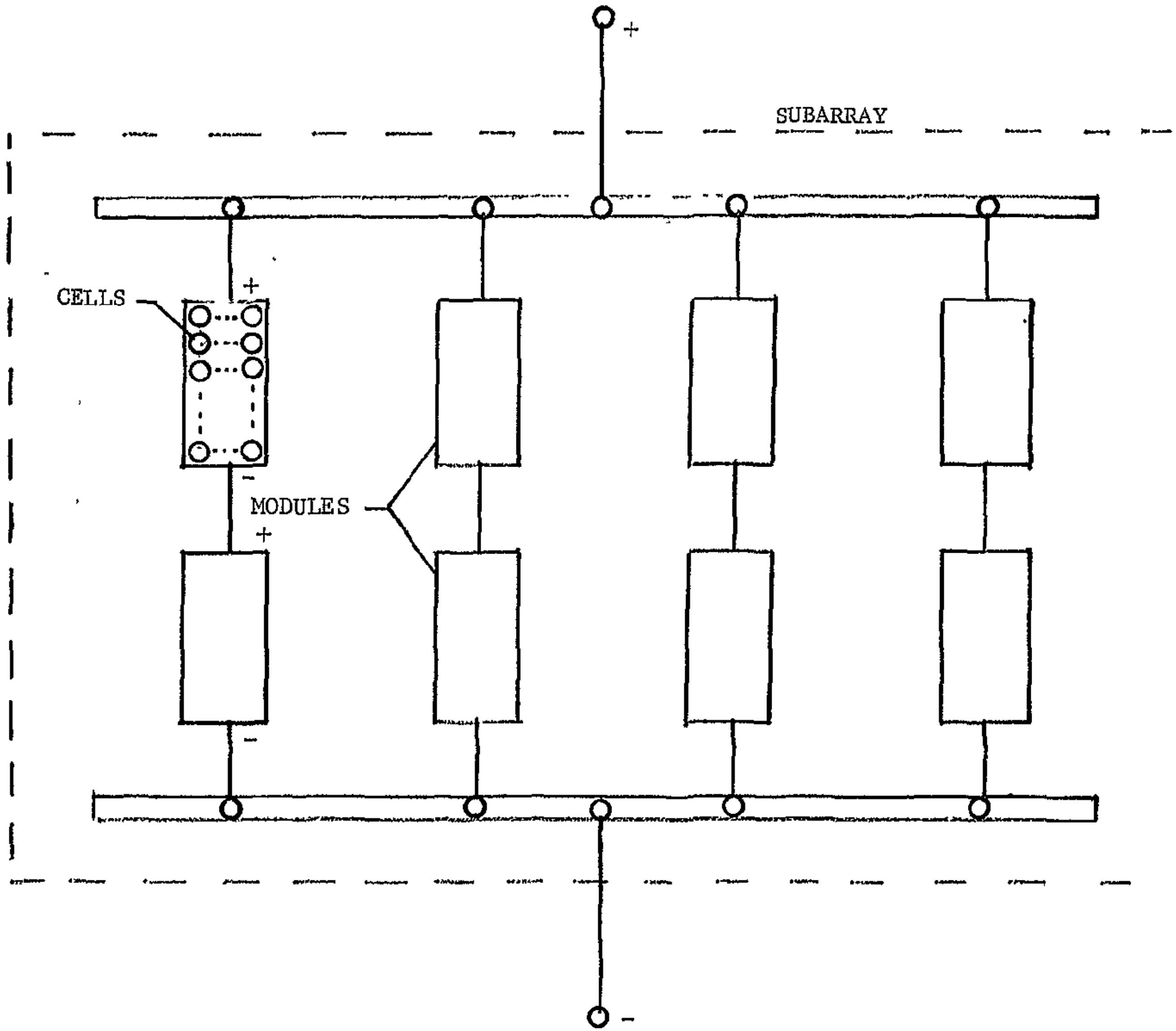


Figure 3-43 Baseline Subarray Block Diagram

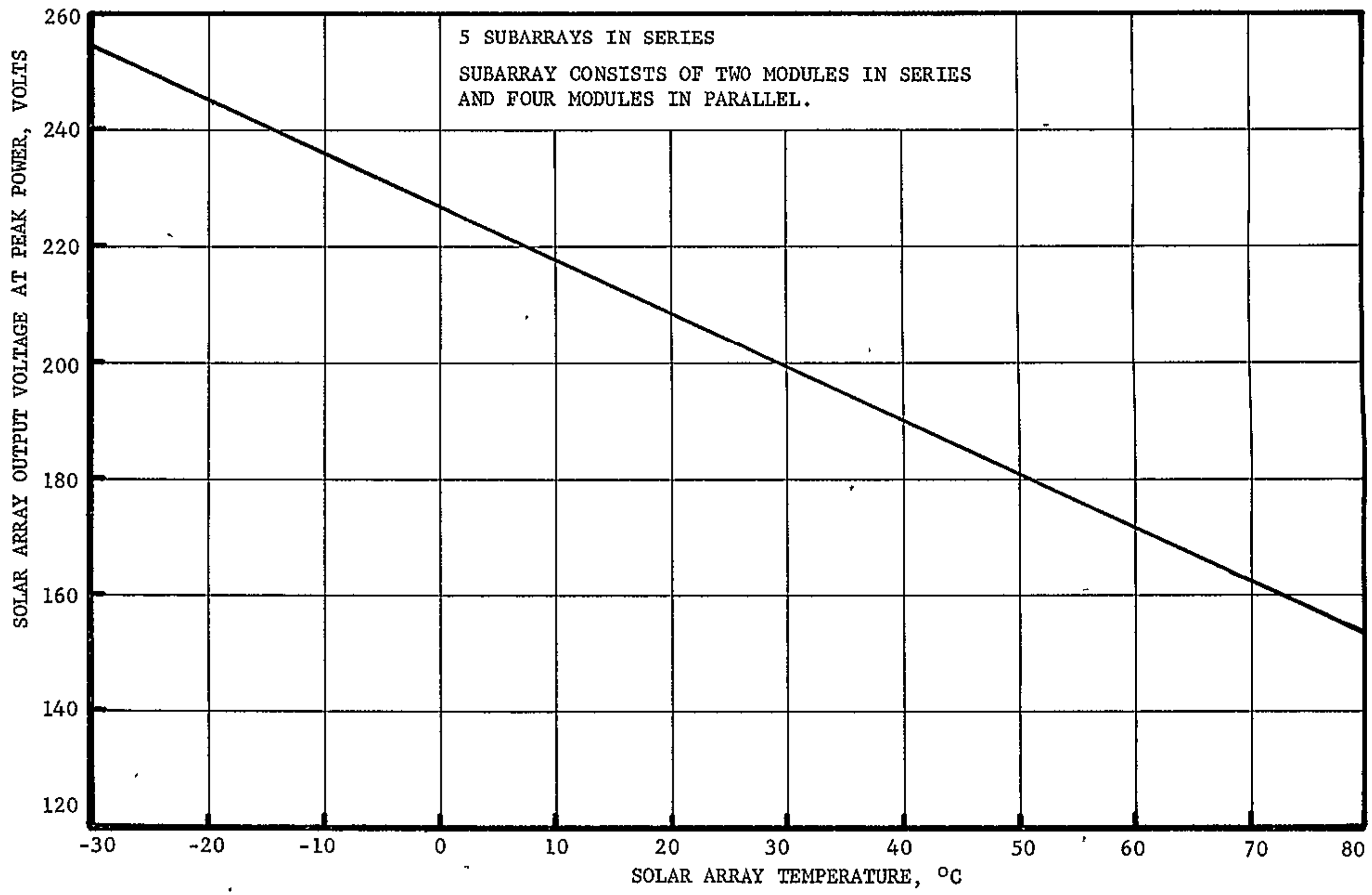


Figure 3-44 Array Output Voltage at Peak Power Versus Temperature

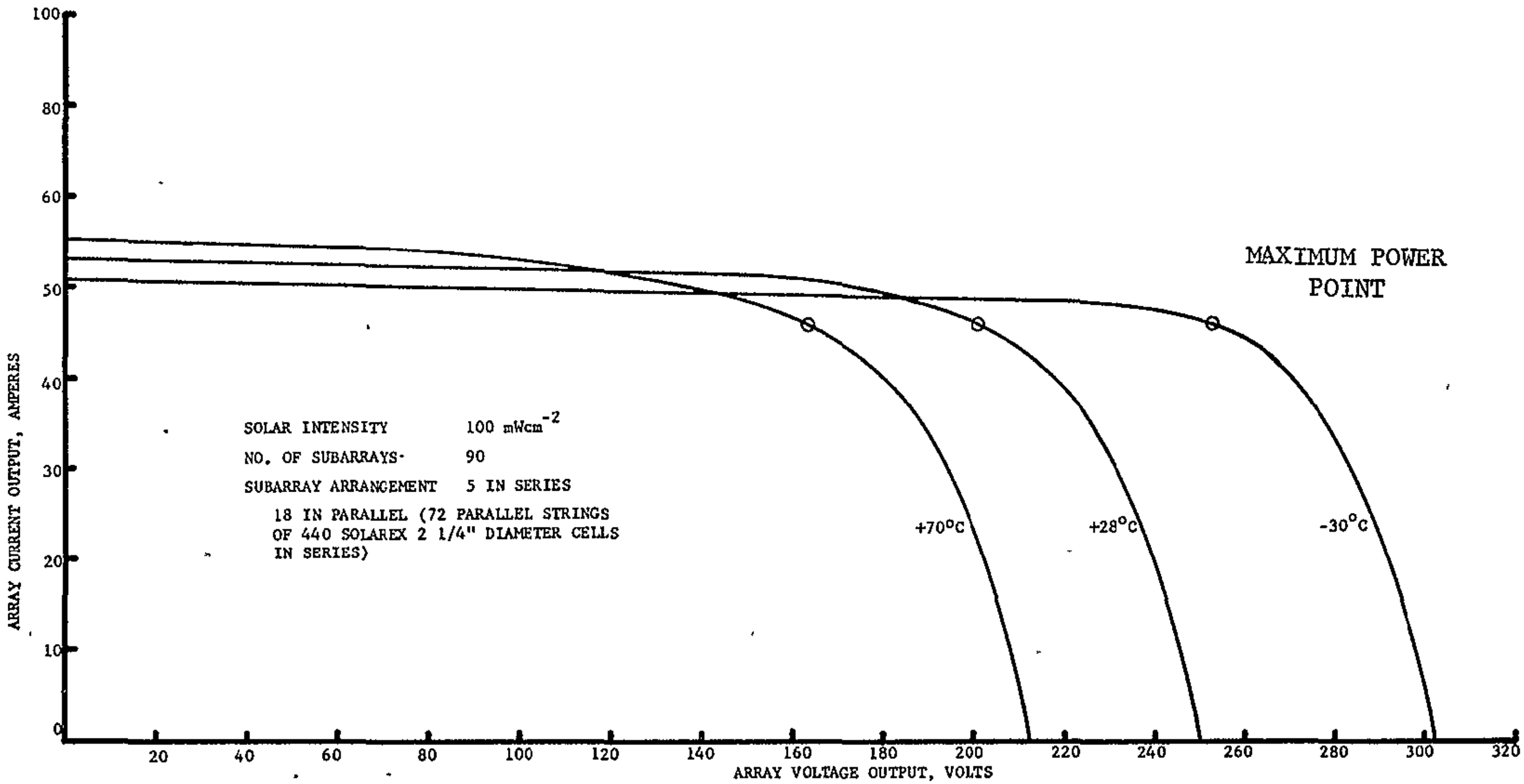


Figure 3-45 I-V Characteristics of PST Baseline Solar Array Configuration

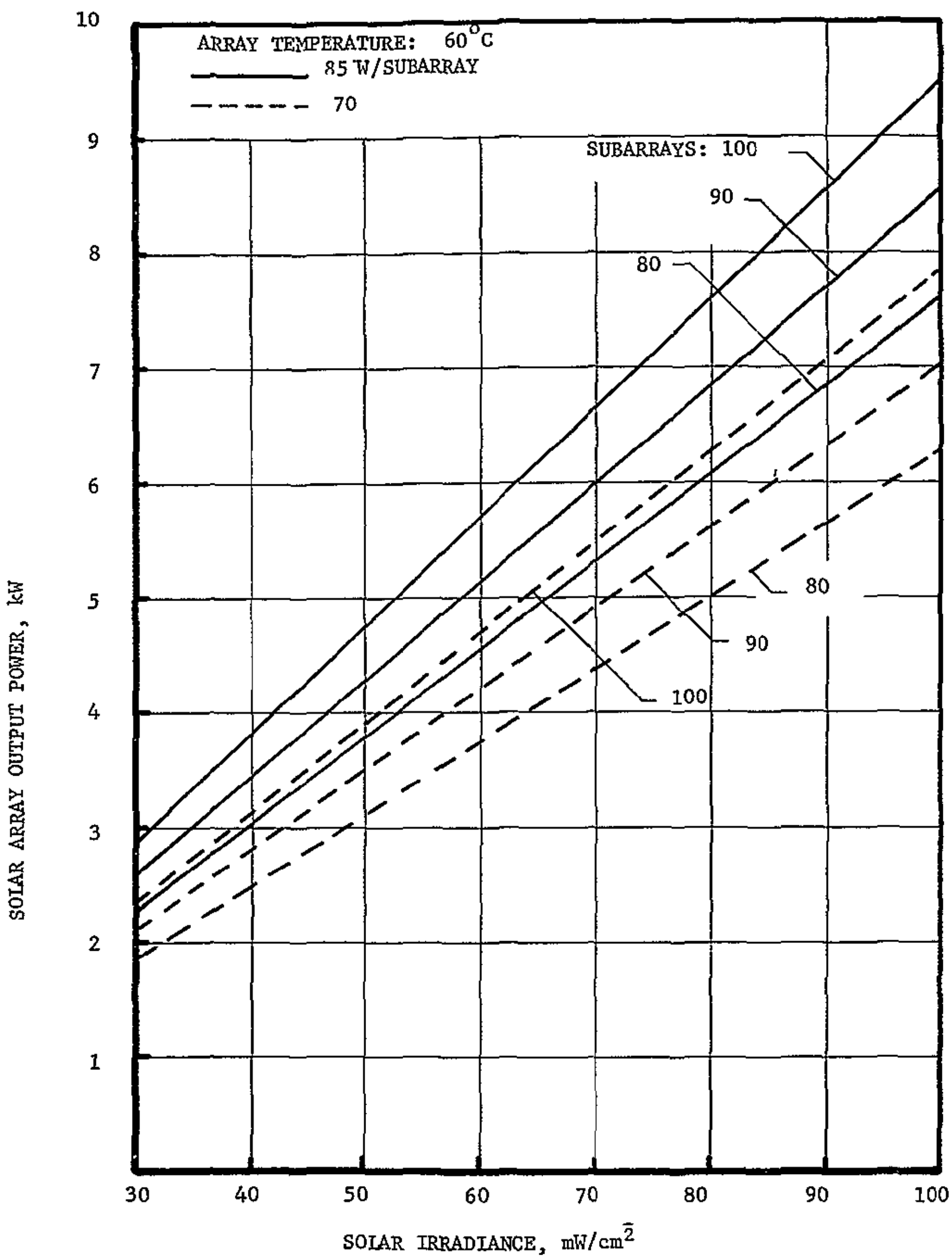


Figure 3-46 Effects of Solar Intensity on Array Output

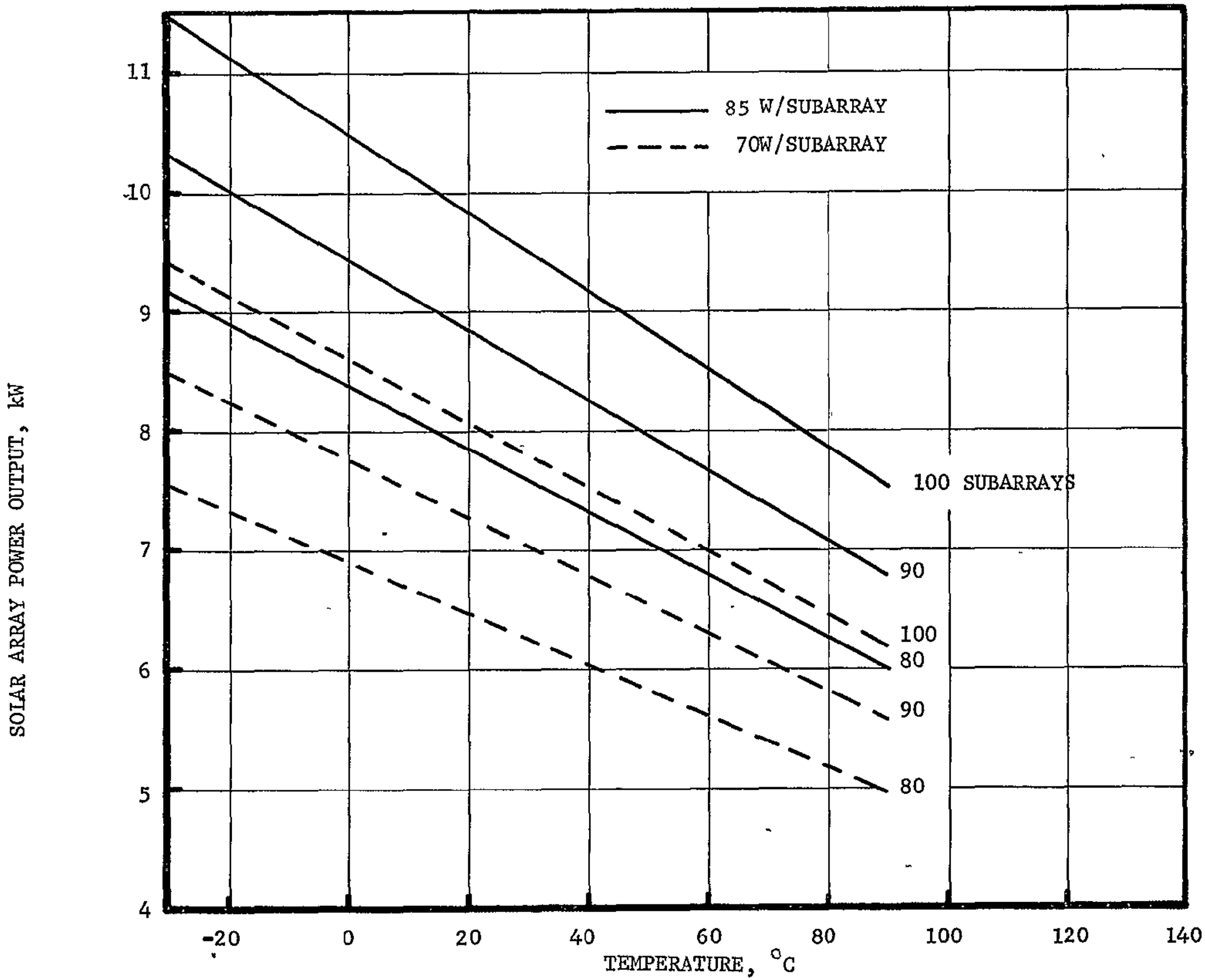


Figure 3-47 Effects of Temperature on Array Output

nominal discharge voltage of a 60-cell lead acid battery is approximately 120 volts. (Manufacturers generally suggest for calculations an average discharge voltage of 1.94 volts/cells or 116.4 volt at the battery level.)

Table 3-22 Partial List of Available Static Inverters

MFR/Model	Output, kVA	Input, Voltage, Vdc	Volume ft^3	Weight, lb	Approximate Cost $
<u>Elgar</u>	1 to 20	105 to 140	31	1000	5,450.00
INV-502	5.0	105 to 140	38	1400	9,950.00
INV-103	10.0	105 to 140	60	2000	13,500.00
<u>Nova</u>	1 to 3	22 to 350			
1K60-150	1.0	105 to 150	1.1	100	1,360.00
2K60-150	2.0	105 to 150	3 1	200	2,140.00
3K60-150	3.0	105 to 150	3.6	325	3,700.00
<u>Abacus</u>	0.5 to 6.0	48 to 140			
423-4	2.0	100 to 140	2.7	90	3,000.00
443-4	4.0	100 to 140	5.0	210	5,600.00
463-4	6.0	100 to 140	16	390	7,900.00
<u>Topaz</u>	0.2 to 3.0*	12 to 125†			
1000 GZ	1.0	105 to 140	1.0	95	
2000 GZ	2.0	24 to 32†	2.0	190	
3000 GZ	3.0	24 to 32†	3.0	285	
<u>Sola</u>	1.2 to 10				
26-1040	10.0	120 Nom	16	1700	10,252.00
<u>Deltec</u>	0.3 to 10	120 Nom			
DI-1203	1.2	125 Nom	1.4	110	1,090.00
DI-1803	1.8	125 Nom	2.6	195	1,740.00
DI-3003	3.0	125 Nom	6.2	475	2,995.00
DI-5003	5.0	125 Nom	6.2	525	3,450.00
DI-10003	10.0	125 Nom	44	1050	6,510.00

*10kVA Unit Reportedly Manufactured.

†125 Vdc Nominal Input Voltage not Available, all Models.

The maximum recommended charge voltage is 2.4 volts per cell or a maximum battery voltage of 144 volts. Hence, the battery voltage criterion is satisfied with a 60-cell unit.

<u>Depth-of-Discharge Constraint</u> - A critical parameter for battery and system operation is the maximum allowable depth-of-discharge. Removing 100% of the battery energy on each discharge seriously reduces battery cycle life. Thus, a percentage of the total battery energy must remain after discharge. This derates

the battery capacity from the nameplate value. For example, the actual capacity available from a 250-ampere-hour battery operated with a 70% depth-of-discharge is 175 ampere hours. The relationship between other system parameters and the depth-of-discharge is shown in Figure 3-48. The figure shows that at various constant loads and a fixed battery capacity (250 A-h), the depth-of-discharge required to satisfy the load demand can vary considerably depending on the average inverter efficiency.

Battery Sizing - The following factors affect the battery size:

(1) Array/battery energy balance criteria (i.e., 24-hr, or 72-hr basis);

(2) Solar array size;

(3) Solar array temperature;

(4) Sunlight duration;

(5) Solar intensity level;

(6) Battery depth-of-discharge constraint;

(7) Power system component efficiencies and system loss factors.

These factors, except for the battery depth of discharge constraint, are included in the following simplified relationship between the solar array power and the bus power available during a 24-hour period (i.e., assuming a 24-hour energy balance requirement with a battery supplying the bus power during the night portion of the 24-hour period):

$$P_{SA} = KP_{BUS} \quad (3\text{-}1)$$

$$= \frac{t_n/t_D}{\gamma_1} + \frac{1}{\gamma_2} \quad P_{BUS} \quad (3\text{-}2)$$

where

P_{SA} = Average solar array power available during sunlight duration

P_{BUS} = Average power available during the 24-hr period

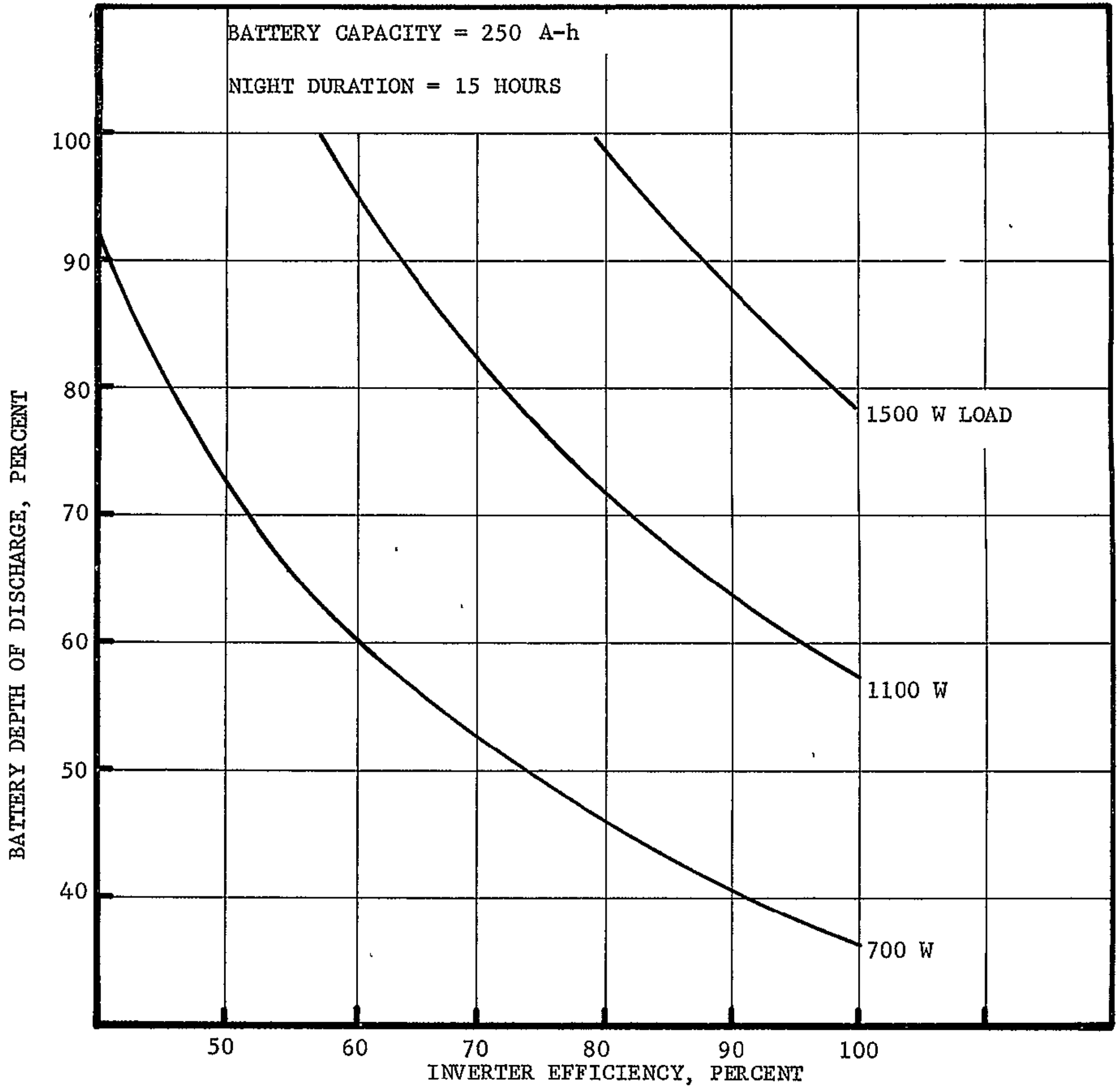


Figure 3-48 Effects of Inverter Efficiency on Battery Depth-of-Discharge at Various Loads

K = Reciprocal of the total system energy efficiency, consisting of component efficiencies, system loss factors, and day and night duration.

γ_1 and γ_2 = Product of system and component efficiencies during night and day durations, respectively.

A detailed derivation of above equation is presented in Appendix A. The required capacity of the battery can be related to the average bus power available using the following equation:

$$C_R = \frac{P_{BUS}\, T_N}{C_D V_D\, {}_R\, {}_{RL}} \times 100 \qquad (3\text{-}3)$$

where

C_R = Rated battery A-h capacity

C_D = Battery depth of discharge constraint in percent

V_D = Average battery discharge voltage

${}_R$ = Average inverter efficiency

${}_{RL}$ = Line loss factor, inverter to bus

T_N = Night duration

The required battery capacity required, C_R, can then be related to the available solar array power by combining like terms in equations (3-1) and (3-3). This results in

$$C_R = \frac{P_{SA}\, T_N}{K C_D V_D\, {}_R\, {}_{RL}} \times 100 \qquad (3\text{-}4)$$

Using the results of solar array performance data generated by the PST computer program in equation (3-4), the battery capacity required for three potential PST sites were determined. Figure 3-49 shows the required battery capacity for Cleveland, Denver, and Phoenix in terms of the daylight duration. In all cases, the maximum battery capacity required occurs at the equinox (i.e., at daylight duration of 12 hours). Its magnitude differs for three sites because of the difference in the average solar insolation available at these sites. This difference in the solar insolation

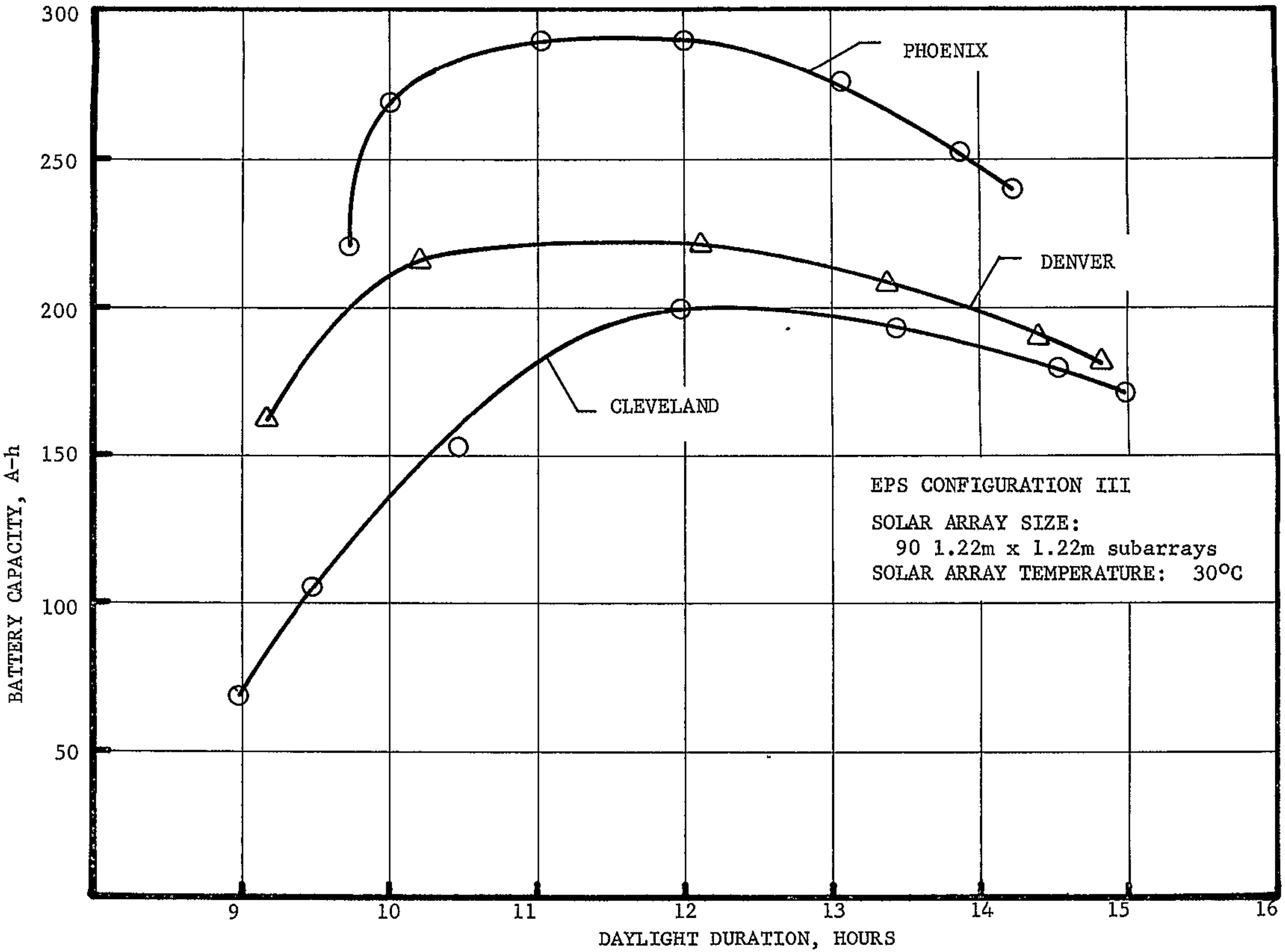


Figure 3-49 Battery Capacity Required as a Function of Daylight Duration

is depicted in Figure 3-50 which shows the available average solar array output power as a function of the sunlight duration. The required rated battery capacity required for the three cities are listed in Table 3-23. This sizing analysis was based on EPS Configuration III using sizing analysis the following assumptions and criteria:

(1) Energy balance condition for a 24-hour day/night period is to be met.

(2) Maximum battery depth of discharge of 70%.

3.6.5 Inverter

Power Loss - The inefficiency of an inverter is caused by: (1) the no-load (tare) losses consisting of the control and switching losses, and (2) by the copper or I^2R losses. The tare power is generally independent of the load while the copper losses are directly related to the load current. The combination of these losses produces the typical inverter efficiency curve shown in Figure 3-51. As the load is reduced, the tare power becomes a larger percentage of the input power and the inverter power efficiency, defined as

$$\frac{\text{Power Output}}{\text{Power output + Losses}}$$

decreases accordingly. The efficiency drops off rapidly when the internal losses exceed the inverter output power. Figure 3-52 shows the efficiency as a function of load power for the 13 kVA Westinghouse, PC-16 inverter. The loss at no load is 850 watts and increases to 1600 watts at the eight kilowatt output level. Hence, for an eight kilowatt change in output power, the loss in the inverter increases by only 750 watts. The inverter is consequently a heat source with a minimum output equal to the tare power and a maximum output on the order of twice the tare power.

For optimum conversion of solar array energy to ac electrical energy, the inverter should be sized to operate near the full load efficiency. This poses somewhat of a dilemma on the single inverter on the PST design. Table 3-24 shows load information for Denver supplied by the Public Service Company of Colorado. The data indicates that for established residences the average power is 0.623 kilowatts but the peak demand is as high as 10 kilowatts. The inverter size should be adequate to provide for the peak load and use available energy (from array and battery). However, an inverter sized for a 10 kilowatt peak output would be operating at

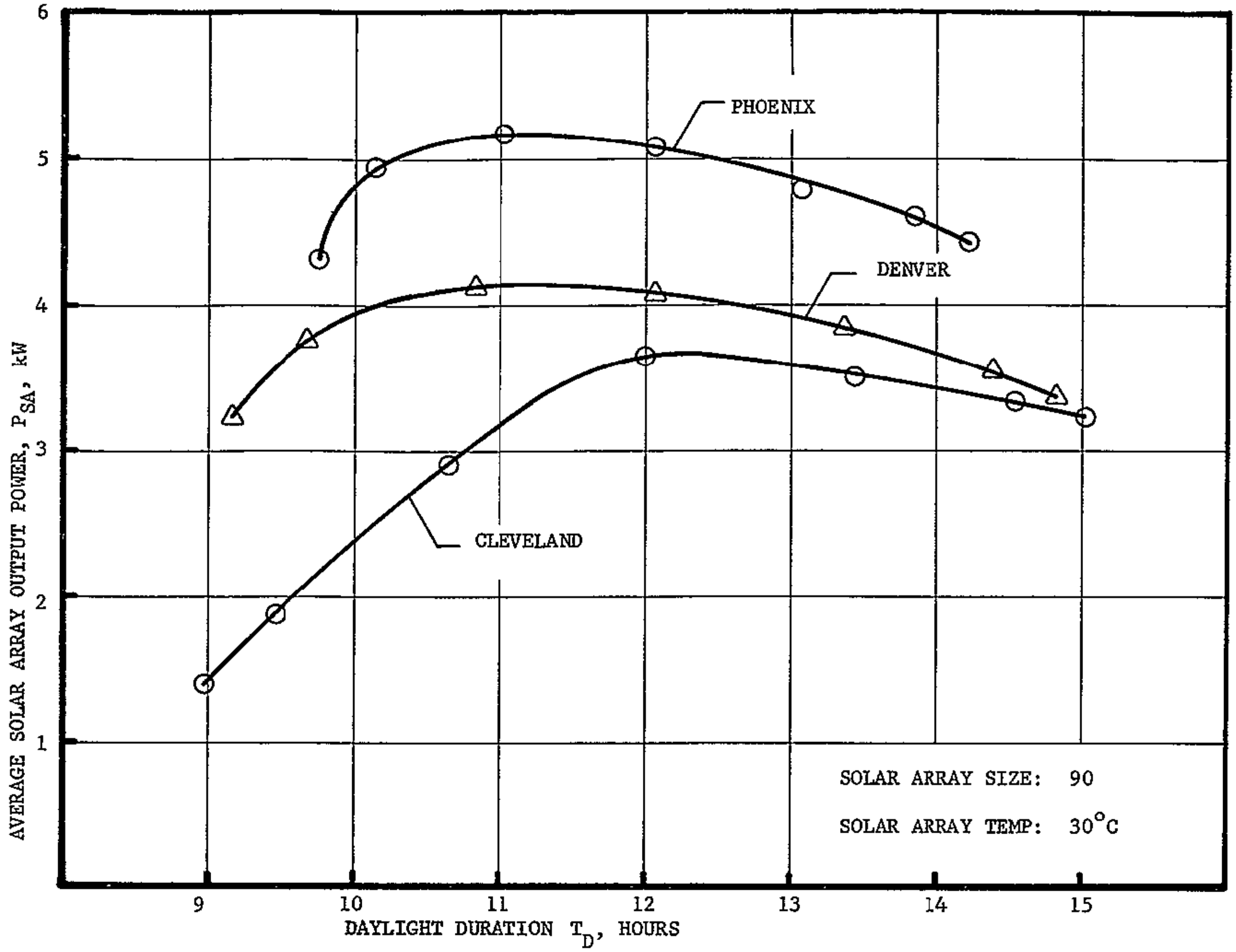


Figure 3-50 Average Solar Array Output Power as a Function of Daylight Duration

Table 3-23 Required Battery Capacity for Three Cities

Site	Battery Capacity*	
	Minimum	Recommended
Phoenix	280 A-h	340 A-h†
Denver	222 A-h	250 A-h†
Cleveland	200 A-h	250 A-h†

*Average battery discharge voltage = 116.4 volts.

†Available size and margin included.

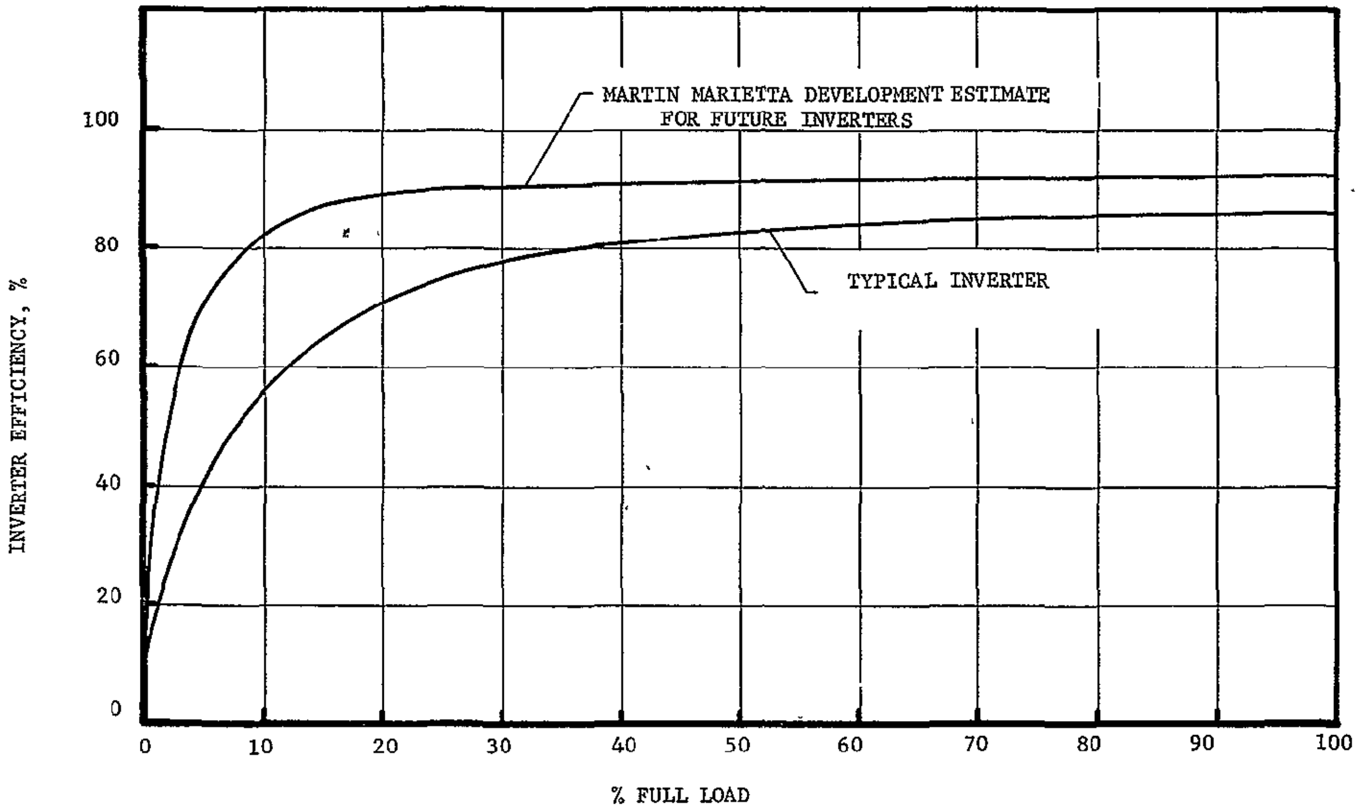


Figure 3-51 Typical and Projected Inverter Efficiency Characteristics

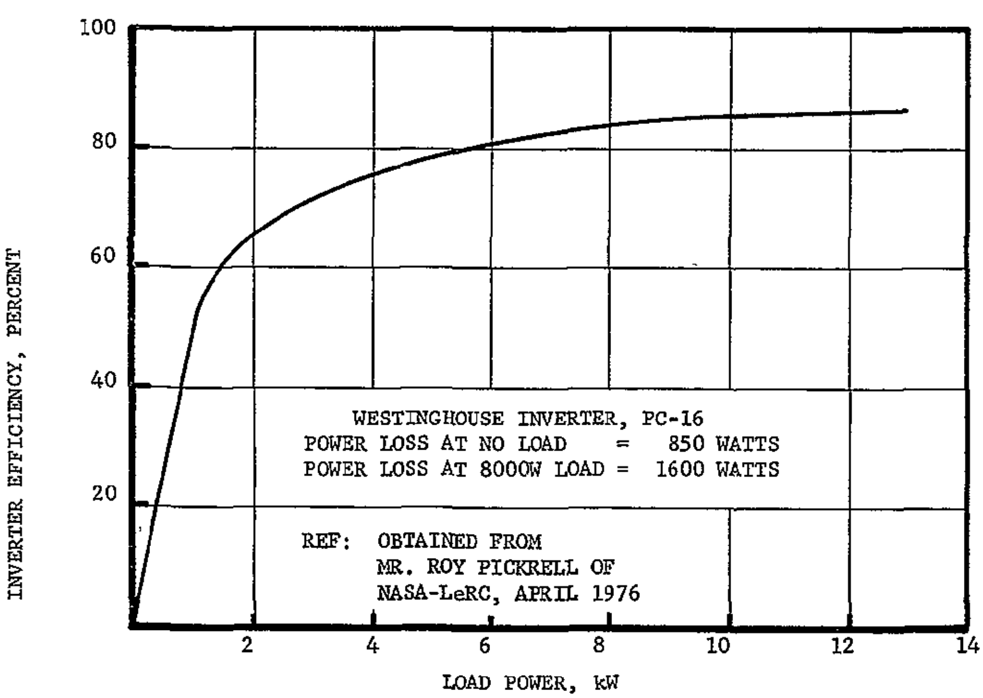


Figure 3-52 Westinghouse PC-16 Inverter Efficiency

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less than 1/10 the full load capability when supporting the average residential load. As illustrated in Figures 3-51 and 3-52, this is a very inefficient region for inverter operation. This problem could be mitigated by increasing the inverter efficiency with the use of of new inverter technology. A comparison between Martin Marietta's projected development and a typical inverter is shown in Figure 3-51. This high efficiency operation at low levels could also be simulated at present by using multiple inverters. A one-kilowatt and 10-kilowatt inverter could be used to construct an efficiency characteristic much less dependent on load power. A number of inverters used together results in an efficiency virtually independent of the load. Further details of the multiple inverter concept are given in Section 4.0.

Table 3-24 Average Residential Loads for Denver (Public Service Company of Colorado)

Type of Residence	Average kW-h/month	Average Power, kW
Established Residences* (Including Apartments and Residential Homes)	449	0.623
New Residences	550 to 600	0.763 to 0.833
All Electric† (for Month of January)	3379	4.69

*7 to 10 kW Peak Demand Without Electric Heat.

†Ranged from 1791 to 5726 kW-h/month.

The impact of the inverter efficiency is illustrated in Figure 3-10 for the configuration with battery. For this case the average inverter efficiency must exceed 20% for any bus power capability to exist.

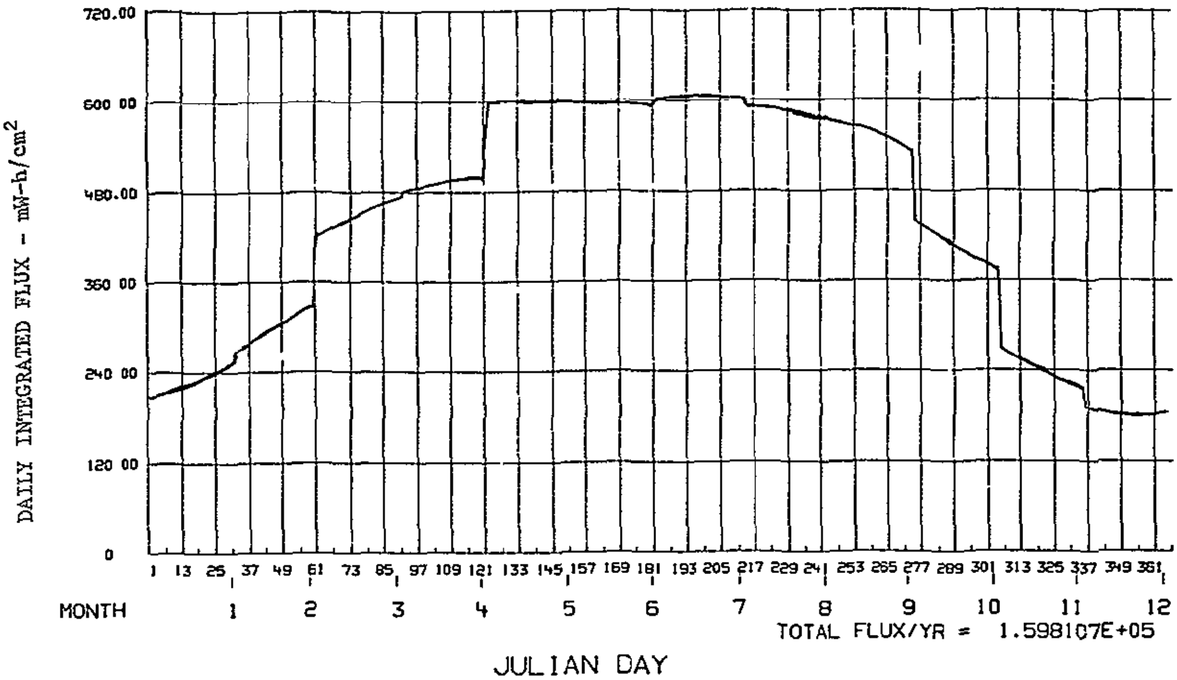
For the configuration without the battery, the inverter is the only power conditioning component in series with the power flow. Thus, inverter efficiency primarily determines system efficiency. In this mode of operation, the inverter functions differently than in the battery case. The amount of power fed back to the utility is controlled by the inverter output phase firing angle. Therefore, the utility grid acts as a regulated variable load to the inverter. When abundant array power is available, the inverter output will be close to full load insuring a high efficiency. As array output decreases, the inverter efficiency will fall off; however, when the inverter efficiency drops to a low value there is only a small amount of array power available. Thus, the total losses are minimal when the efficiency is low and maximum inverter efficiency is obtained when maximum array power is available.

3.6.6 System Performance

The PST system performance is dependent on site location. The pacing parameters for the Electrical Power System (EPS) are the solar array power and energy output. These parameters are primarily a function of atmospheric conditions and the daylight duration. Array temperature also affects the array power output but to a lesser extent.

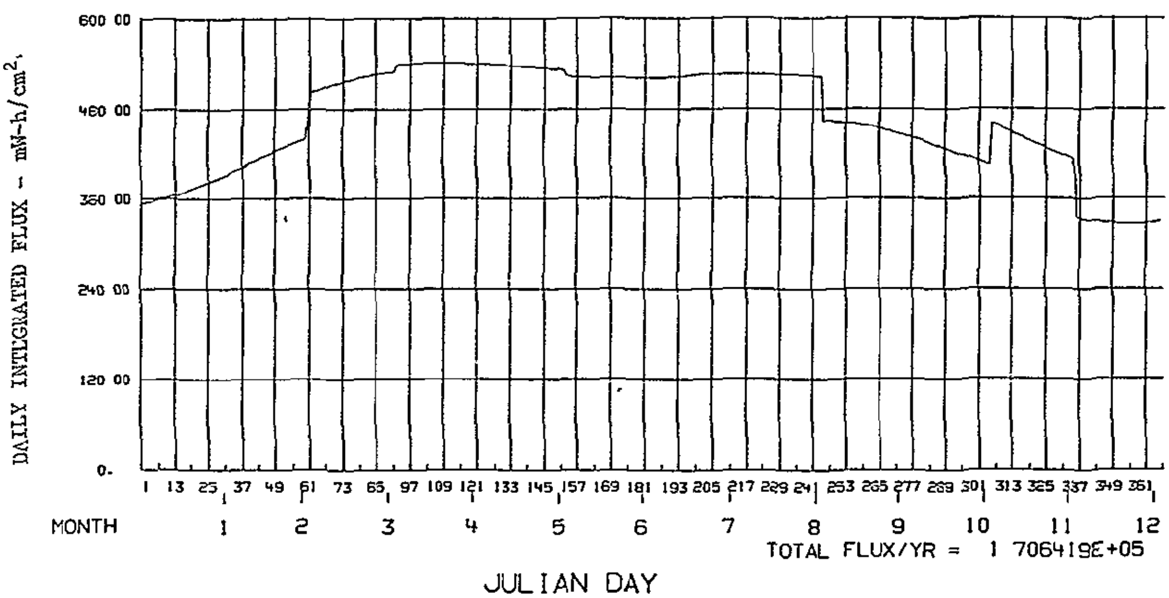
Figure 3-53 shows the daily integrated flux for Gainesville and Cleveland. The daily integrated flux is the total energy ($mW\text{-}h/cm^2$) that falls each day on a surface tilted at the site latitude. Figure 3-54 shows the steady-state flux per day for the same sites. The steady-state flux is the average power that falls each day on a surface tilted at the site latitude. It is interesting to note the difference between the two sets of curves. The average daily steady-state flux (power density) peaks at both of the equinoxes. At these points the sun's rays are nearly normal to the array surface, thus the solar insolation maximizes. This curve for both sites dips down between the equinoxes but the energy curve (daily integrated flux) remains relatively constant between these points. The dip in average power is caused by the angle formed between the sun's rays and a normal to the receiving surface. This angle increases as the sun approaches the summer solstice and then decreases as the sun returns to the equinox. However, during these months the daylight duration is increasing. Therefore, the power time product (energy) remains relatively constant. Because the solar array output is proportional to the solar intensity, the array power and energy profiles are mere reflections of the solar irradiance profile.

The average array output per day for Cleveland and Gainesville are shown in Figures 3-55 and 3-56, respectively. The sag in power output between the equinoxes is more pronounced because of the curve scaling factor. The large sharp jumps in the total daily array energy are caused by seasonal cloud factors. The difference between the shape of the curves for Cleveland and Gainesville is caused primarily by these cloud factors.



CLEVELAND, OHIO -- 1976

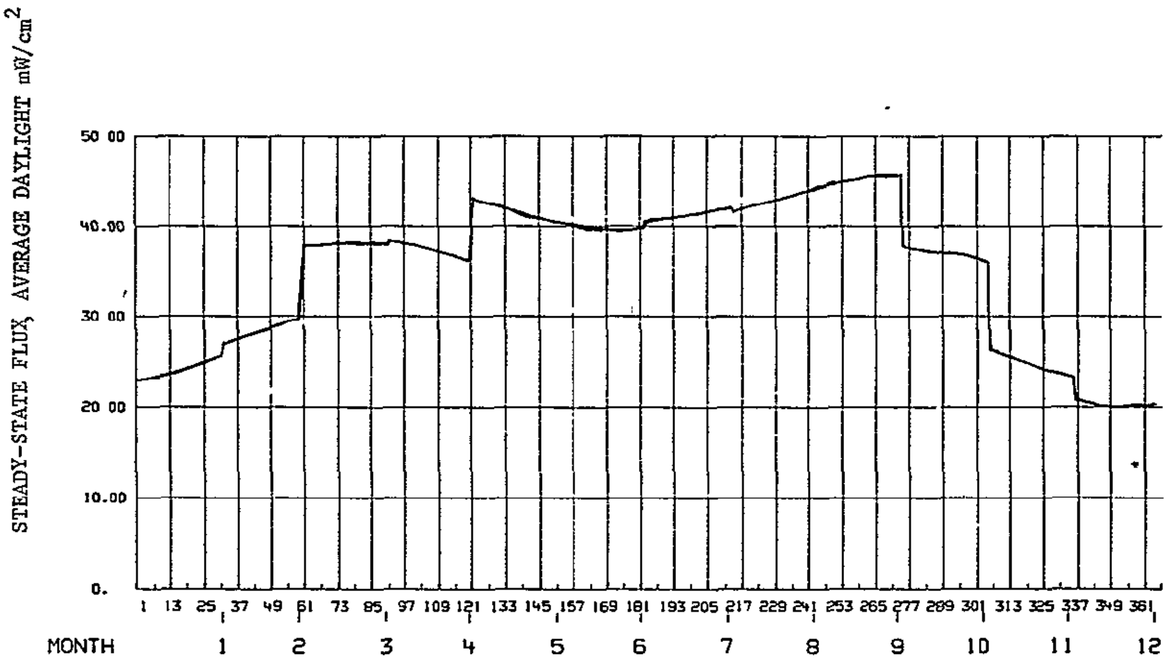
LAT = 41.50 LONG = 81.70



GAINESVILLE, FA -- 1976

LAT = 29.66 LONG = 82.33

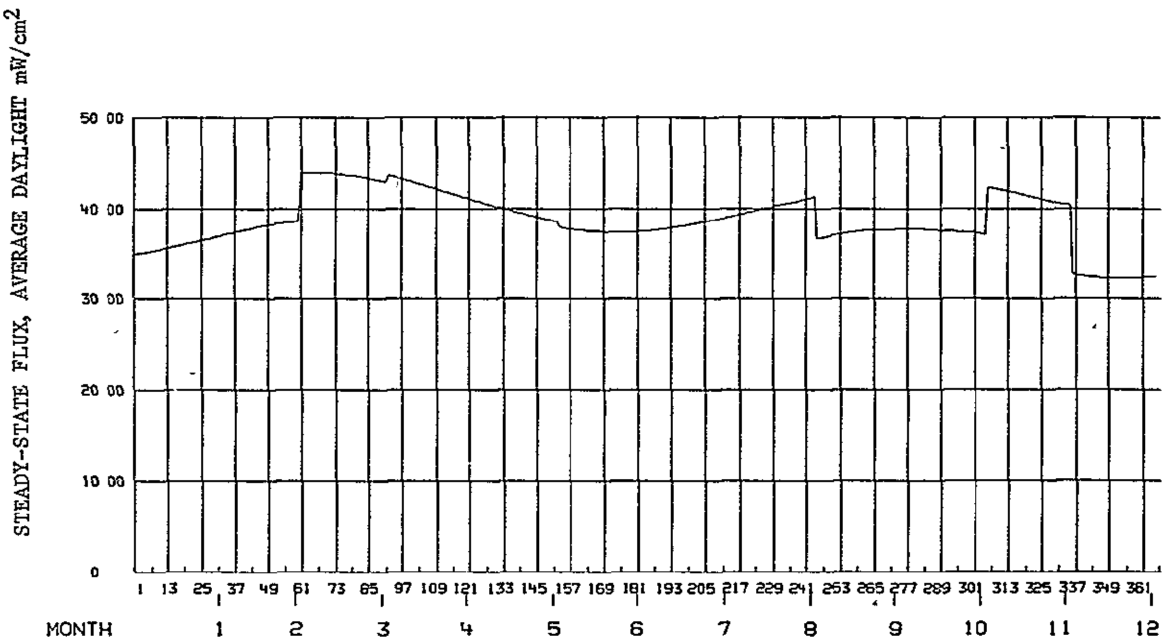
Figure 3-53 Daily Integrated Flux for Cleveland and Gainesville



JULIAN DAY

CLEVELAND, OHIO -- 1976

LAT = 41.50 LONG = 81.70



JULIAN DAY

GAINESVILLE, FA -- 1976

LAT = 29.66 LONG = 82.33

Figure 3-54 Steady-State Flux per Day for Cleveland and Gainesville

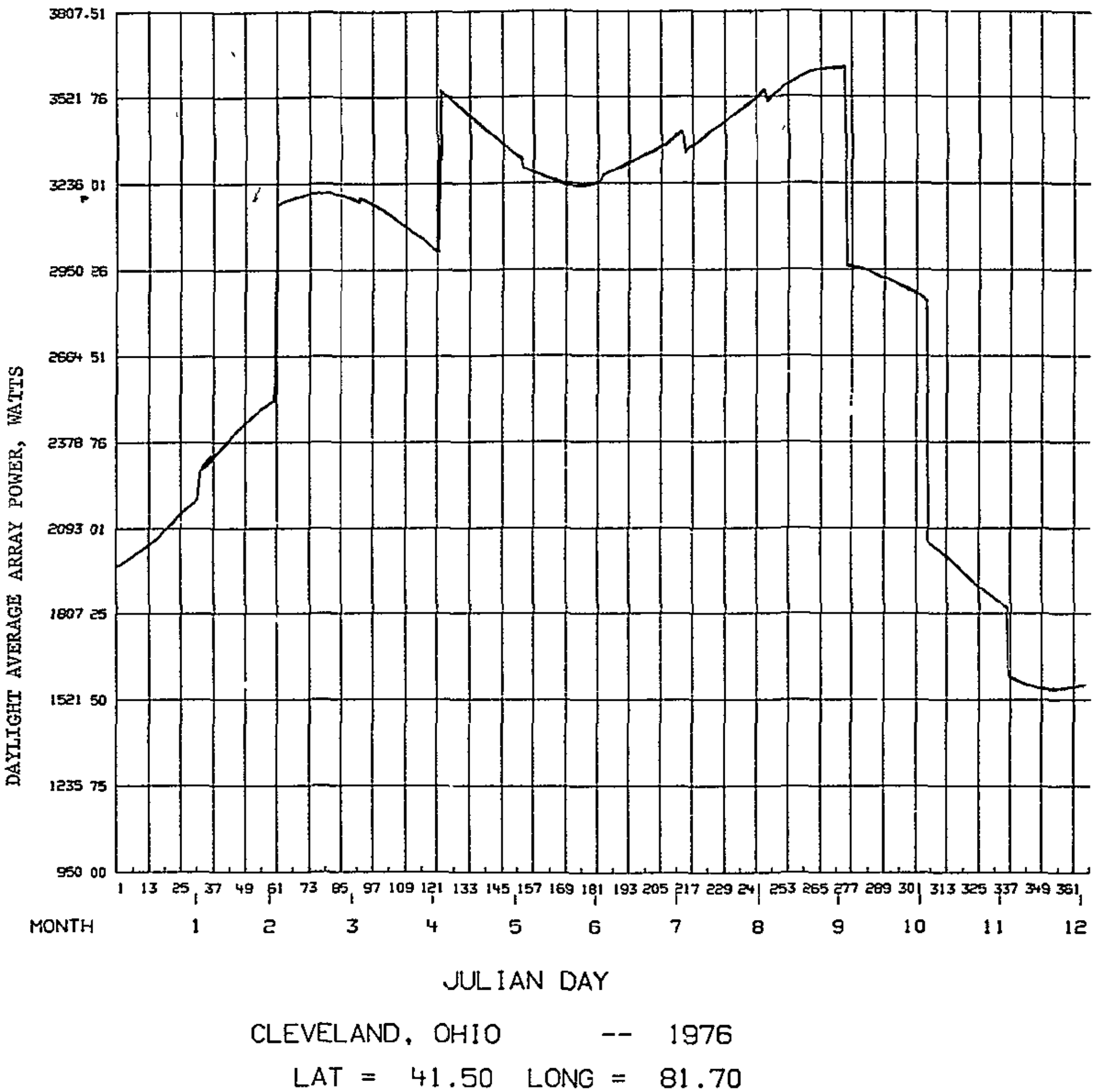


Figure 3-55 Average Daylight Array Power Profile for Cleveland

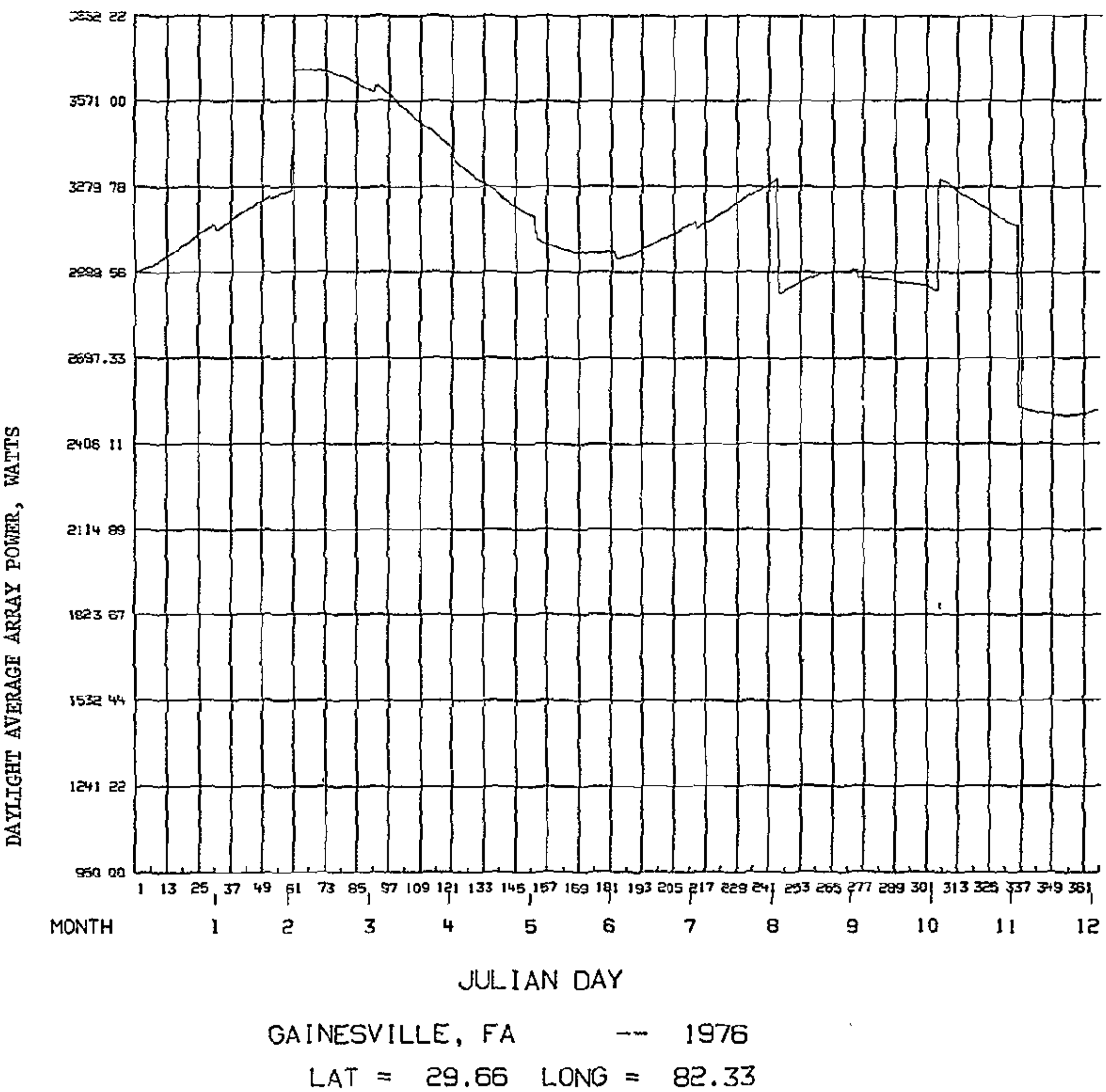


Figure 3-56 Average Daylight Array Power Profile for Gainesville

Other EPS performance factors such as the energy from the PST/day, the average bus power, and the daily energy displacement are directly proportional to the solar array energy output. These are demonstrated in Figures 3-57 through 3-59, respectively, for the baseline PST power system. Note that the relative shape of the curves in these figures are identical. The sinusoidal appearance of the available energy profile (Fig. 3-57) is due to the variation in the daylight duration during the year. Figures 3-60 and 3-61 show this variation in sunlight duration for Cleveland and Gainesville, respectively. As the site latitude is increased, the magnitude of the daylight duration increases.

Using the baseline EPS configuration the power system performance was investigated with and without the battery for each of the five sites. A general index used for comparison was the utility energy required per day, E_U. Figure 3-62 shows a comparison of E_U for five sites using the identical EPS configuration with battery at a bus load of 1100W. Phoenix requires the least amount of utility energy while Celveland has the greatest utility energy requirement throughout the year. For both Phoenix and Denver there is a period of time during the summer months (approximately 8.3 and 4 months, respectively) when no utility energy is required at a total bus load of 1100W. It should be noted that utility energy would be required if the bus load is significantly higher, such as for an all-electric home.

Figure 3-63 shows a comparison of the five sites in terms of utility energy required, again assuming a constant load of 1100W at the bus. The site order and general shape of the utility energy profile is not radically altered from the battery case (Fig. 3-62). The curves just shift along the ordinate. In the no-battery case, only Phoenix requires a small amount of utility energy during December.

The utility area under the curves in Figures 3-62 and 3-63 yields the utility energy required per year at a particular average load.

Cleveland was selected to study the effects of varying average load demands on the utility energy required. The battery case is shown in Figure 3-64. Once again note that the shape of the curve is not altered by the changing load. It is only shifted. The shape of the curve is determined by the available solar energy which is independent of the load. The utility energy per day, E_U, required for Cleveland using the no-battery configuration is shown in Figure 3-65. The E_U is less for the no-battery case because

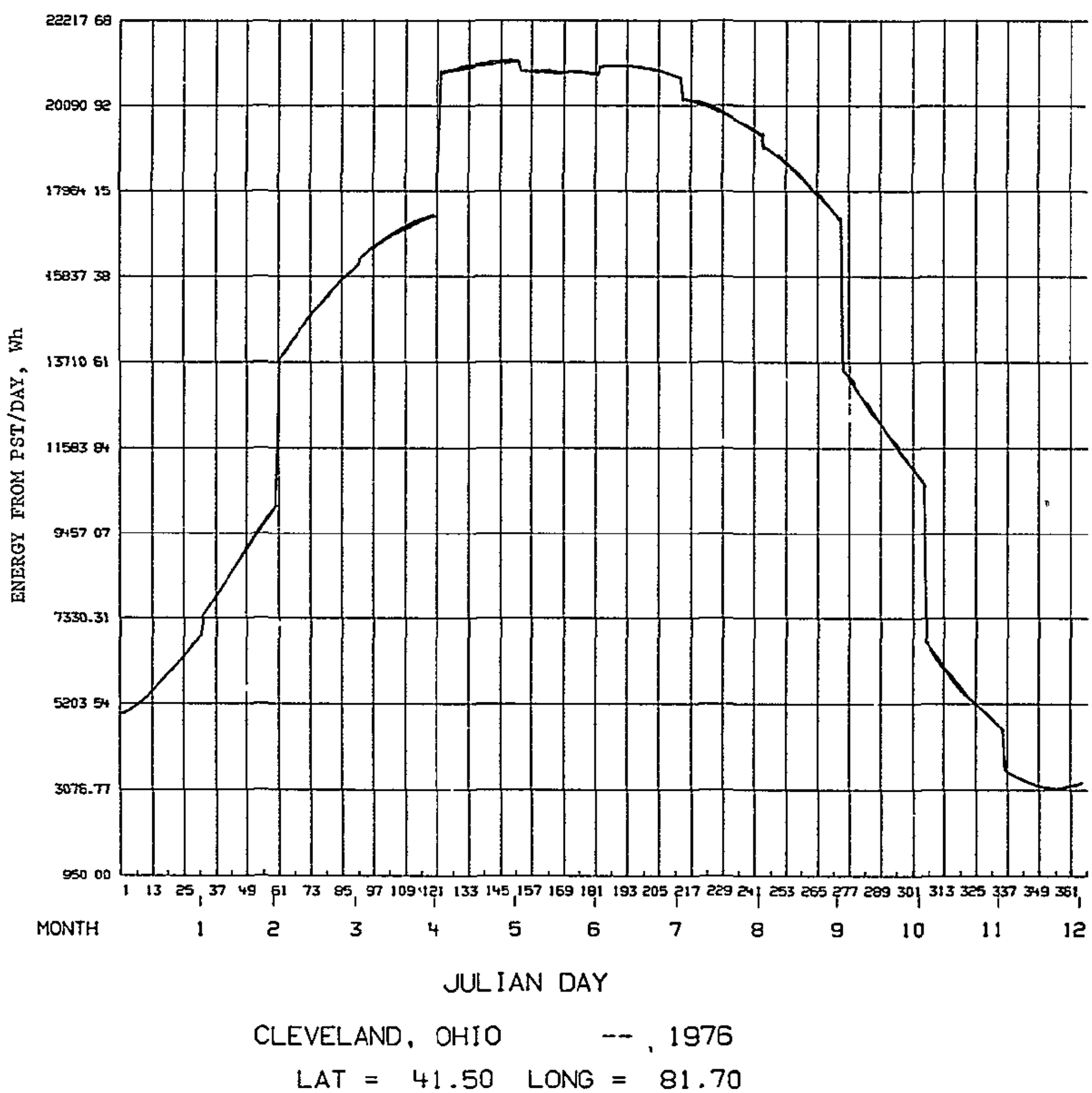


Figure 3-57 Available PST Energy per Day Profile for Cleveland

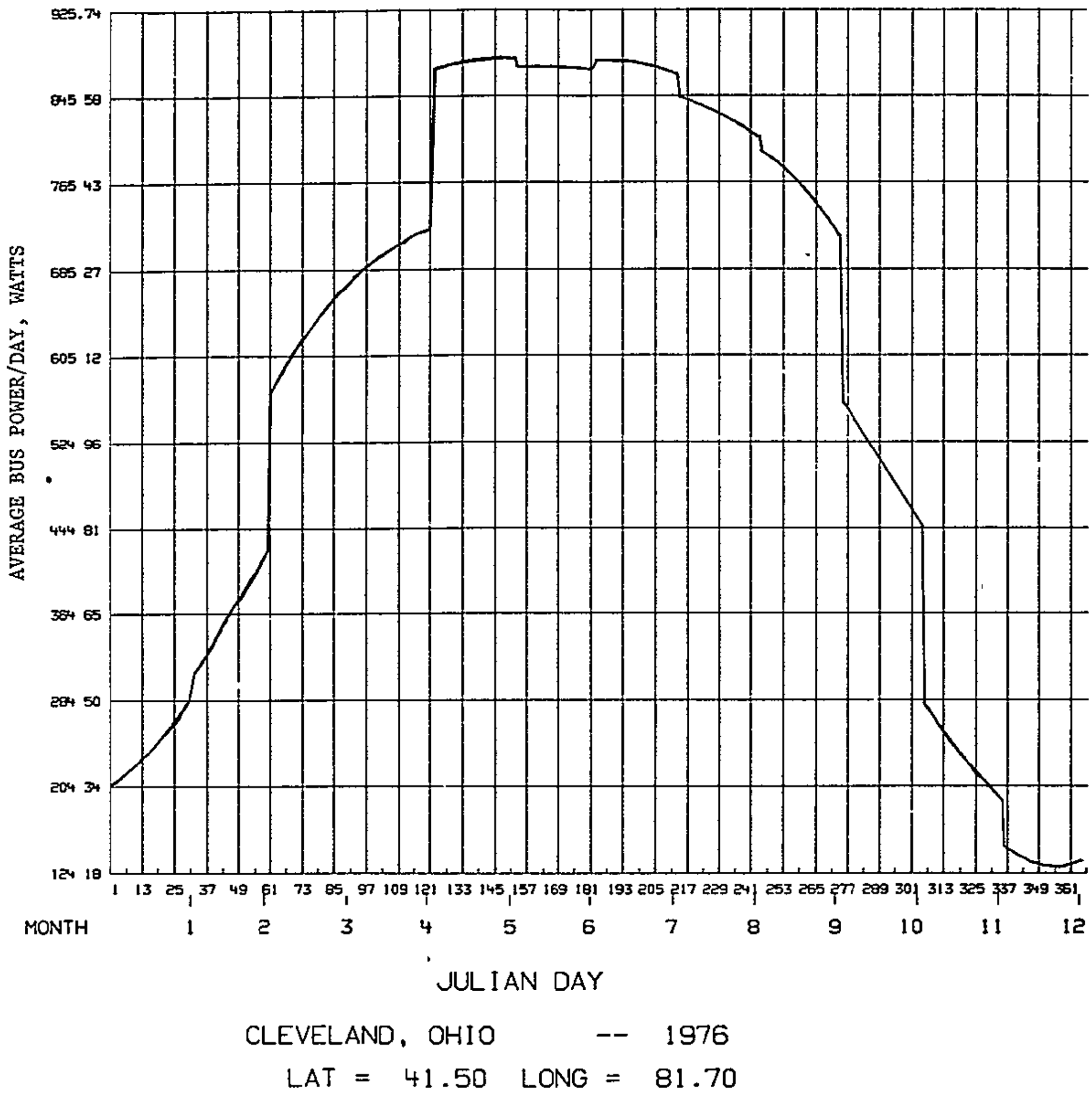


Figure 3-58 Average Daylight Bus Power per Day Profile for Cleveland

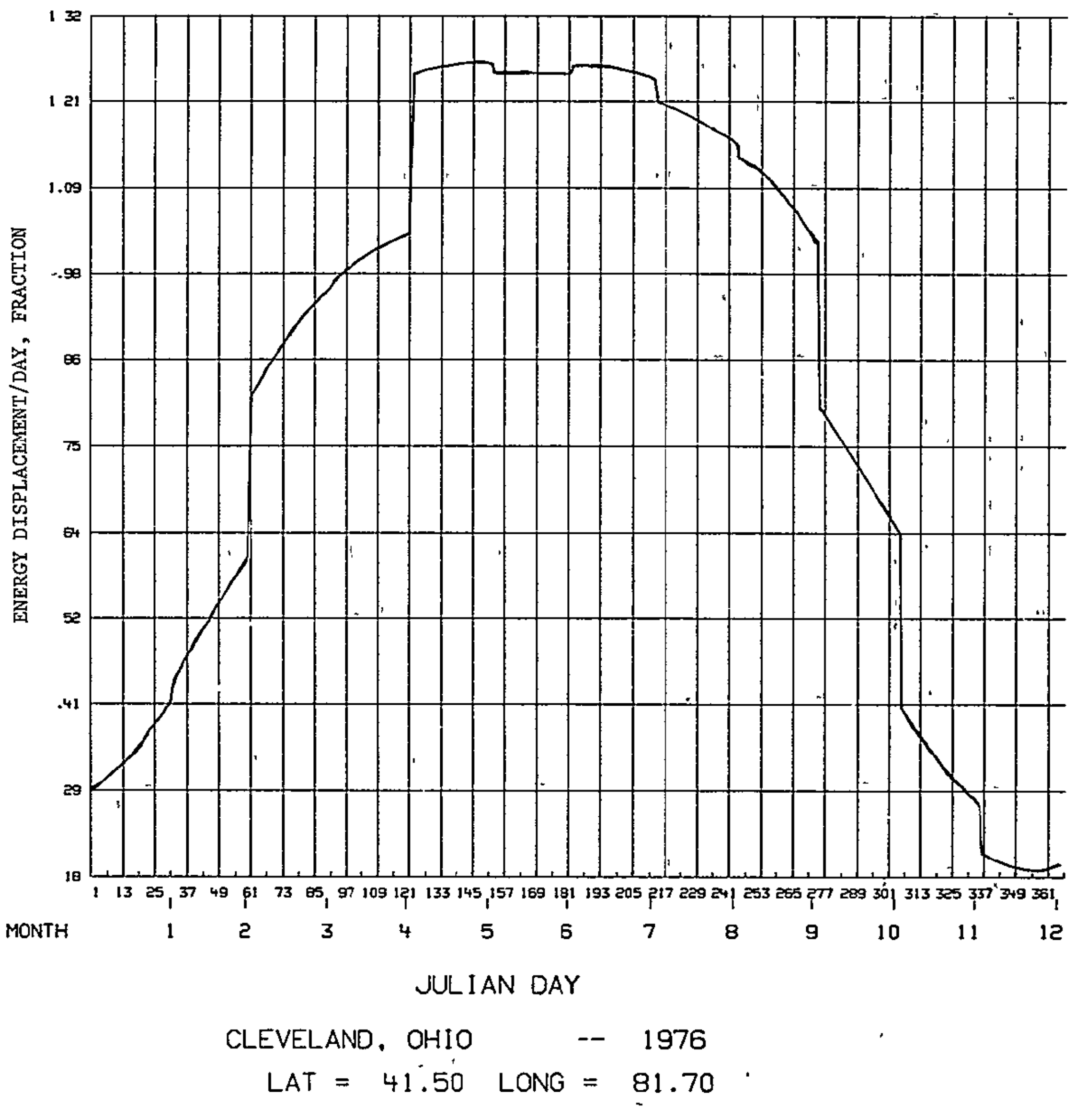


Figure 3-59 Energy Displacement per Day Profile for Cleveland

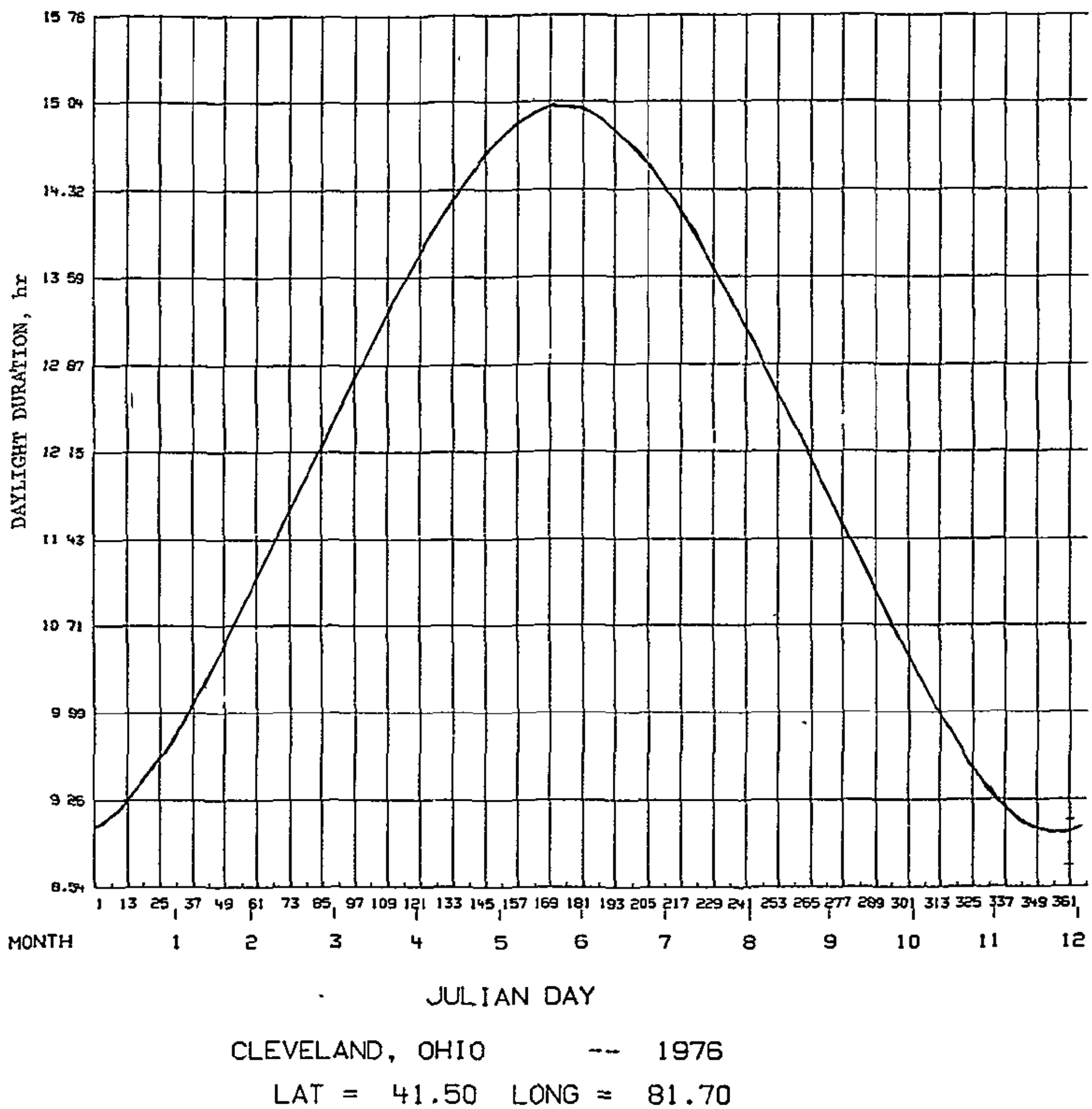


Figure 3-60 Sunlight Duration Variation for Cleveland

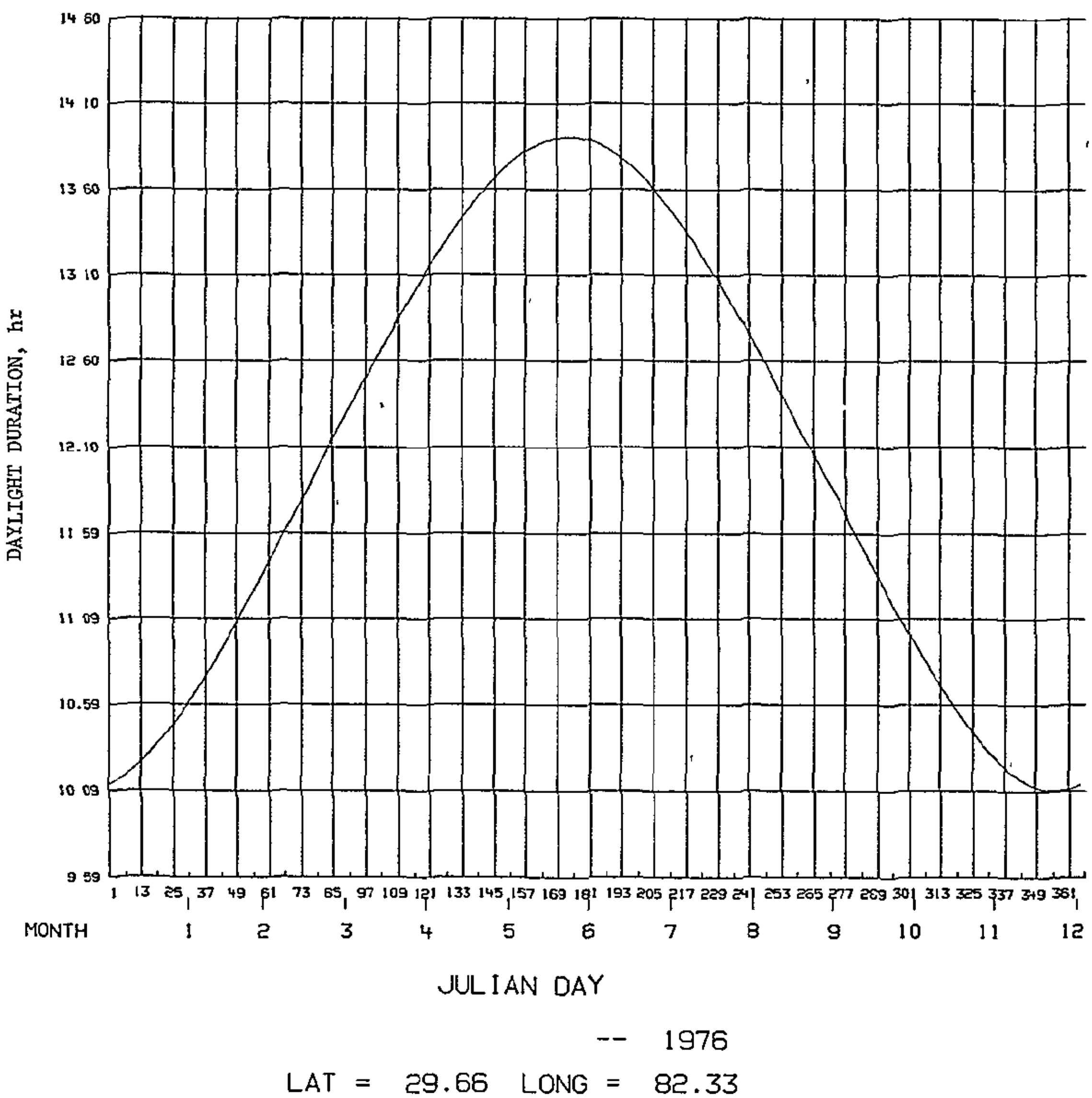


Figure 3-61 Sunlight Duration Variation for Gainesville

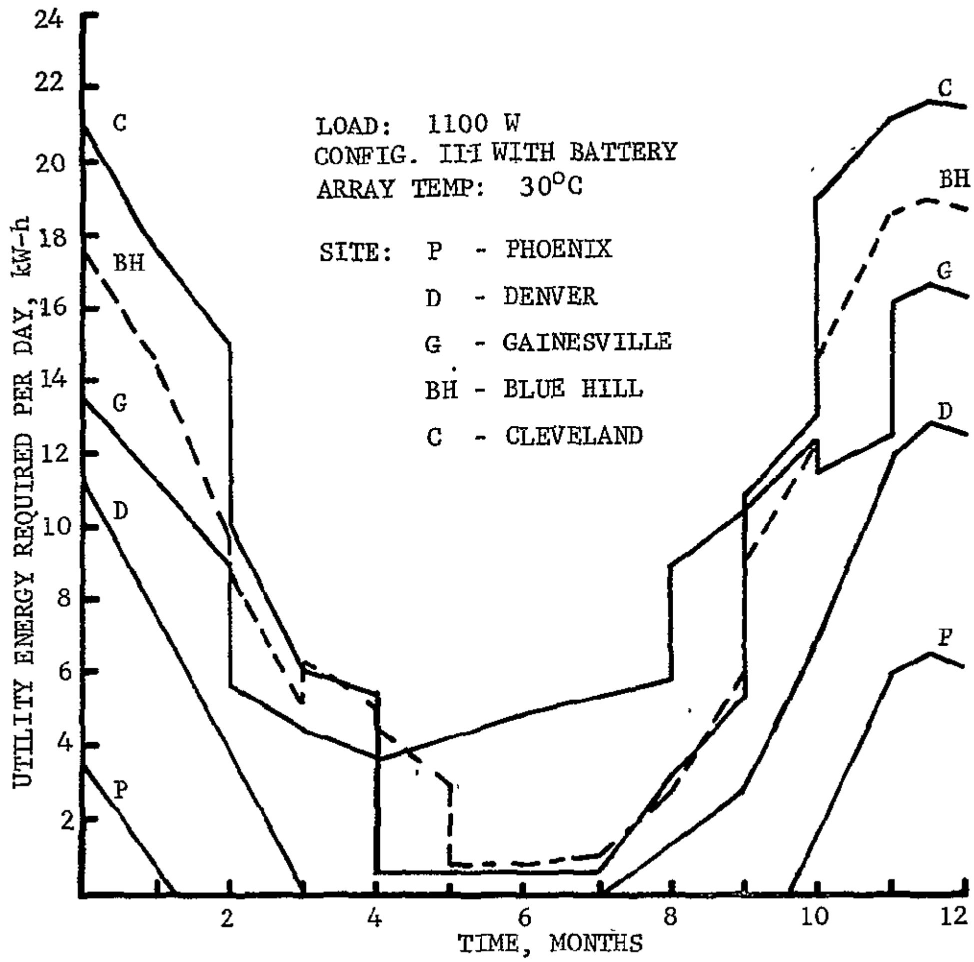


Figure 3-62 Comparison of Required Utility Energy for Five Sites for Configuration with Battery

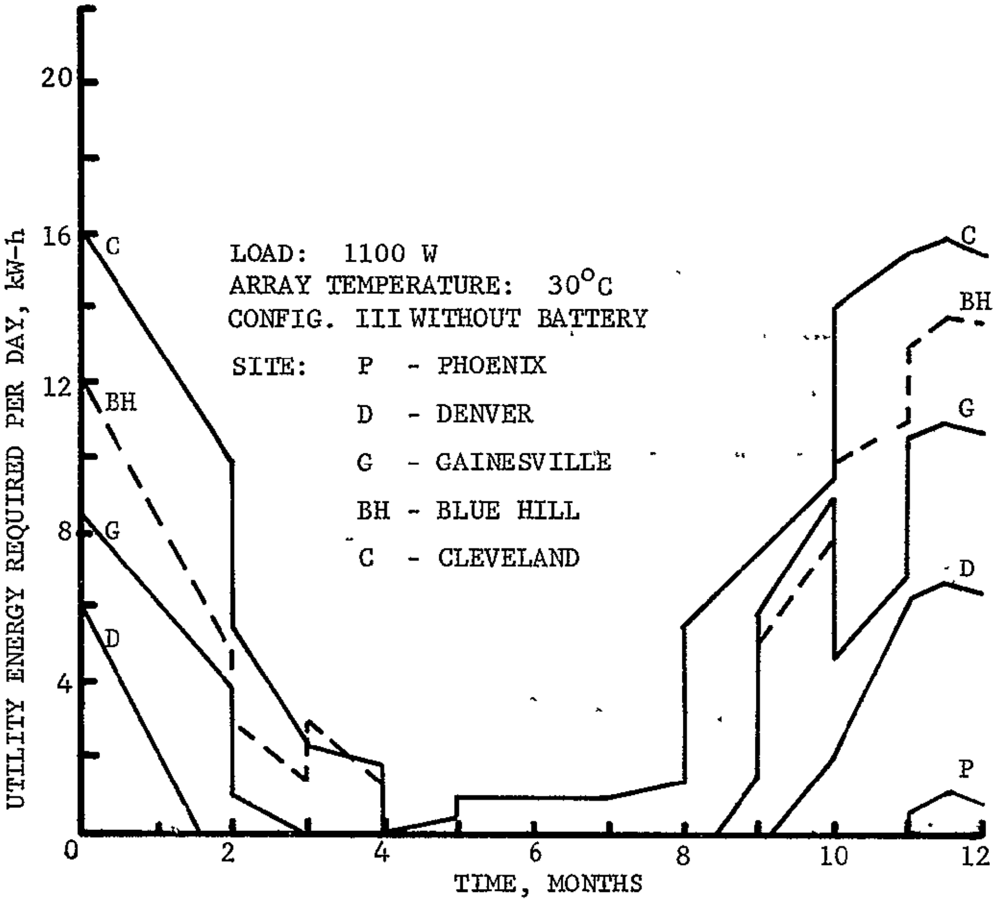


Figure 3-63 Comparison of Required Utility Energy for Five Sites for No-Battery Configuration

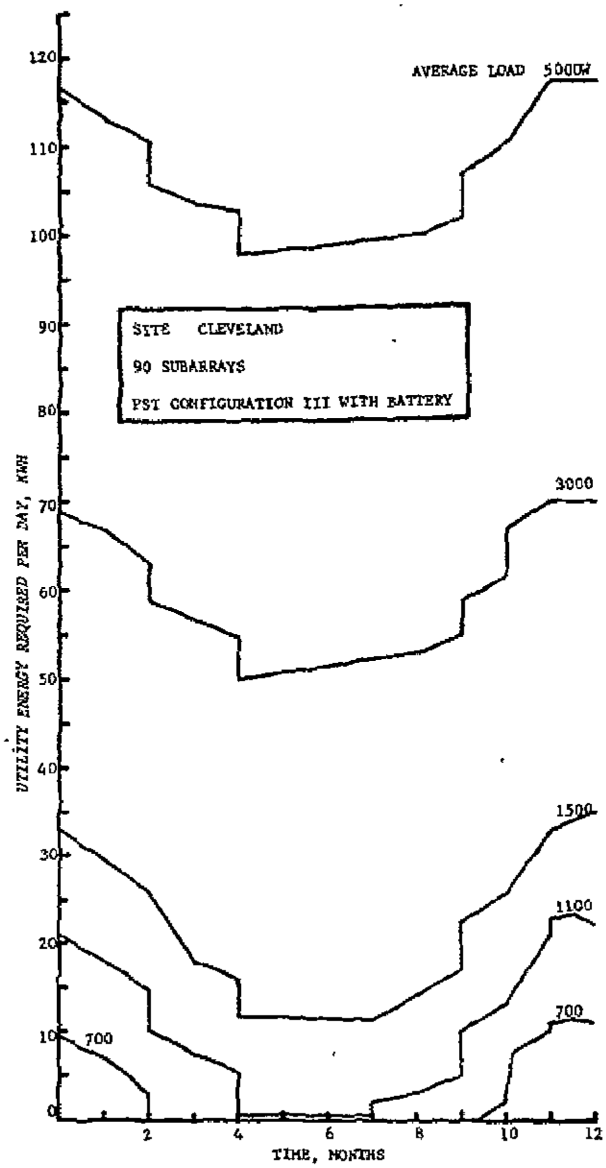


Figure 3-64 Utility Energy Required per Day for Cleveland for Configuration With Battery

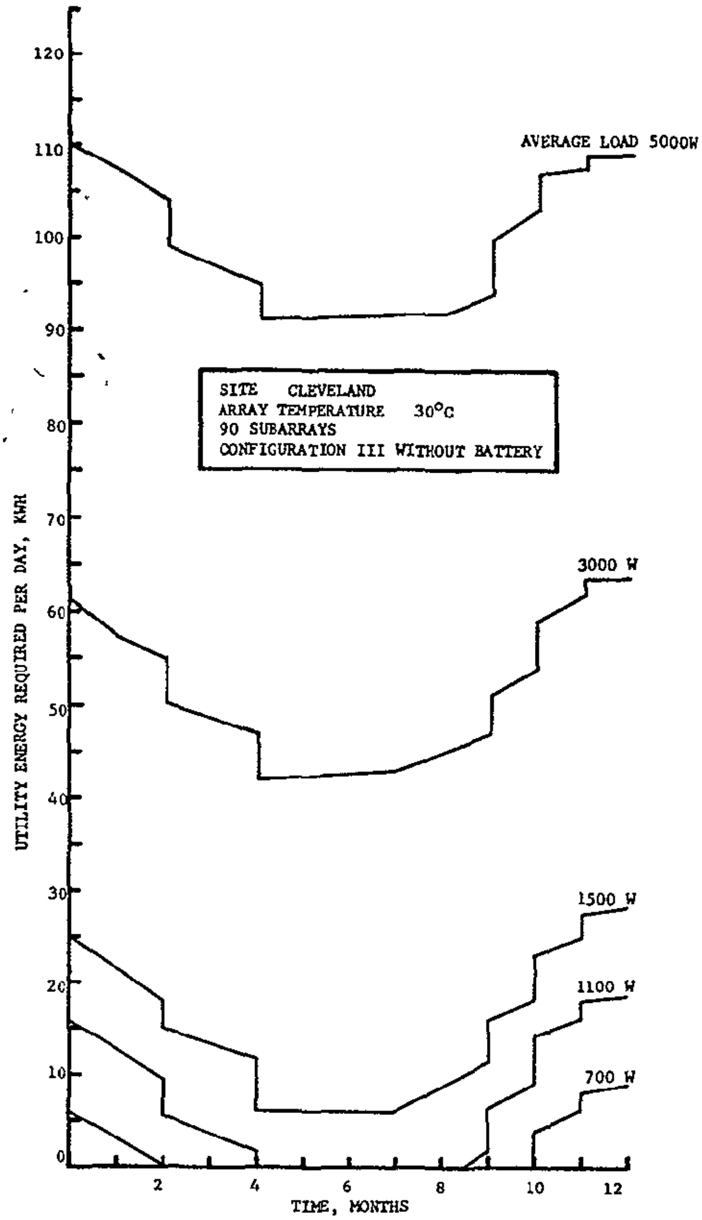


Figure 3-65 Utility Energy Required per Day for Cleveland for No-Battery Configuration

the battery recharge energy is not required and most of the array energy is available to the load.

The total annual utility energy requirement for Cleveland (as a function of load) is shown in Figure 3-66. The configuration with the battery requires between three and six MW-h of utility energy more than the no-battery configuration.

The effects of array temperature on the EPS performance are illustrated in Figure 3-67 for Cleveland. An increase in temperature from 30 to 50°C causes a 1 kW-h/day increase in the utility energy required at a constant 700-W load. This indicates that the array temperature could have a significant effect on the energy displacement. Thus, the actual PST array design should consider methods of minimizing the effective array temperature.

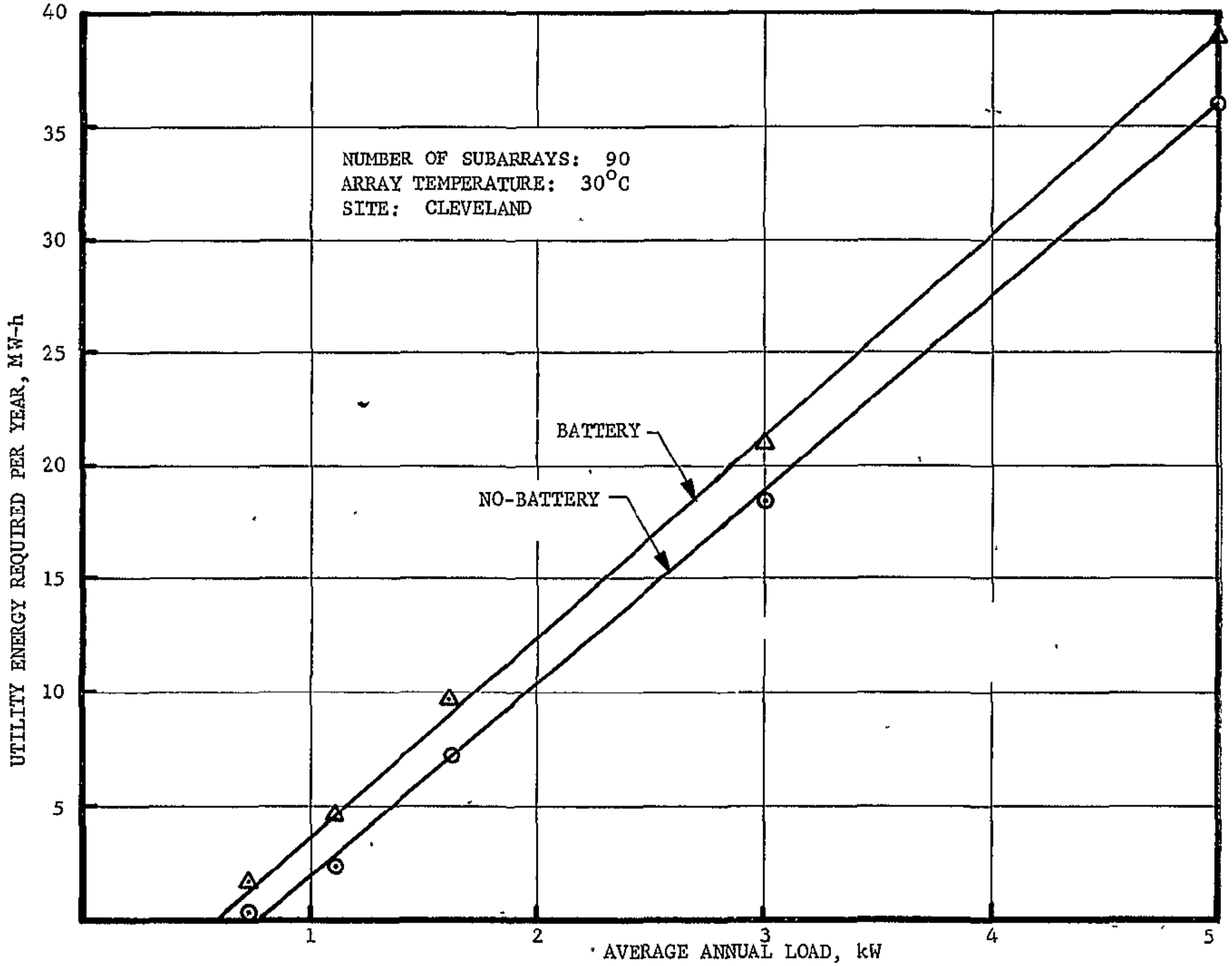


Figure 3-66 Total Annual Utility Energy Required as a Function of Load for Cleveland

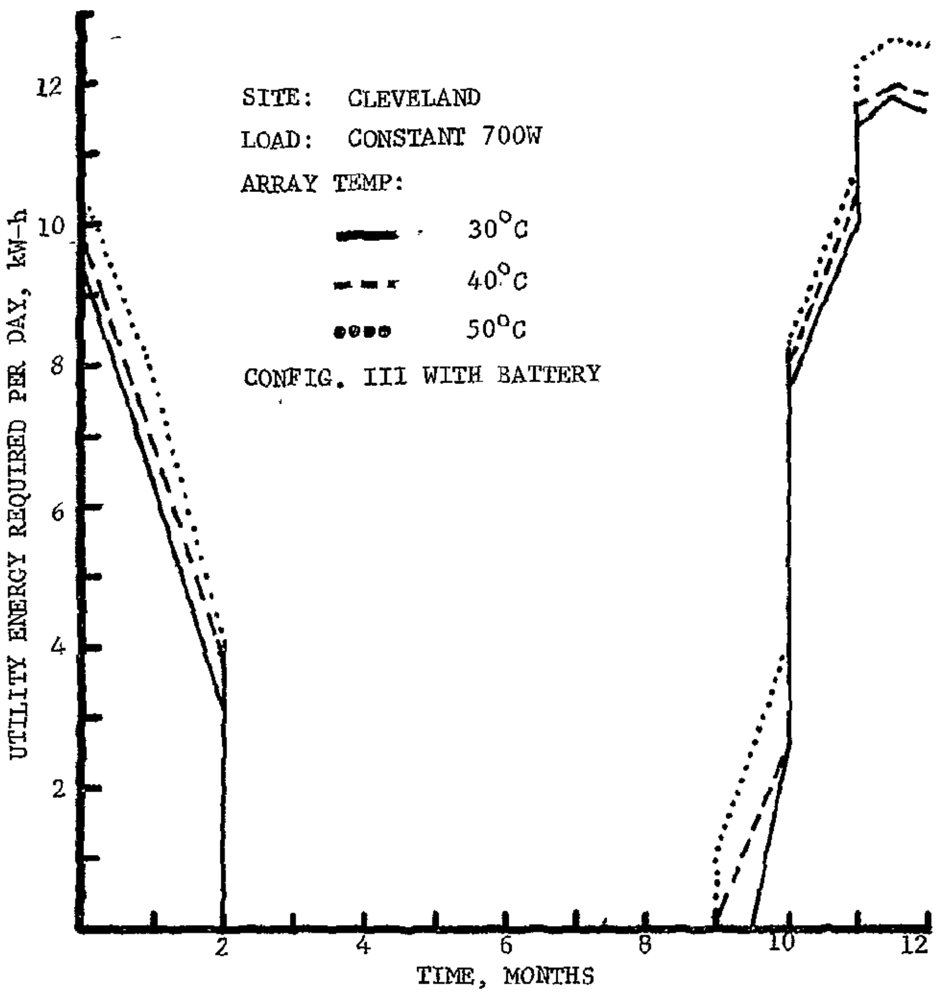


Figure 3-67 Effects of Solar Array Temperature on Utility Energy Required

4.0 CONCEPTUAL DESIGN

4.1 Introduction and Summary

The basic objective of this task was to develop a conceptual design of a 5 to 15 kilowatt Photovoltaic Residential Prototype System Test (PST). The following information are contained in this section:

(1) System, subsystem, and component performance requirements;

(2) Conceptual plan and elevation views (architectural renderings of PST residence);

(3) Description of system and subsystems;

(4) Schematic diagram;

(5) Functional and interface block diagrams;

(6) Dimensions and weights of major subsystems and components;

(7) Data and accuracy;

(8) Operational considerations (maintenance and safety).

The data developed were intended to be sufficient for the preparation of detailed design drawings and specifications and for the selection of components in a subsequent effort to be performed under a separate contract. The basic guidelines were to: (1) use presently available technology, and (2) provide results that are applicable to technology within the next 5 to 10 years. This information should enable subsequent detailed design, construction, and operation of the PST.

The solar cell characteristics, module voltage, and minimum subarray power output specifications were provided by NASA Lewis Research Center (LeRC).

The structure design and architectural renderings of the residential PST were developed by Brooks Waldman Associates, an architectural-engineering firm in Denver. Two concepts, and underground structure and a more conventional above-ground building, were investigated. Drawings of the cross sections and floor plans, including the location of the solar array, battery, and other PST equipment were prepared for the two concepts. The underground structure allows minimum heat loss and maximum environmental control. However, public acceptance of underground living is unknown.

Configuration III, defined in Section 3.0 was selected as the baseline Electrical Power System (EPS) configuration. Three options or variations of Configuration III were developed. These designs, summarized in Table 4-1, were based on technical and cost considerations.

EPS option IIIA operates electrically in parallel with the utility and uses no battery. The interface between the utility grid and the PST power system is controlled by a magnetic amplifier. The solar array is operated at its peak power point by the inverter control unit. Surplus array power is fed back to the utility during the day. The utility supplies all nighttime power.

EPS options IIIB and IIIC both use batteries. They differ by the capacity of the battery and the method of utility connection. EPS option IIIB makes use of utility power at night and during extended periods of low insolation. A "small" battery provides energy for loads exceeding the solar array capability whether due to load peaks or transient periods of reduced insolation. The small battery is intended mainly to reduce the duty cycle of the interface switching unit rather than to store excess array energy available.

EPS option IIIC has the capability of operating without utility support during most environmental conditions. The large battery provides the night energy required and supplements solar array power during the day for peak loads or periods of low insolation. The switching between the PST and utility grid occurs only when the battery is discharged below the specified voltage limit or depth-of-discharge constraint. The duty cycle of the interface switching is low, therefore the PST system operates independent of the utility when PST power is available.

Table 4-1 Defined EPS Options

EPS Options	Solar Array Size, m^2	Battery Capacity	Inverter	Utility Grid Interface
IIIA	133.7	No Battery	Single 10 to 13 kVA Unit	Mag amplifier controlled; operates in parallel with utility and employs power feedback.
IIIB	133.7	Small Battery 5 kW-h (41.66 A-h)	Multiple Inverters	Mag amplifier controlled; Operates in parallel with utility; no feedback.
IIIC	133.7	Large Battery Site Dependent (30 to 42 kW-h), (250 to 350 A-h)	Multiple Inverters	Relay controlled; operates independent of utility when PST power is available; no feedback.

For the purpose of this study, the $133m^2$ solar array defined for the sensitivity analysis was used to facilitate definition of the basic PST power system configuration and the associated options. The main reason for this is that the array size is both site and load dependent. Array sizing criteria were therefore defined for use once a site had been selected. These criteria are presented

The battery for the "small" battery concept (IIIB) is not sized with energy balance consideration. Therefore, the 5 kW-h unit was selected for all five sites. Battery size for the large battery concept (option IIIC) is site dependent; however, 260 A-h battery was sufficient for all sites except Phoenix. Phoenix requires 350 A-h to meet the energy balance and maximize the use of array energy.

The inverter design used for option IIIA is a single unit sized to handle solar array peak power. Utility feedback is employed in this option. Thus the output power of the inverter (during favorable insolation conditions) can be maintained near full load insuring a relatively high efficiency. Options IIIB and IIIC do not use utility feedback, thus multiple inverters of current design are used to maintain a high efficiency and simulate the desired efficiency of projected inverter designs, especially at low load power.

The considerations that gave rise to the three power system options are as follows:

(1) Option IIIA (no battery) was the result of a design analysis that indicated that maximum energy displacement and lowest cost could be realized if power feedback to the utility was employed,

(2) Option IIIB (small battery) is a cost effective, compromise between the no-battery and large-battery concepts relative to the PST. It is based on the sensitivity analysis results which indicated that a higher energy displacement can be achieved by eliminating the battery. The small battery is intended to minimize the switching transients between the utility and the PST.

(3) The large battery option (IIIC) permits maximum independence from the utility and would serve as a tood experiment for the PST to demonstrate an autonomous photovoltaic power system.

Configuration IIIA provides the greatest energy displacement with the advantages of no battery cost and only a single large inverter. The implementation of this concept depends on the utility acceptance of feedback power. The Configuration IIIB has the potential for high energy displacement if the heavy loads such as washing machine, dryer, and air conditioner are programmed to operate on daytime solar array power. The number of current and PST is significantly reduced. The main advantage of Configuration IIIC is that it provides a test bed for operation without utility power for a relatively long period of time. If the cost of the large battery and its associated enclosure and ac charger is prohibitive, the small battery concept can be used with some loss of experimentation capability. Utility interface and some battery tests could still be performed.

The recommended solar array construction is the sawtooth design. The subarrays are placed in rows of 10 consisting of three structures of three rows each. The subarray structure is independent of the building structure. Mechanical adjustments for changing the inclination angle are provided. This design allows for convection, cooling and ease of cleaning, repair, and replacement of the subarrays.

Even with an improvement in inverter technology, it was apparent that multiple inverters are required to maintain high overall PST efficiency. High PST efficiency can be obtained by selecting and operating the inverter at its peak efficiency region. This ensures maximum energy transfer from both the solar array and the battery to the load. The use of multiple inverters is the most cost effective approach when power is not fed to the utility grid. The primary disadvantage is the switching inconvenience that will result.

4.2 Architectural Design of Residential PST

The objective of this task was to develop alternative designs integrating the photovoltaic system into single family residences using conventional construction techniques. These designs were established to identify system limitations and constraints imposed by conventional construction techniques.

Two types of structures were designed: a two-level above ground residence and a single-level below ground residence. Both models are designed to draw on passive use of sun, wind and ground energies.

Concept for Above Ground Structure - The architectural renderings for the two-level structure is shown in Figure 4-1. The main features are as follows:

(1) Solar array structures are on sloping beams;

(2) PST electrical components are housed in a separate structure;

(3) Battery is located in a thermally controlled underground vault;

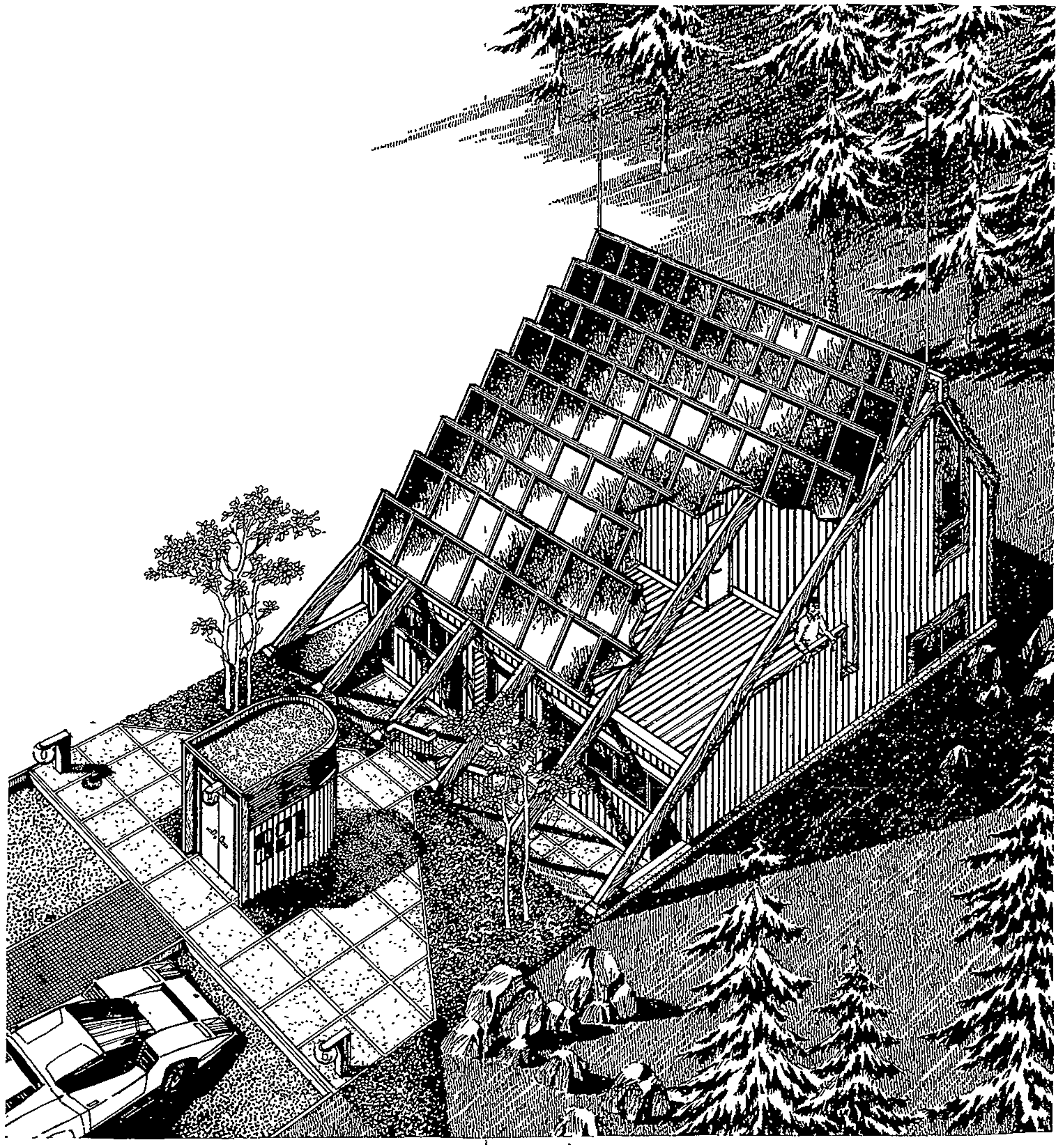
(4) Total glass area is limited to approximately 10 percent of the floor area;

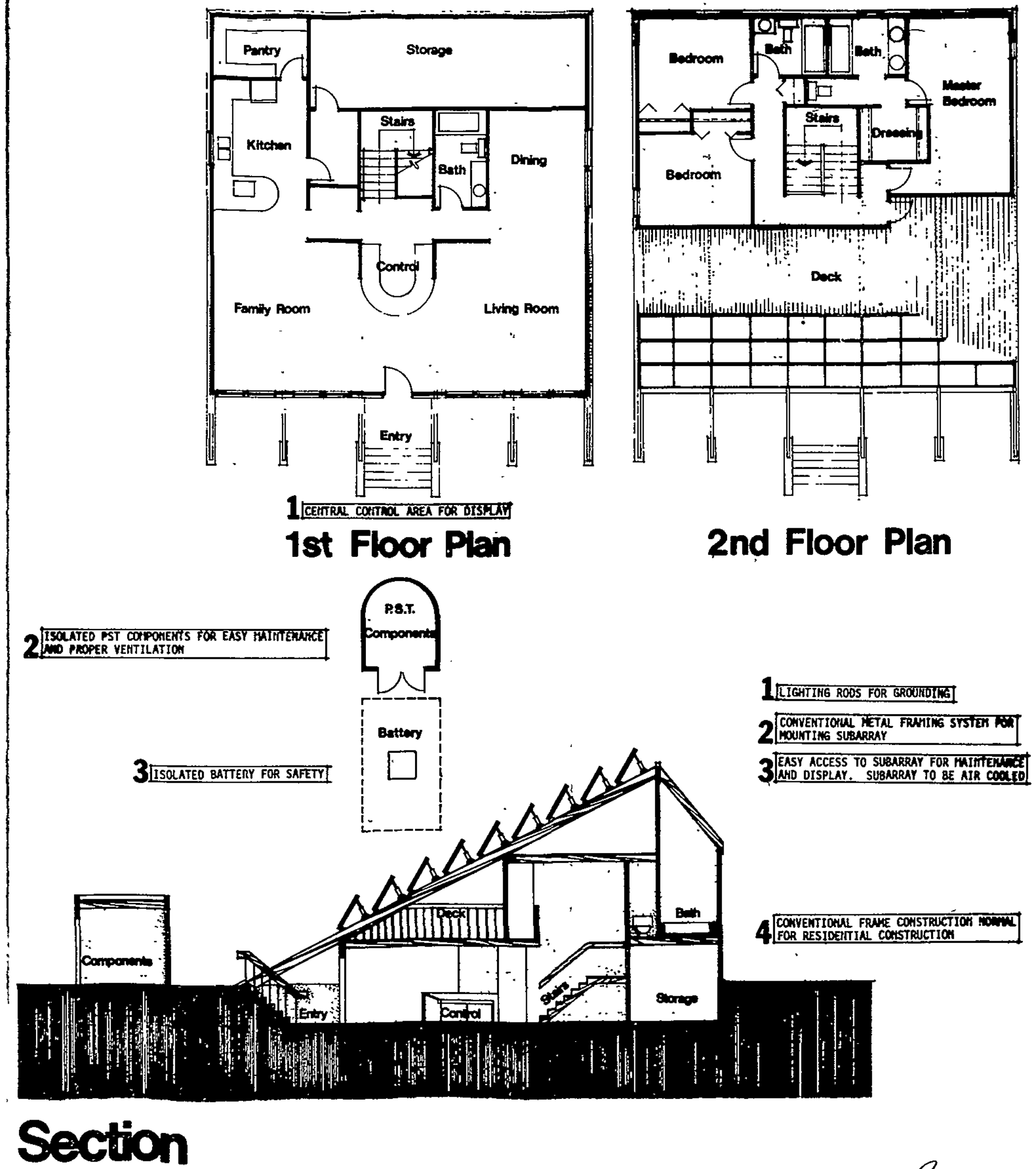
(5) South-facing windows are limited in area and are recessed to receive direct winter solar energy, but are protected from hot summer sun;

(6) Heavily landscaped and depressed south-facing entry courtyard can provide a passive cooling effect during summer months;

(7) West-facing window areas are limited and where necessary would be covered with a reflective surface to resist the penetration of approximately 80 percent of incident summer radiation;

(8) Second floor deck areas are shaded by the solar arrays, but allow air movement through the array and across the deck area to provide a passive cooling effect;





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A *Figure 4-1 Two-Level Above Ground Photovoltaic Residential Structure*

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(9) Building materials were selected for their insulating qualities and construction is designed to permit uninterrupted insulation on all exterior walls from below the floor slab to the roof line.

(10) Exterior walls have 6-inch wood studs with 6 inches of fiber batt insulation. Sheathing material is of wood siding with gypsum board interior wall finish.

(11) Ceiling areas are insulated with 16 inches of fiber batt insulation. Roof areas are framed of wood joist with plywood sheathing over and wood shingles on sloping areas not covered with solar arrays.

(12) The lower level of the model is partially set into the earth to reduce heat loss in winter and to allow cool air movement across landscaped areas to cool the lower level in summer.

(13) Roof mounted wind-powered turbines on the north-sloping roof and air intake vents on the north will increase air movement through the house during summer months providing additional natural cooling. During seasons with cool nights and hot days, air can be drawn into the house at night and early morning. As outside air begins to warm up, the ground level vents and motorized dampers to the wind turbine ventilators can be closed.

The positive features of the above ground residence are: (1) energy conservation features incorporated, (2) easy maintenance of the solar array, (3) easy public acceptance of the structure as a residential house, (4) easy display of PST to the public, (5) capability to adjust array elevation angle for special tests, and demonstrations.

The primary negative features are: (1) the structure is expensive, (2) floor plan lacks flexibility, (3) garage structure is independent of the house.

The basic plan can be modified with the following options:

(1) The floor plan can be revised;

(2) The roof slope can be altered to create a different internal space arrangement;

(3) Building material can be steel, concrete, or others;

(4) Garage structure can be included as part of the house.

Concept for Underground Structure. The architectural rendering for the single-level underground structure is shown in Figure 4-2.

The main features of the structure are as follows:

(1) Single level residence;

(2) Solar array is mounted in three structures;

(3) Solar array structures are independent of building structure;

(4) Mechanical adjustment capability provided for changing solar array elevation angle;

(5) PST electrical components housed in a separate structure;

(6) Battery located in an underground vault;

(7) Concrete walls/prestressed concrete roof structure;

(8) Glass areas are minimized. Where appropriate glass areas face onto sunken courtyards which provide a micro-climate setting for vegetation;

(9) Ground covering and sodding over roof provides equivalent of fiber batt insulation;

(10) Depressed landscaped courtyards offer protection from hot summer sun and provide natural passive cooling of living spaces;

(11) Roof mounted wind-powered turbines and air intake vents can increase natural air circulation,

(12) The addition of a lawn irrigation system can provide the equivalent of a cooling system for living space below;

(13) Economies of construction can be obtained by forming concrete structure over mounded earth and then excavating mound from below concrete structure and filling over and landscaping it;

(14) Exterior finish materials are eliminated further reducing construction cost.

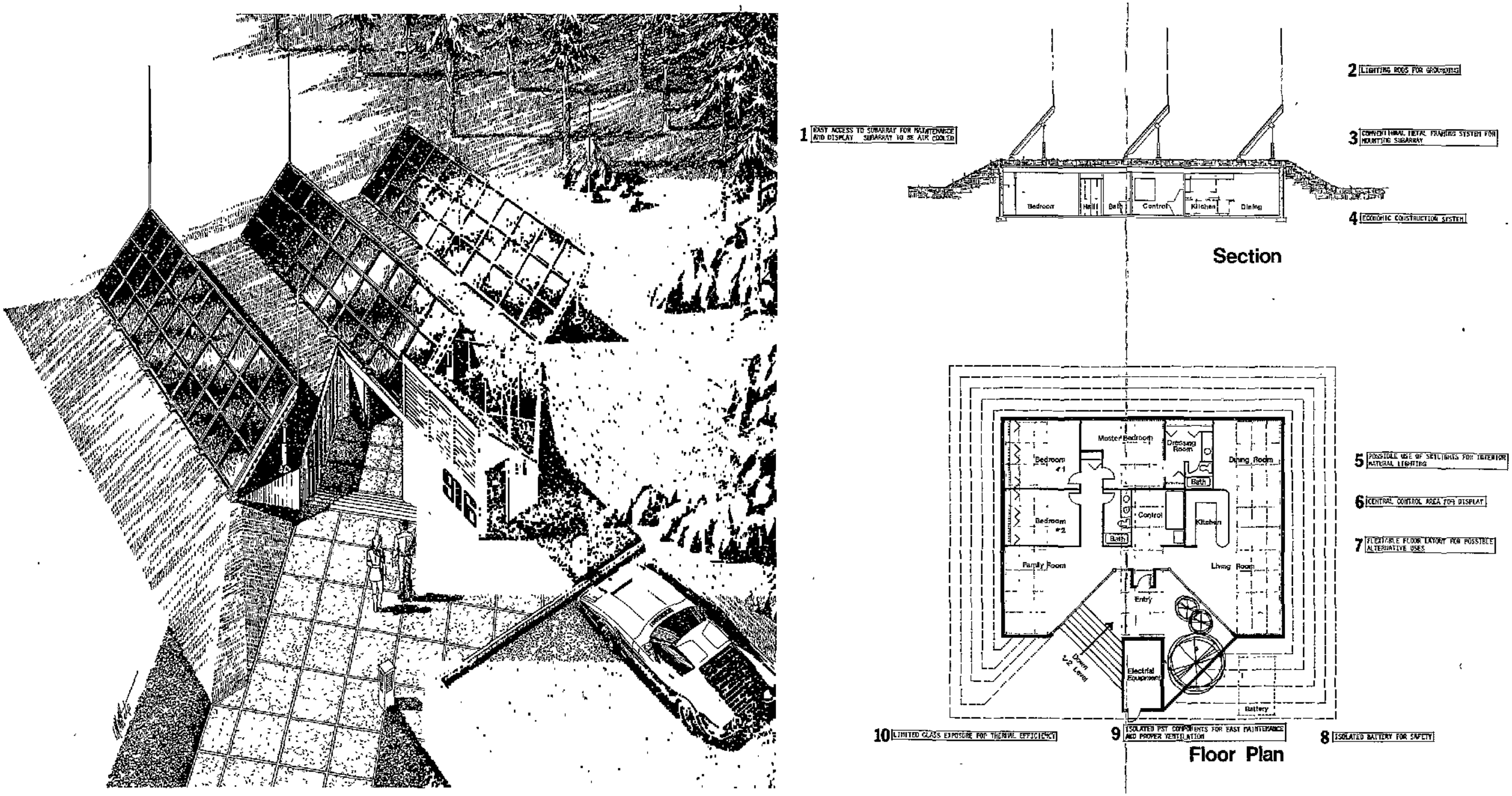

Figure 4-2 Single Level Underground Photovoltaic Residential Structure

A

B

The positive features of the underground structure are: (1) easy maintenance of solar array; (2) maximum residential thermal efficiency due to underground characteristics; (3) capability to adjust array elevation angle for special tests and demonstrations; (4) easy display of PST to public.

The negative features of the underground structure are: (1) public acceptance of underground living is not known; (2) vandalism problems due to easy access; (3) garage structure must be independent of the house.

The primary alternate option for the underground residence is that the entire structure may be placed above ground as a single story structure.

4.3 Electrical Power System Performance Requirements and Description

4.3.1 Performance Requirements

The equipment selected for the PST will permit testing each of the PST configurations defined above. The equipment is sized and the system configuration selected to meet the following performance requirements:

(1) Convert solar radiation into dc and ac electrical energy suitable for residential and/or utility use,

(2) Provide energy storage to supply peak loads and nighttime loads,

(3) Operate electrically in parallel with, or isolated from, the utility grid;

(4) Operate with or without energy storage;

(5) Supply peak ac loads of up to 13 kilovolt-ampere;

(6) Provide for maximum use of solar array energy;

(7) Supply an average daily bus load of 1000 watts under the following conditions:

(a) Minimum sunlight duration and average annual insolation condition for the geographical site;

(b) Energy balance between the solar array and battery (if included) or load;

(c) Specified maximum battery depth-of-discharge.

The baseline subsystem configuration is shown in Figure 4-3. This arrangement permits operating the system in each of the three selected configurations via the control and display system.

4.3.2 Battery

The battery provides a supplemental energy source for the PST during the daytime and, for Configuration IIIC, the primary energy source for the nighttime energy requirements. The daytime energy is required during periods of low solar irradiance and periods of peak power requirements. To meet the requirements of the PST, the battery performance requirements defined in Table 4-2 were identified.

Table 4-2 Battery Performance Requirements

Seven Year Life
2500 Charge/Discharge Cycles
Capacity of 18,000 watt-hours at the 10-hour Rate
Minimum Discharge Voltage of 105 Vdc
Maximum Charge Voltage of 144 Vdc
Maximum Discharge Current of 150 amperes
Maximum Depth-of-Discharge of 70%

The battery design selected to meet the requirements is summarized in Table 4-3.

Table 4-3 Battery Design Description

Characteristic	Requirement
Type	Antimony Lead-Acid Cells
Quantity	60 - Series Connected
Capacity-Rated	264 ampere-hours at the 10-hour Rate
Capacity-Deliverable	21,511 watt-hours at 70% Depth-of-Discharge, 10-hour Rate and Average Discharge Voltage of 116.4 Vdc
Life	Seven Years and 2500 Cycles
Charging Voltage	144 Vdc
Discharge Voltage	116.4 Vdc Average; 105 Vdc Minimum
Weight	1818 kg
Volume	3.6 m^3

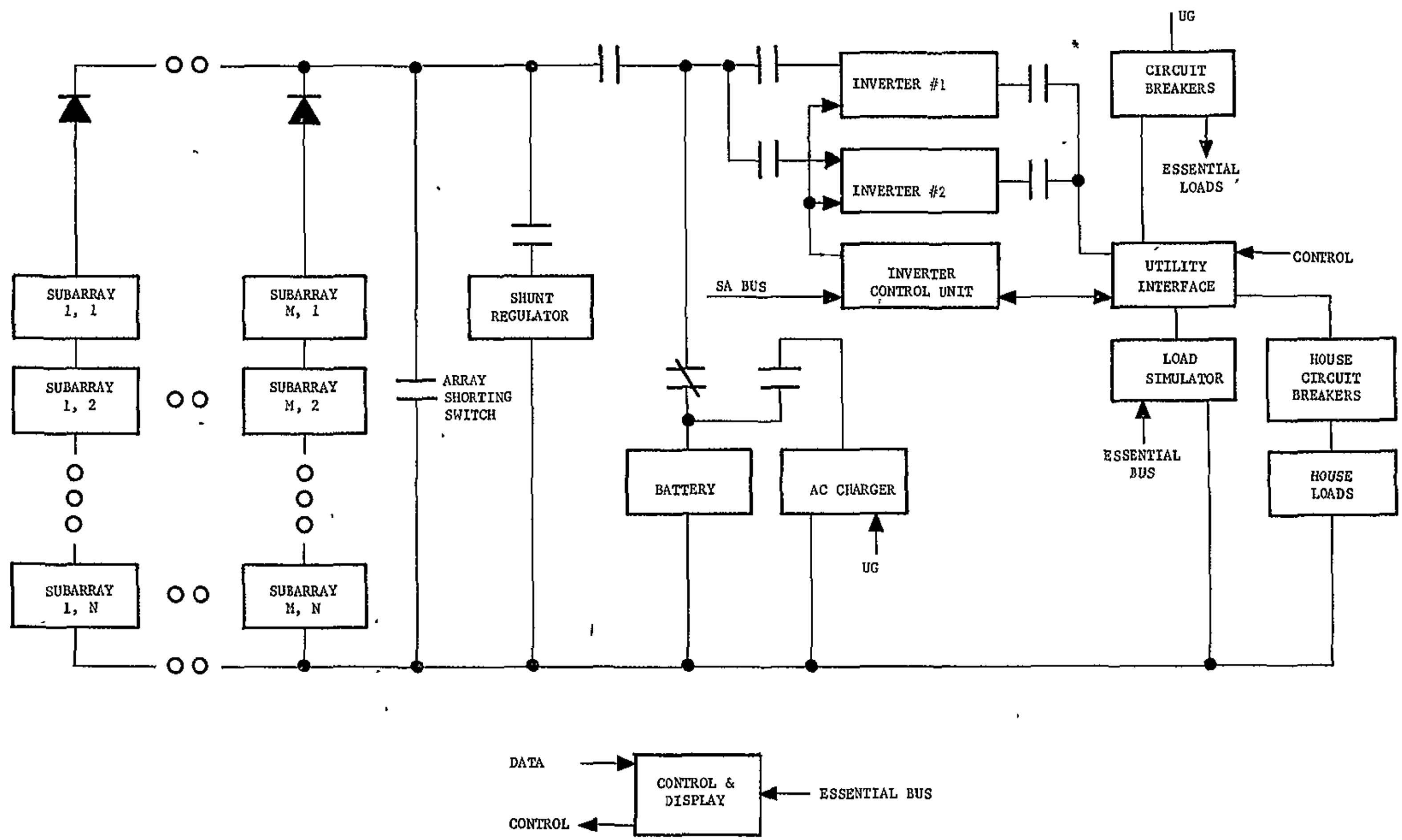

Figure 4-3 Functional Block Diagram of Baseline PST Power System

4.3.3 Inverter

The inverter provides the conversion from the solar array or battery dc power to ac power at 115/230 Vac single phase (60 Hz). The recommended performance requirements for the inverter are shown in Table 4-4.

A survey of several inverter manufacturers shows that units meeting all of the requirements are not available as off-the-shelf units (see table 4-50). Inverter efficiency at low loads is the most serious problem. To overcome the low efficiency, a minimum of two inverters are recommended for use in the PST system.

A small inverter supplies the power requirements up to one kilovolt-ampere. This unit is used in configurations not allowing PST power to be fed to the utility grid. A large, 13 kilovolt-ampere inverter provides the capability to meet maximum system loads and is used exclusively in Configuration IIIA to supply all surplus energy to the utility grid. Using a third inverter of five kilovolt-ampere rating, a reasonably high overall PST efficiency can be achieved.

For Configuration IIIA, control of the inverters is handled by the inverter control unit (ICU). On/off control of the inverter is performed by the ICU. The ICU also provides synchronization of the units before transfer.

Heat dissipation for the inverter will be required. This heat may be removed with forced air cooling or by a water loop. Because of the quantity of heat available, the water loop might be economical. With a 75 to 80% efficient inverter at the average system load of one kilowatt, 200 to 250 watts of heat must be removed. This heat could be used for space heating in the winter, heating domestic hot water, etc.

4.3.4 Inverter Control Unit (ICU)

The ICU permits operation of the inverter in parallel with the utility while maintaining control of the inverter loading. Figure 4-4 is the functional block diagram for a system which permits operating an off-the-shelf inverter in parallel with the utility grid.

The inverter output is isolated from the utility grid by an inductive isolation network, designed to preclude inverter overloading, and to allow the inverter to sink output power to the utility grid. The solar array peak power tracker furnishes an analog signal to

Table 4-4 Inverter Performance Requirements

Characteristic	Requirements
Input Voltage Range	105 to 140 Vdc
Output Voltage	115/230 volts, Three Wire, Single Phase, 60 Hz
Output Power	13 kVA full load at 0.85 Lagging Power Factor
Power Factor Range	0.70 Lagging to Unity to 0.95 Leading
Overload Rating	150%, two sec Minimum
Short Circuit Output Rating	200% minimum full load rms current rating, two sec minimum (to assure fault current capability to operate circuit breakers and/or fuses).
Output Voltage Regulation	115 Vac rms ± 1%, no load to full load, power factor unity to 0.85 lagging; 115 Vac rms ± 10% including transients, no load to 150% overload, power factor unity to 0.75 lagging.
Frequency Stability	60 Hz ± 0.25% free running, with frequency and phase-lock synchronizing to utility power
Total Harmonic Distortion	5% maximum total, no load to full load, with 2% or less in any individual harmonic
Inverter Efficiency	25% full load - 75% 50% full load - 80% 75% full load - 85% Full load - 90%
Overload Protection	Current limit (2 sec) at 150% to 200% overload current, followed by automatic output interruption
Internal Fault Protection	Sensing and shutdown, including interruption of input and output power lines
Construction	In accordance with applicable National Electrical Manufacturers Association (NEMA) standards and National Electric Code (NEC)
Operating Environment	0 to 40°C (32 to 104°F)
Capability for Parallel Operation with Utility Three-Wire Service	Desirable
Selected MTBF	10,000 to 20,000 hours

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Table 4-5 Partial List of Available Single Phase, 115/230 Vac, Three-Wire, 60 Hz Static Inverters

MFR/Model	Output, kVA	Input Voltage, Vdc	Volume, ft^3	Weight, lb	Approximate Cost, $	Primary Design Application	Capability for Parallel with UG	Typical Efficiency % of Full Load Rating 25	50	75	100	Availability	NEMA or NEC Compliance
ELGAR	1 to 20	105 to 140											
INV-502	5.0	105 to 140	31	1000	5,450.00	UPS	No	—	—	—	80	Off Shelf	Yes
INV-103	10.0	105 to 140	38	1400	9,950.00	UPS	No	—	—	—	80	Off Shelf	Yes
INV-203	20.0	105 to 140	60	2000	13,500.00	UPS	No	—	—	—	80	Off Shelf	Yes
NOVA	1 to 3	22 to 350											
1K60-150	1.0	105 to 150	1.1	100	1,360.00	UPS	No	—	—	—	75	Off Shelf	Yes
2K60-150	2.0	105 to 150	2.1	200	2,140.00	UPS	No	—	—	—	75	Off Shelf	Yes
3K60-150	3.0	105 to 150	3.6	325	3,700.00	UPS	No	—	—	—	75	Off Shelf	Yes
ABACUS	0.5 to 6.0	48 to 140											
423-4	2.0	100 to 140	2.7	90	3,000.00	UPS	No	—	—	—	80	Off Shelf	Yes
443-4	4.0	100 to 140	5.0	210	5,600.00	UPS	No	—	—	—	80	Off Shelf	Yes
463-4	6.0	100 to 140	16	390	7,900.00	UPS	No	—	—	—	80	Off Shelf	Yes
TOPAZ	0.2 to 3.0*	12 to 125											
1000 GZ	1.0	105 to 140	1.0	95		UPS	No	—	—	—	75	Off Shelf	Yes
2000 GZ	2.0	24 to 32†	2.0	190		UPS	No	—	—	—	75	Off Shelf	Yes
3000 GZ	3.0	24 to 32†	3.0	285		UPS	No	—	—	—	75	Off Shelf	Yes
SOLA	1.2 to 10												
26-1040	10.0	120 Nom	16	1700	10,252.00	UPS	No				80	Off Shelf	Yes
DELTEC	0.3 to 10	120 Nom											
DI-1203	1.2	125 Nom	1.4	110	1,090.00	UPS	No					Off Shelf	Yes
DI-1803	1.8	125 Nom	2.6	195	1,740.00	UPS	No					Off Shelf	Yes
DI-3003	3.0	125 Nom	6.2	475	2,995.00	UPS	No					Off Shelf	Yes
DI-5003	5.0	125 Nom	6.2	525	3,450.00	UPS	No					Off Shelf	Yes
DI-10003	10.0	125 Nom	44	1050	6,510.00	UPS	No					Off Shelf	Yes
Westinghouse								(Projected from 1600W Tare Loss)					
PC-11	13.0	100 to 185	20.4	1000	13,000 (EST)	Fuel Cell	Yes	65	75	80	85	Unknown	Unknown
PC-16	13.0	100 to 200	10.3	400		Fuel Cell	Yes	75	80	85	90	Unknown	Unknown

*10 kVA unit reportedly manufactured.
†125 Vdc nominal input voltage not available, all models.

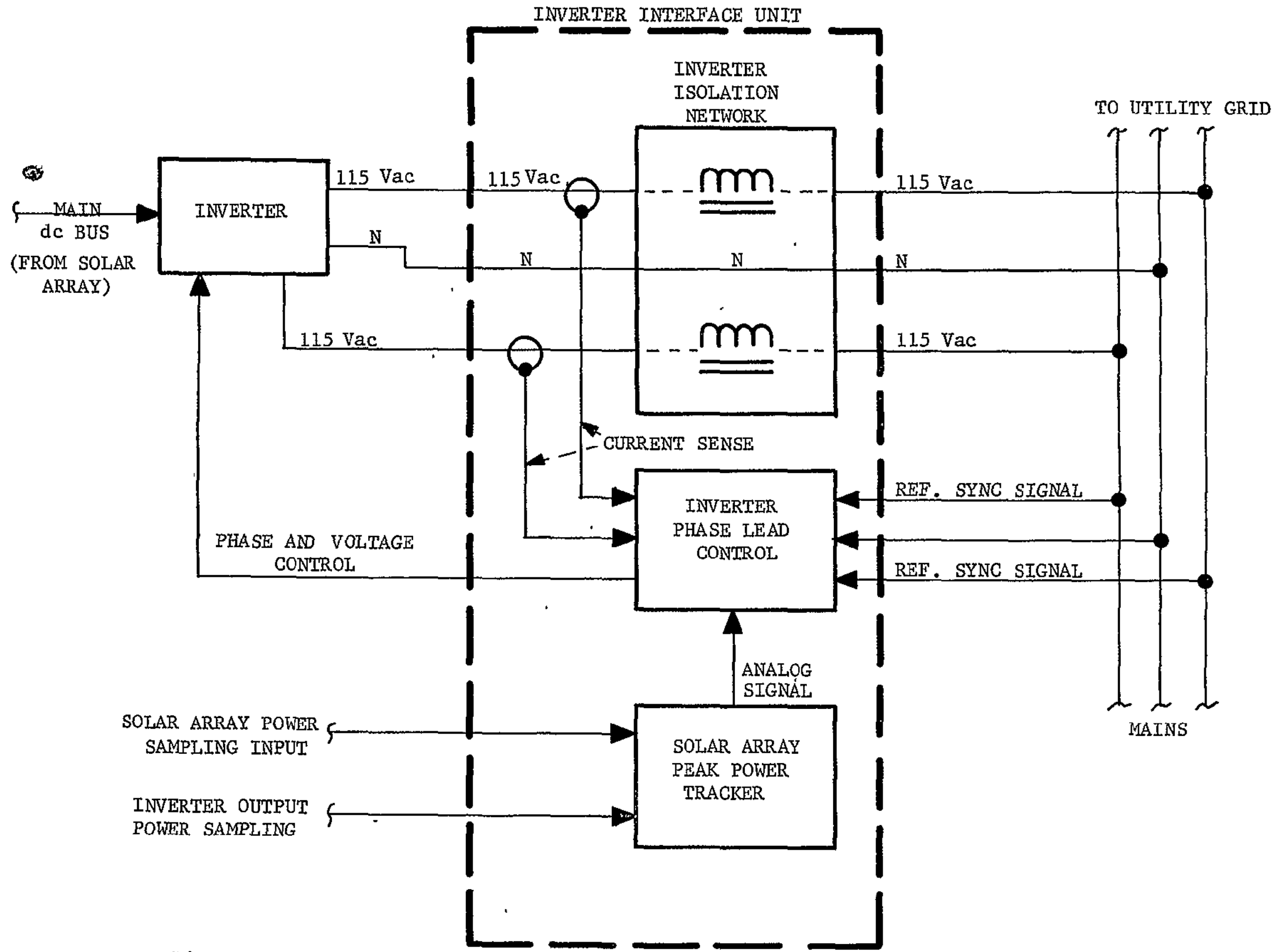

Figure 4-4 Functional Block Diagram Showing Inverter Interface Unit for Operating an Off-the-Shelf Inverter in Parallel with Utility Grid

control the phase of inverter output such that the solar array is operated at its peak power point continuously.

The peak power tracker output then controls the inverter phase such that solar array peak available power equals the solar array bus power with the following constraints: (1) inverter outputs are never overloaded, and (2) utility power is present (e.g., the utility grid has not lost integrity). This approach allows the inverter to be power-output-coupled to the utility grid, using it as an energy sink.

There may be situations when a direct tie with the utility grid is desirable with the constraint that no power is fed back onto the utility grid. For this configuration (see fig. 4-5), the inverter supplies PST power at all times except when:

(1) Inverter output power demand exceeds the maximum safe operating level for the inverter;

(2) Inverter output voltage degrades because of reduced solar array bus voltage (due to low insolation, etc).

At that point, the inductor cores in the magnetic amplifier isolator are saturated by bias current from the magnetic amplifier control unit and a direct utility grid tie is provided. This enables the excess demand power to be drawn from the utility grid.

The configuration shown in Figure 4-6 combines the previous systems to provide solar array peak power tracking, additional utility grid power during intervals of excess demand, and to inhibit power flow to the utility grid. Because of the inhibited power flow back to the utility grid, this system should be operated with energy storage to permit energy to be stored during peak solar array output and low power demand. This system requires that the loads be nearly balanced.

For widely unbalanced inverter output loading, a modification is necessary to control the two inverter outputs separately. Because three-wire, single-phase inverters do not generally have the capability for individual phase-shifting control for each output, two separate inverters are foreseen. Each inverter will have a reduced kilovolt-ampere requirement and a two-wire, single-phase output. Each line voltage will have independent phase control. The system shown in Figure 4-7 is modified for unbalanced loads as follows:

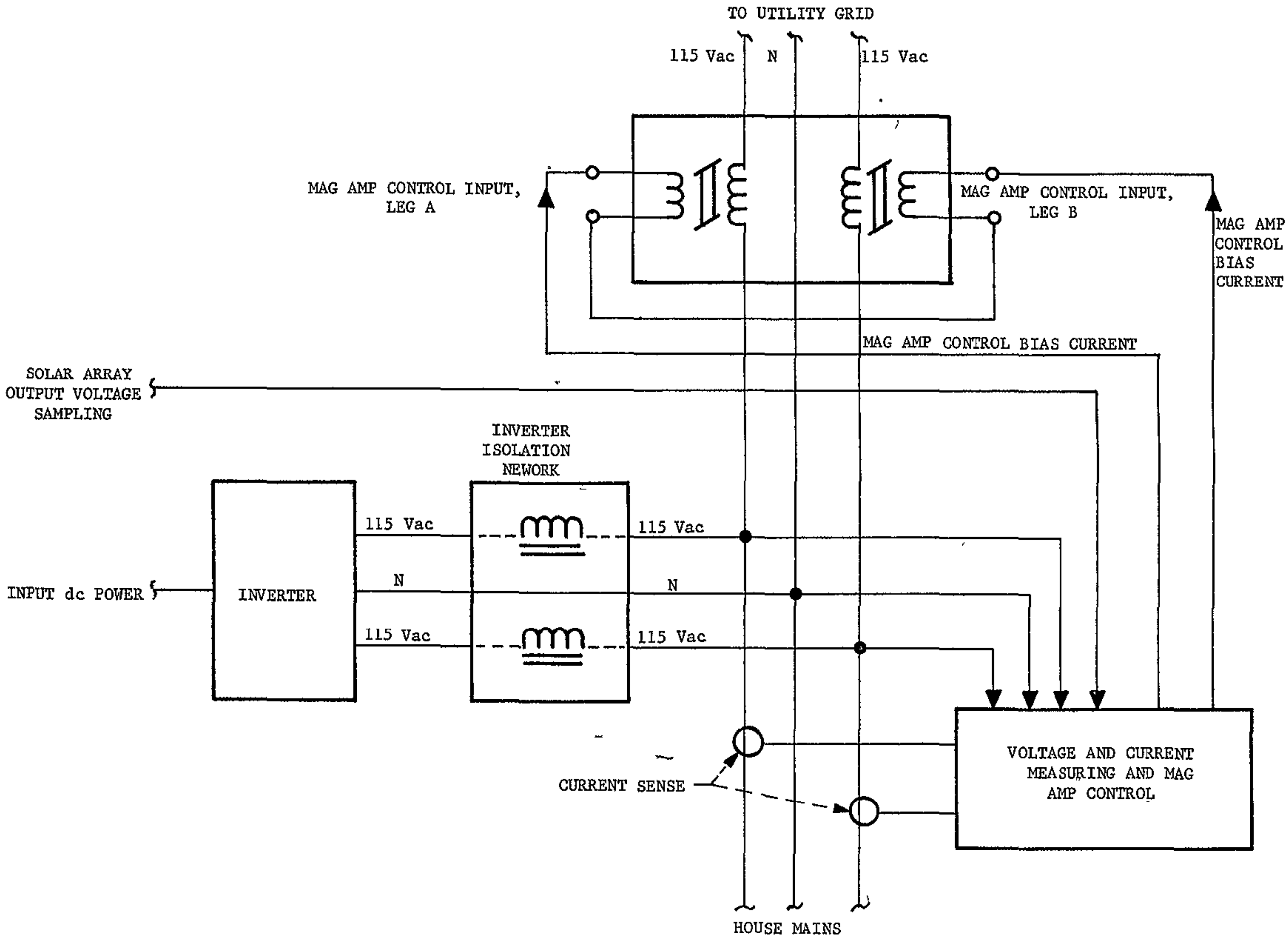

Figure 4-5 Functional Block Diagram Showing Inverter Utility Interface Unit Parallel - Tie Operation with Constraint that No Power Is to Be Fed Back to Utility Grid

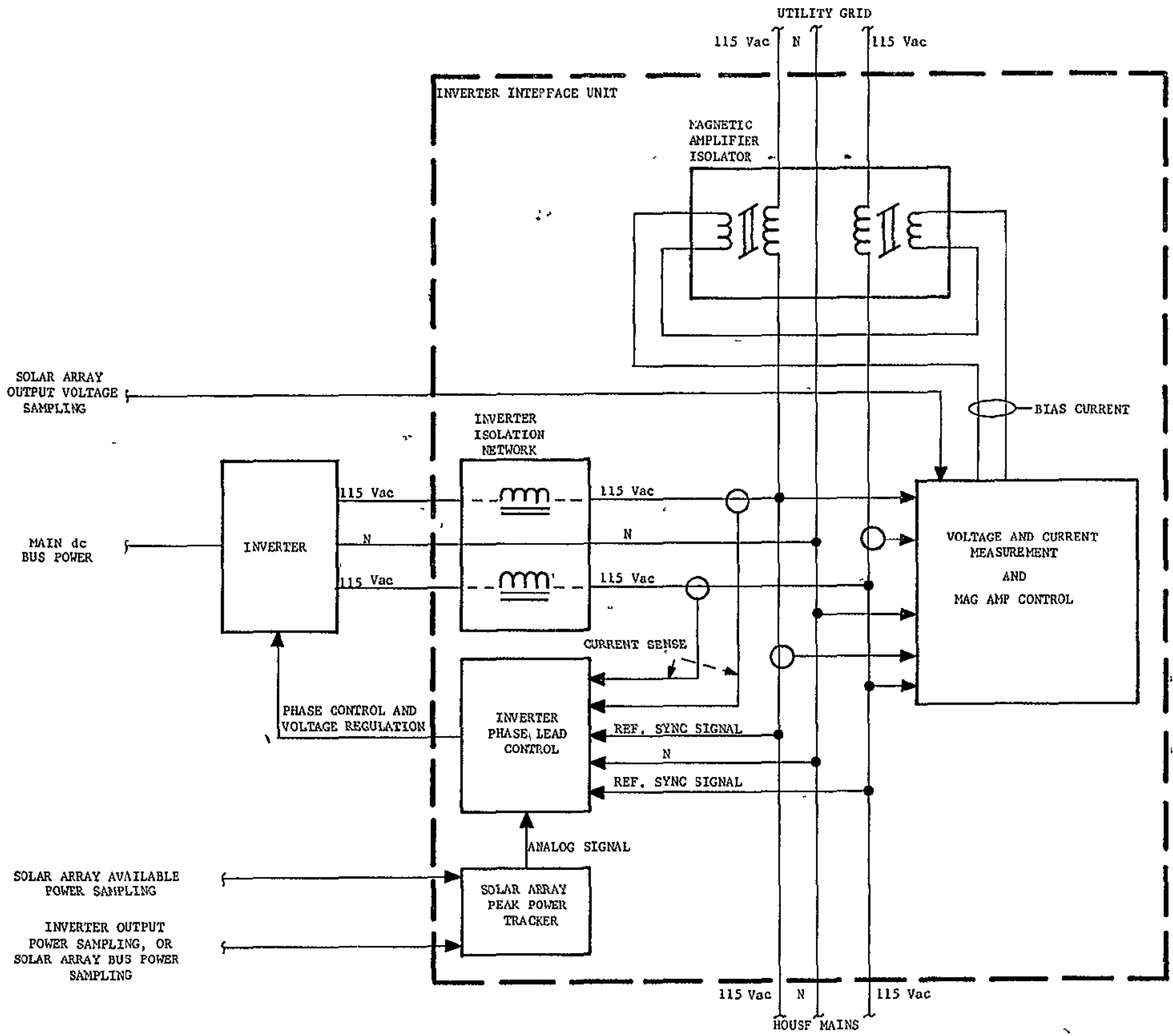

Figure 4-6 Functional Diagram Showing Combined Aspects of Figures 4-4 and 4-5

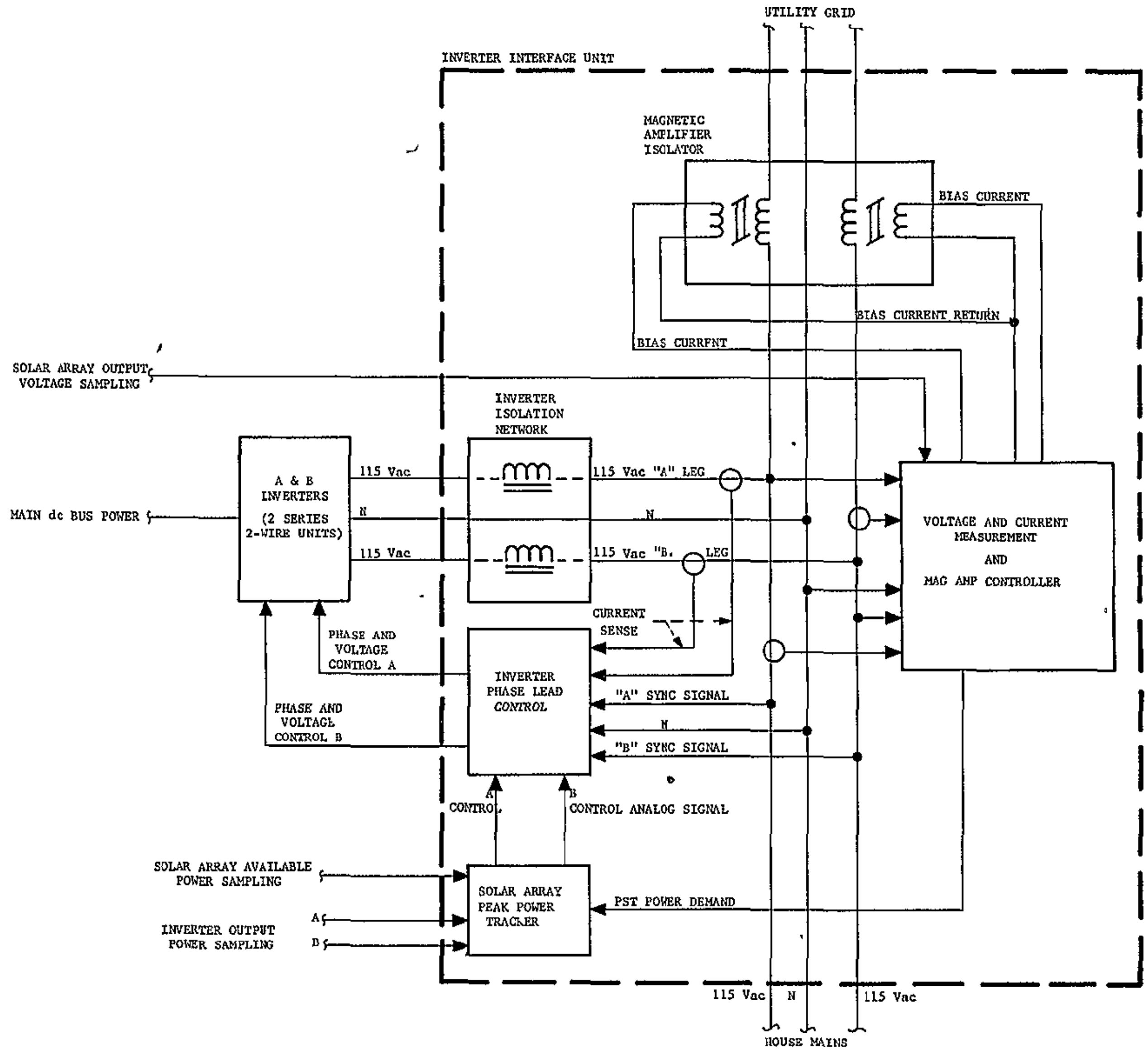

Figure 4-7 Functional Diagram Showing Inverter Interface Unit Modified for Unbalanced-Load Operation

(1) The single inverter is replaced with two, 115-Vac two-wire inverters (A and B);

(2) Independent phase controls are derived from the phase lead control which in turn drives master "A-leg" and "B-leg" synchronization and phase reference signals from the PST mains (utility grid in case of parallel operation),

(3) The solar array peak power tracker now incorporates additional logic to monitor:

   (a) PST power demand;

   (b) Inverter A&B power output;

   (c) Peak available solar array power.

(4) Logic enabling necessary decision-making (within the peak power tracker) to:

   (a) Peak power track the solar array during intervals where power is also drawn from the utility grid;

   (b) Maintain optimum phase shift of each inverter with respect to the utility grid.

4.3.5 Shunt Regulator/Auxiliary Load

The shunt regulator and auxiliary load provide a means of clamping (limiting) the upper array voltage, and using the available solar array power. During battery charging the maximum bus voltage is limited by the battery. After the battery reaches full charge, and it is disconnected from the bus, the inverter is subject to damage from high voltages at light loads due to the solar array output voltage-current characteristic (fig. 4-8). To maintain the solar array at or below the maximum inverter input voltage, a shunt regulator is used with the power dissipated in a auxiliary load.

A functional block diagram of the shunt regulator/auxiliary load employed to control the solar array output power in the PST is shown in Figure 4-9. The shunt regulator consists of 15 sequences that are switched at one time depending upon the load conditions. The 15-sequence shunt regulator is designed for a power subsystem which employs a particular size of solar array and battery and uses an inverter which operates with the input voltage of 105 volts to 200 volts dc.

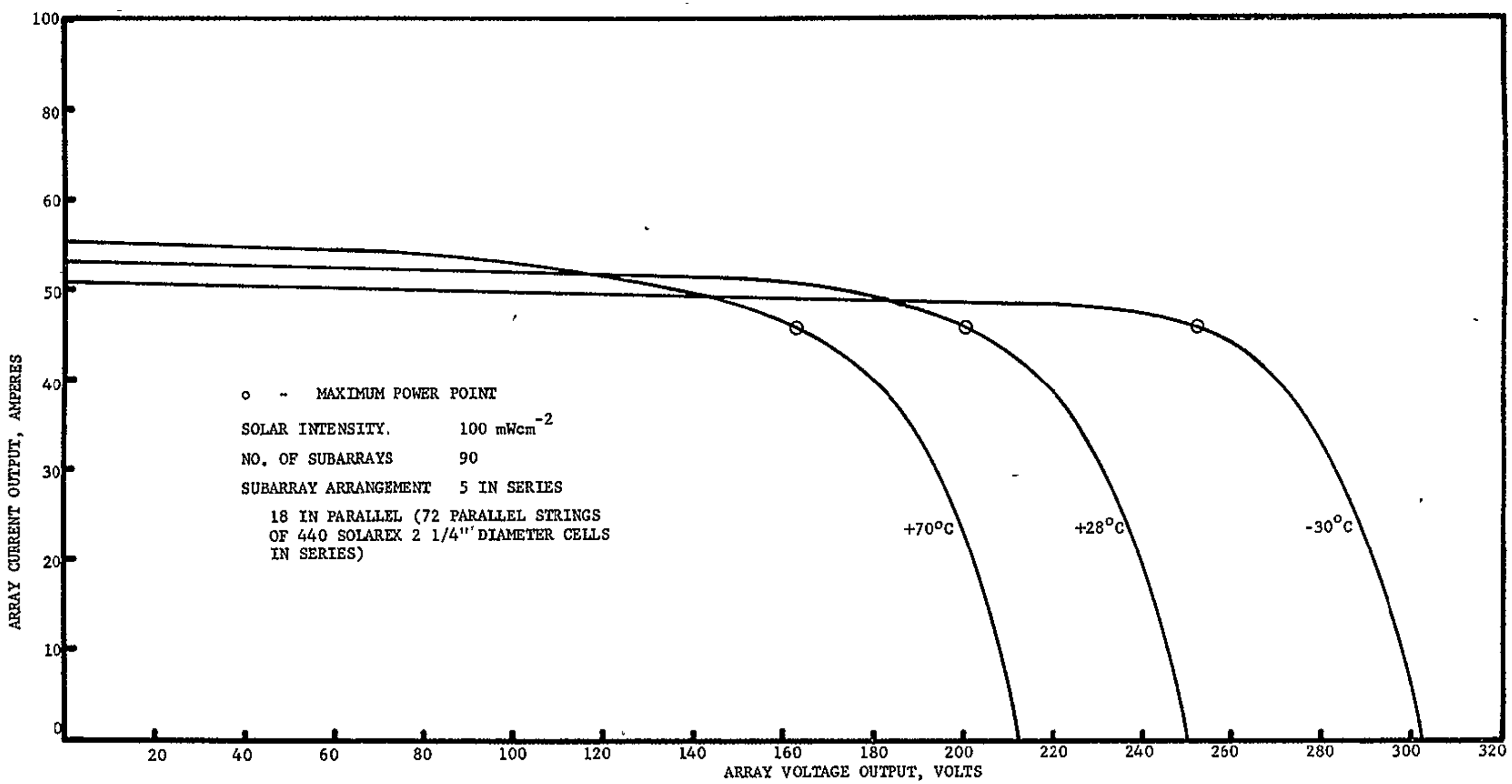

Figure 4-8 IV Characteristics - PST Baseline Solar Array Configuration

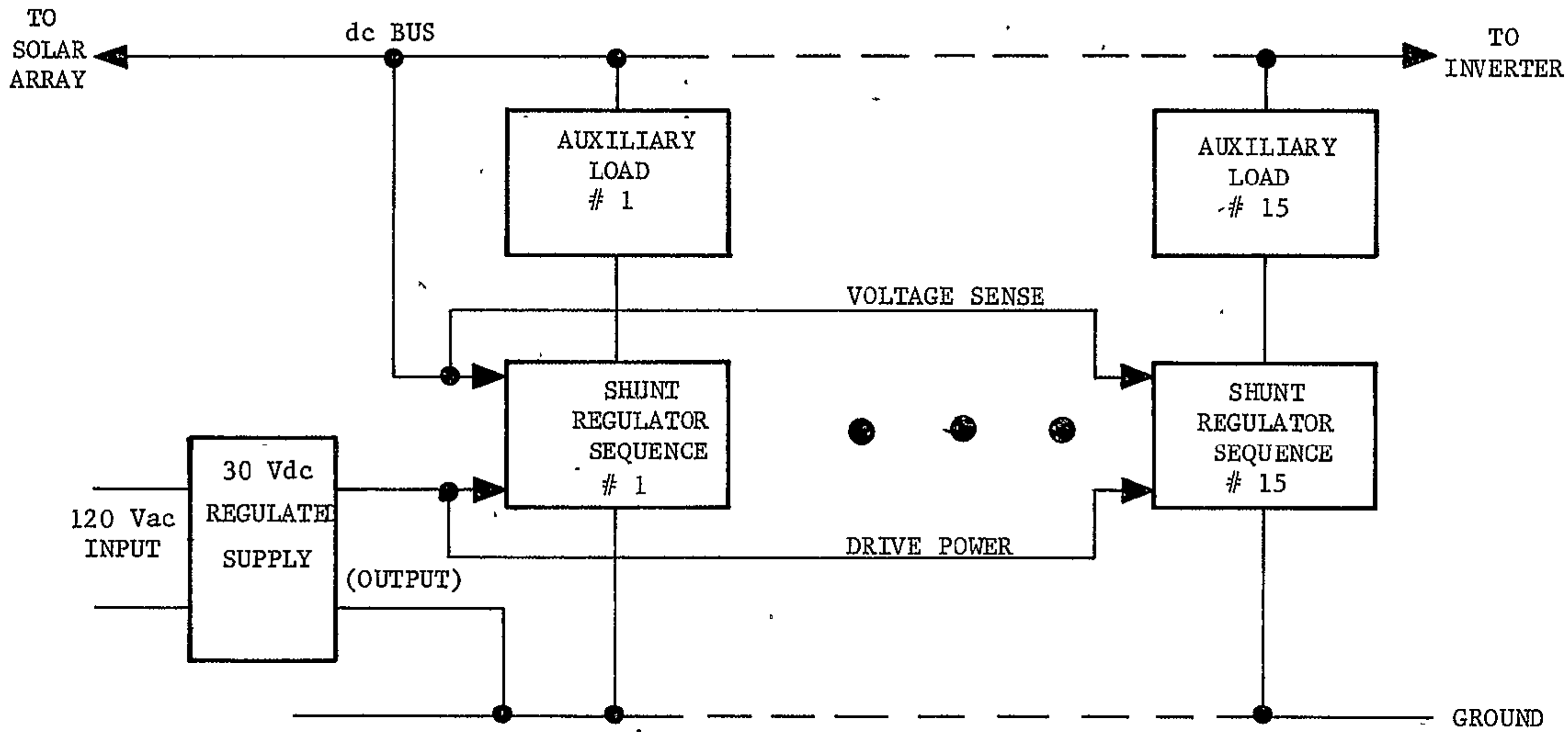

Figure 4-9 Shunt Regulator/Auxiliary Load Functional Block Diagram

The shunt regulator/auxiliary load circuit diagram for a typical sequence is shown in Figure 4-10. The regulator voltage-current transfer characteristic is shown in Figure 4-11. The solar array is sized so that at the maximum solar array operating temperature, maximum solar intensity and the maximum load, the array operates in the constant current region near the maximum power point. In the case of the PST, all power available from the solar array below 150 Vdc goes either to the load at the output of the inverter, or to charge the battery at the input side of the inverter. Thus the dc voltage at the inverter input is controlled by the battery below 150 volts. Above 150 volts, where the battery is fully charged and must be disconnected from the dc bus for safety reasons, the bus is no longer controlled by the battery. At this point, if the load at the inverter output is reduced, the solar array no longer operates near the maximum power point and its output voltage starts rising. The shunt regulator sequence control circuitry is designed to sense this voltage, and to fully turn on the required number of sequences. This diverts the excess power to the auxiliary loads (connected in series with the shunt switch as shown in Figure 4-10 and forcing the solar array to operate near the maximum power point.

The size of a particular sequence is determined by the load handling capability of the auxiliary load and the power dissipation limitation of the shunt transistor. The number of sequences is determined so that when all the shunt sequences are on (no load at the output of the inverter) the solar array operates at the maximum power point ensuring full use of the maximum power available from the solar array in the auxiliary loads. The shunt regulator sequence turn-on threshold voltages and corresponding auxiliary loads are shown in Table 4-6. It should be noted from the table, that the last sequence (sequence No. 15) turns on at the solar array output voltage corresponding to the maximum power point when the array is operating at the maximum temperature and intensity.

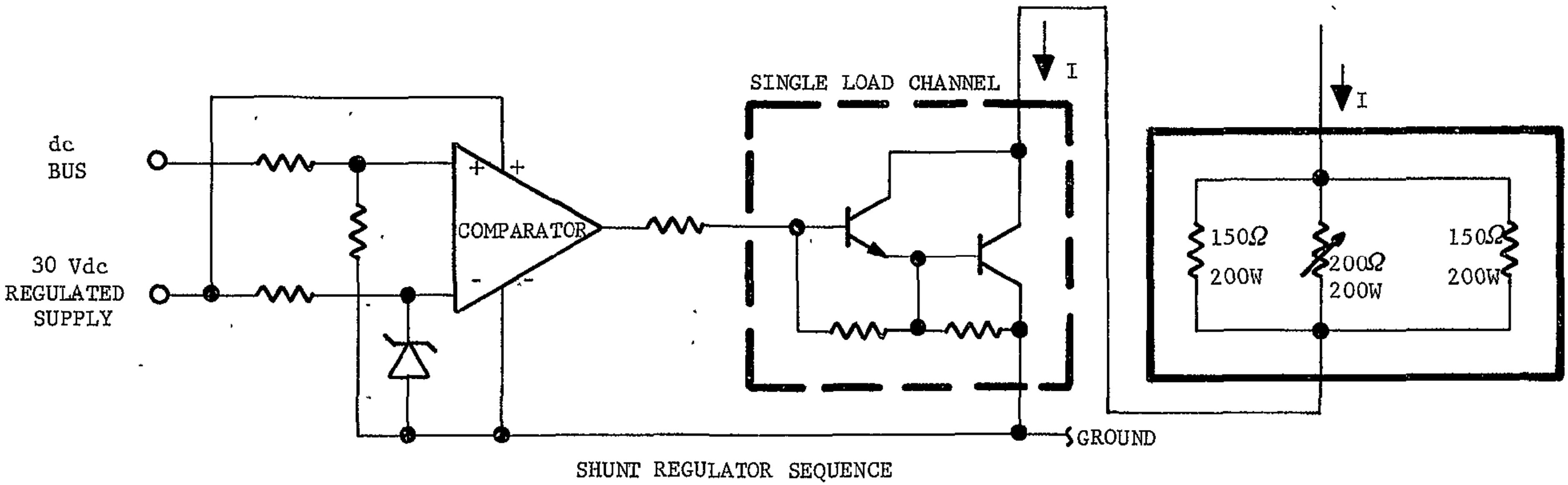

Figure 4-10 Typical Shunt Regulator Sequence and Auxiliary Load Schematic

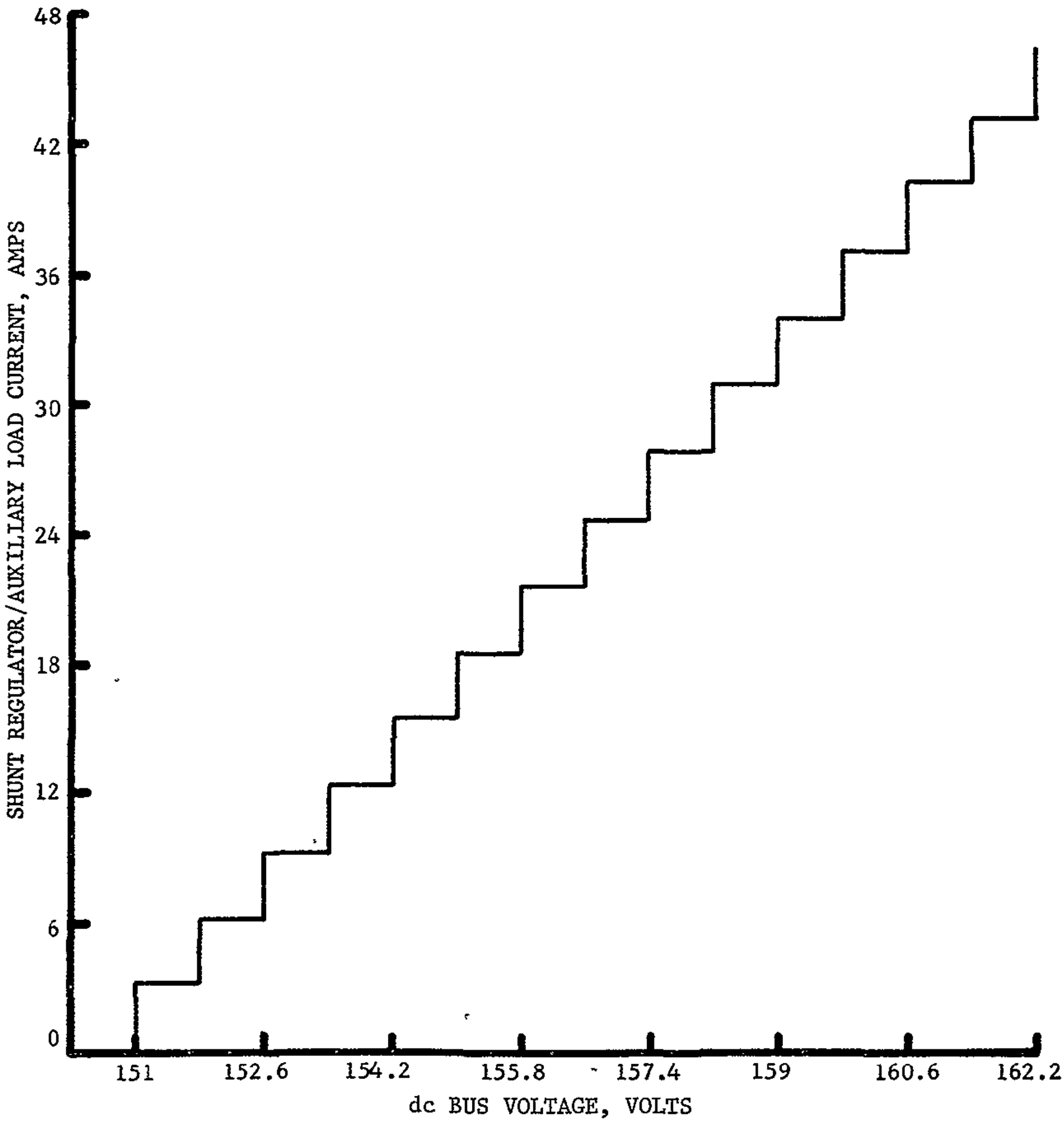

Figure 4-11 Shunt Regulator Transfer Characteristic

Table 4-6 Shunt Regulator Turn-On Threshold Voltages

Shunt Regulator Seq. No.	Turn-On Threshold Voltage, Bus Voltage	Auxiliary Load* Resistor
1	151.0 V	48.89
2	151.8	49.15
3	152.6	49.7
4	153.4	49.97
5	154.2	50.23
6	155.0	50.49
7	155.8	50.75
8	156.6	51.0
9	157.4	51.27
10	158.2	51.53
11	159.0	51.79
12	159.8	52.05
13	160.6	52.31
14	161.4	52.57
15	162.2	52.83

*Auxiliary Load Resistor

$$= \frac{V_{BUS} - V_{SAT}\text{ (SHUNT TRANSISTOR)}}{I_{SHUNT}}$$

$V_{SAT} \approx 0.9$ VOLT (FOR TRANSISTOR DTS 4061)

No. of Parallel Stages = 15

Shunt Regulator Current for Stage = 3.07

The design approach employed here to regulate the dc bus is very versatile. It can be easily employed to accommodate any size of auxiliary load, inverter, solar array and its operating temperature by changing the number of sequences and/or sequence turn on threshold voltages.

4.3.6 AC Battery Charger

The charger is used to permit limited system checkout and to charge the battery direct from the utility. This capability permits recharging quickly after or during periods of low insolation, high battery drain, or battery maintenance or test.

The ac battery charger requirements are as follows:

(1) Charging a battery at any voltage between 132 and 155 Vdc in the constant voltage mode;

(2) Charging at rates of up to 40 amperes;

(3) Operating from normal residential power of 120/240 Vac, single phase.

Commercial units are available which will meet these performance requirements. The units available from one manufacturer which are in the range of these requirements are shown in Table 4-7.

Table 4-7 Characteristics of Commercially Available ac Charger

Model Number	Input Voltage, Vac	Output Voltage Range, V	Output Current, A*	Weight, lb	Cost, $
SCB-120-30	120† or 240	132 to 144	30 Maximum	190	891.8
SCB-120-40	240	132 to 144	40	297	1096.6
SCB-120-50	240	132 to 144	50	308	1239

*Efficiency for all units $\approx$ 85% - power factor; 0.7 lagging.

†NIFE suggested input voltage is 240 Vac for all units; this allows for a practical service capacity.

4.3.7 Power Distribution

The power distribution includes all cabling and power switching associated with the PST system from the solar array and the utility to the house service breaker panel. The cabling, connector, and control requirements for the solar array/battery/inverter and ancilliary equipment are.

(1) Provide less than five percent loss for power circuits;

(2) Use lug termination for 12 gage and larger conductors;

(3) Use multicontact connectors for monitor circuits;

(4) Use switches capable of interrupting 200% of normal full load voltage and current;

(5) Accept switching commands from the control unit.

The power distribution design will use commercially available hardware. All equipment must meet national and local electrical codes where applicable. Control interconnections will use multi-conductor cable. Since cable size for power distribution is dependent on the length of the cable, and this is dependent on the equipment location or architectural plan, conductor sizing must follow the selection of a house plan.

4.3.8 Utility Interface Unit

The utility interface unit provides the interconnections and switching between the inverter output, the utility grid, and the house loads. Performance requirements for the utility interface unit are:

(1) Provide switching to permit ac power to be provided by:

(a) Utility grid;

(b) Inverter;

(c) Utility grid and inverter in parallel if enabled.

(2) Provide electromechanical and solid state switching;

(3) Provide electromechanical switches with mechanical interlock to permit selection of solid-state or electromechanical switching;

(4) Provide lightning surge protection;

(5) Control all switches through an interface with the control unit with capability to manually open and disable switches locally.

The performance requirements can be met using commercially available equipment for all electromechanical equipment and the enclosure. The solid-state switches are defined as part of the inverter control unit (paragraph 4.3.3). The magnetic amplifiers, the control circuits, and the interface with the control unit are new designs but are within current technology. A simplified functional diagram of the utility interface unit is shown in Figure 4-12.

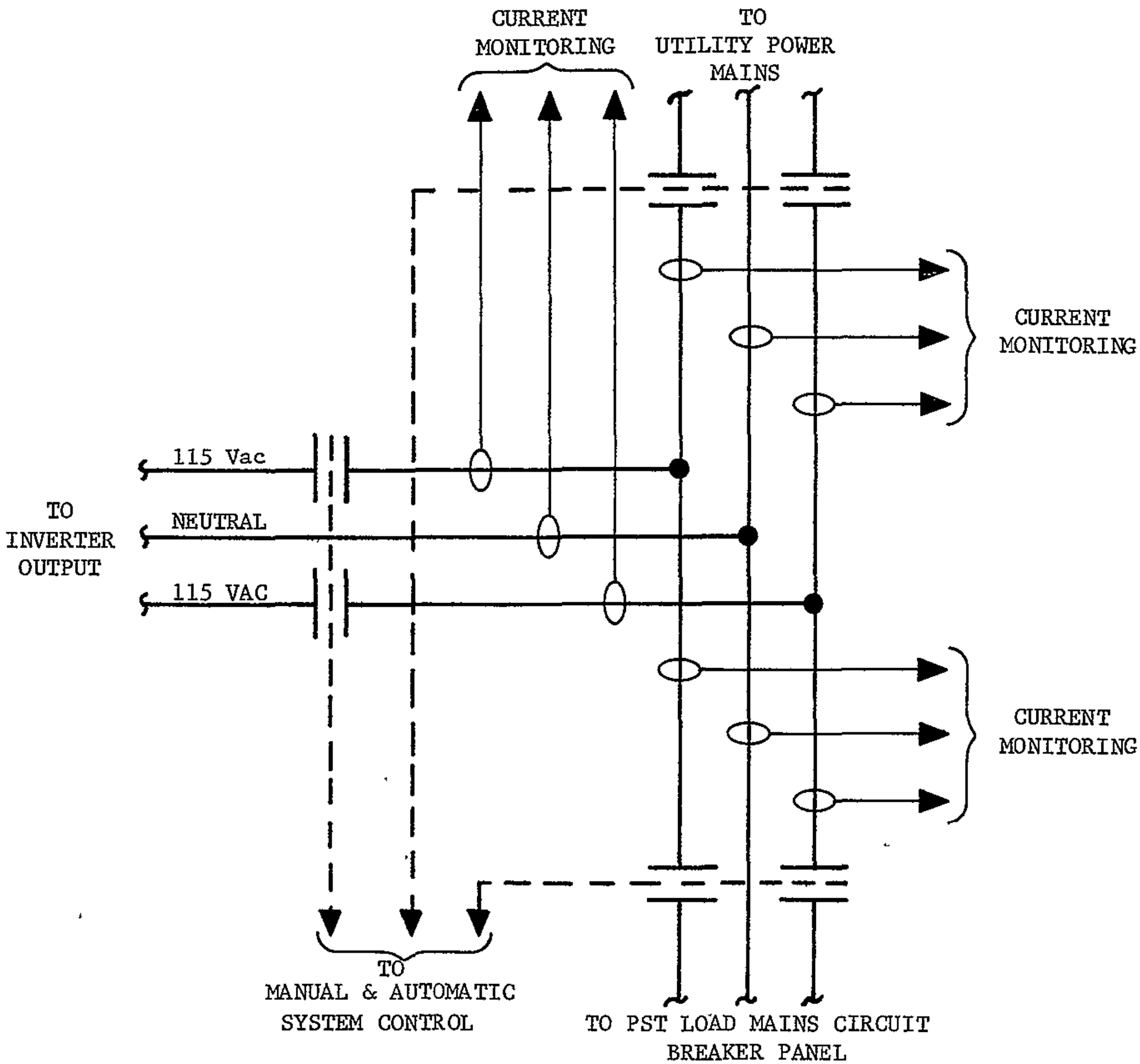

Figure 4-12 Utility Interface Unit Functional Diagram

4.3.9 Load Simulator

Performance requirements for the load simulator are shown in Table 4-8. The load simulator is included in the PST equipment to provide a means of loading the power with controlled resistive and reactive loads. The simulator is a new design and not an off-the-shelf item.

Table 4-8 Load Simulator Performance Requirements

Load Range
0 to 15 kVA at 240 V 0.1 kVA/Leg Increments
Power Factor
Lead - 0 to 0.95 for 0 to 3 kVA Lag - 0 to 0.95 for 0 to 15 kVA 0.05 Increments
Control
Digital Commands from Control and Display System Individual Control of Each Leg

Control of the load simulator will be provided by the control and display system which will issue commands to control switches in the simulator. Input to the control unit will identify the time, load magnitude, and the phase angle. The control and display system computer will determine the required switch settings.

4.4 Data Requirements

The data requirements for the configurations are based on obt obtaining detailed performance and environmental data. Additional data are obtained for fault detection and shutdown of the system. The measured parameters, quantity, range and required accuracy are defined in Table 4-9 for each configuration. Based on the measurements, certain parameters listed in Table 4-10 are calculated.

4.5 Control and Display System Description

The control and display system provides the overall control of the power system; the acquisition, recording and display of data; failure monitoring and system protection. The design concept of the system (see fig. 4-13) is based on a system used at Martin Marietta for control of battery tests and permits unattended operation of the system. The system consists of a control unit,

Table 4-9 Measurement List

Meas No	Measurement	Quantity Required	Measurement Units	Measurement Range	Accuracy Required	Configuration IIIA	IIIB	IIIC
1	Local Time	1	hr min sec	00 00 00 to 23 59 59	± 1 sec	X	X	X
2	Utility Voltage	2	Volts, ac rms	0 to 150	± 1%	X	X	X
3	Utility Voltage	1	Volts, ac rms	0 to 250	± 1%	X	X	X
4	Utility Current	3	Amps, ac rms	0 to 100	± 1%	X	X	X
5	Utility Power (true watts)	2	Watts, ac	-10,000 to +10,000	± 1%	X	X	X
6	Utility Power (true watts)	1	Watts, ac	-20,000 +20,000	± 1%	X	X	X
7	Load Voltage	2	Volts, ac rms	0 to 150	± 1%	X	X	X
8	Load Voltage	1	Volts, ac rms	0 to 250	± 1%	X	X	X
9	Load Current	3	Amps, ac rms	0 to 100	± 1%	X	X	X
10	Load Power (true watts)	2	Watts, ac	0 to 10,000	± 1%	X	X	X
11	Load Power (true watts)	1	Watts, ac	0 to 20,000	± 1%	X	X	X
12	Discrete Switch States	20	--	--	--	X	X	X
13	Inverter Output Voltage	2	Volts, ac rms	0 to 150	± 1%	X	X	X
14	Inverter Output Voltage	1	Volts, ac rms	0 to 250	± 1%	X	X	X
15	Inverter Output Current	3	Amps, ac rms	0 to 150	± 1%	X	X	X
16	Inverter Output Power (true watts)	2	Watts, ac	0 to 10,000	± 1%	X	X	X
17	Inverter Output Power (true watts)	1	Watts, ac	0 to 20,000	± 1%	X	X	X
18	Inverter Input Voltage	1	Volts, dc	0 to 300	± 1%	X	X	X
19	Inverter Input Current	1	Amps, dc	0 to 200	± 1%	X	X	X
20	Inverter Temperature	1	Degrees Celsius	0 to 100	± 1%	X	X	X
21	Reverse Output Current (Inverter)	2	Rms amps	0 to 5	± 5%	X		
22	Relative Phase - Displacement and Synchronization	1	Electrical deg	± 0 to 360°	± 2°	X		
23	Solar Array Output Voltage	1	Volts, dc	0 to 300	± 1%	X	X	X
24	Solar Array Output Current	1	Amps, dc	0 to 30	± 1%	X	X	X
25	Solar Array Temperature	18	Degrees Celsius	-40 to +90	± 0 5%	X	X	X
26	Subarray Voltage	90	Volts, dc	0 to 40	± 1%	X	X	X
27	Subarray Current	18	Amps, dc	0 to 2	± 0 5%	X	X	X
28	Wind Velocity	1	Meters/second	0 to 50	± 2%	X	X	X
29	Wind Direction	1	Degrees	0 to 360	± 2%	X	X	X
30	Ambient Temperature	2	Degrees Celsius	-40 to +50	± 1%	X	X	X
31	Ambient Pressure	1	psia	10 to 15	± 1%	X	X	X
32	Relative Humidity	1	Percent	0 to 100	± 1%	X	X	X
33	Total Intensity Sensor	2	Volts, dc	0 to 0 60	± 0.5%	X	X	X
34	Degradation Sensor	6	Volts, dc	0 to 0 60	± 0 5%	X	X	X
35	Hemispherical Solar Irradiance (Horizontal)	1	mW/cm^2	0 to 1500	± 1%	X	X	X
36	Hemispherical Solar Irradiance (Panel Angle)	1	mW/cm^2	0 to 1500	± 1%	X	X	X
37	Normal Solar Irradiance	1	mW/cm^2	0 to 1500	± 1%	X	X	X
38	Battery Voltage	1	Volts, dc	0 to 180	± 0 5%		X	X
39	Battery Module Voltage	4	Volts, dc	-10 to +50	± 1%		X	X
40	Battery Current	1	Amps, dc	-200 to +50	± 1%		X	X
41	Battery Temperature	2	Degrees Celsius	0 to 50	± 1%		X	X
42	Battery Cell Voltage*	60	Volts, dc	-2 0 to +3 0	± 0 5%		X	X
43	Battery Electrolyte Specific Gravity*	1	—	1 000 to 1 500	± 0 5%		X	X
44	Shunt Regulator/Aux Load Input	1	Volts, dc	0 to 300	± 1%	X	X	X
45	Shunt Regulator/Aux Load Current	1	Amps, dc	0 to 30	± 1%	X	X	X
46	Shunt Regulator/Aux Load Temp	1	Degrees Celsius	0 to 100	± 1%	X	X	X
47	Airflow Sensors	2		As Required		X	X	X
48	Smoke Detection	As Required - Digital Alarm Output				X	X	X

*Local Measurement Only

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Table 4-10 List of Computed Parameters

Data No.	Computed Data	Quantity Required	Data Units	Measurements Required	Configuration A	Configuration B	Configuration C
A	Integrated System Input Power	1	Kilowatt hours	1, N	X	X	X
B	Integrated System Output Power	1	Kilowatt hours	1, 17	X	X	X
C	Integrated Load Power	1	Kilowatt hours	1, 11	X	X	X
D	System Efficiency	1	Percent	17, 38, 40, N	X	X	X
E.	Utility Power (VAR)	2	VAR, ac	2, 4, 5	X	X	X
F	Utility Power (VAR)	1	VAR, ac	3, 4, 6	X	X	X
G	Load Power (VAR)	2	VAR, ac	7, 9, 10	X	X	X
H	Load Power (VAR)	1	VAR, ac	8, 9, 11	X	X	X
I	Inverter (VAR) Output Power	2	VAR, ac	13, 15, 16	X	X	X
J	Inverter (VAR) Output Power	1	VAR, ac	14, 15, 17	X	X	X
K	Inverter Output Power Factor	3	---	17, 17, I, J	X	X	X
L	Inverter Input Power	1	Watts, dc	18, 19	X	X	X
M	Inverter Efficiency	1	Percent	17, L	X	X	X
N	Solar Array Output Power	1	Watts, dc	23, 24	X	X	X
O	Solar Array Peak Power	1	Watts, dc	23, 24, 33, 34	X	X	X
P	Solar Intensity	2	mW/cm^2	33	X	X	X
Q	Power Degradation	6	Percent	34	X	X	X
R	Clearness Number	1	---	37	X	X	X
S	Sky Diffused Irradiance Factor	1	---	36, 37	X	X	X
T	Ground Reflected Irradiance Factor	1	---	35, 36, 37	X	X	X
U	Percent Sunshine	1	Percent	1, 36	X	X	X
V	Average Solar Array Temperature	1	Degrees Celsius	25	X	X	X
W	Integrated Solar Array Output	1	Kilowatt hours, dc	1, N	X	X	X
X	Integrated Battery Capacity	1	Ampére hours	1, 40		X	X
Y	Integrated Battery Capacity	1	Kilowatt hours	38		X	X
Z	Average Battery Cell Voltage	1	Volts, dc	38		X	X
AA	Shunt Regulator/Aux Load Power	1	True dc Watts	44, 45		X	X

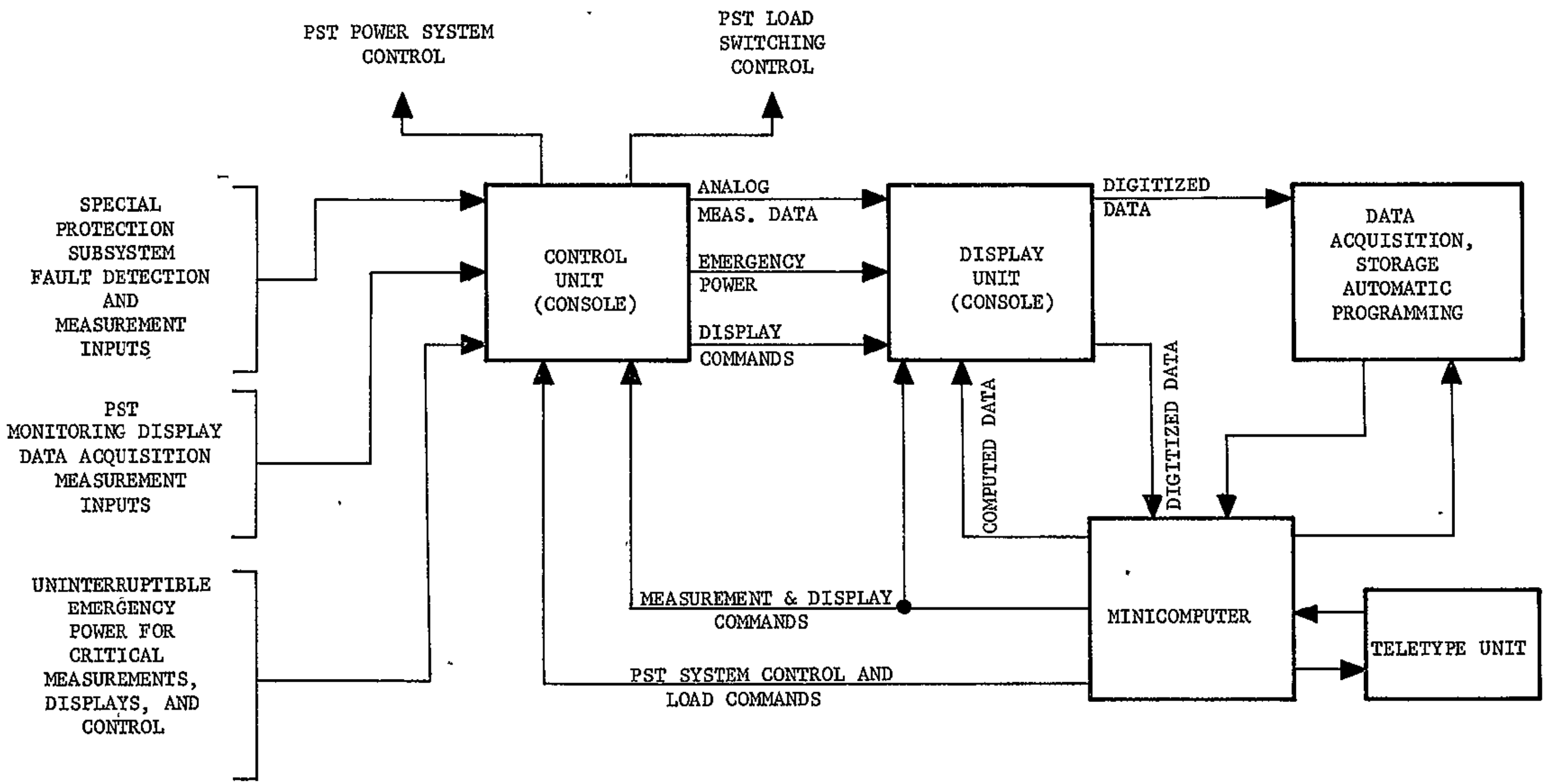

Figure 4-13 Functional Diagram, Control and Display, Showing Measurement Data Flow, Command and Control, and Data Acquisition

display unit, data acquisition unit, and a special protection subsystem. The performance requirements are summarized in Table 4-11.

4.5.1 Control Unit

The control unit executes all commands for complete PST system control, including load profile switching, and normal and emergency control of the entire power subsystem. All power subsystem measurements together with the special protection subsystem fault detection inputs are processed within the control unit which, by use of the data acquisition computer, performs decision-making and emergency command execution for the special protection subsystem functions.

Emergency (uninterruptible) power provisions are incorporated in the control unit to provide emergency power for critical measurements sensing, commands and displays relevant to the special protection subsystem. Measurement data, fault detection signals, emergency power, and display commands are then fed to the display unit for subsequent display and further processing.

Certain display commands relevant to the special protection subsystem functions are generated within the control unit on a priority basis. Other display commands are received from the minicomputer and utilized as necessary. All these commands are made available to the display unit. The normal PST operation and load switching commands are received from the minicomputer and are executed by the control unit.

4.5.2 Display Unit

The display unit consists of analog and digital meters and indicators to provide continuous, visual status of the PST performance. The measurements are processed in the display unit for panel display and converted to digitized format. These digitized data are in turn fed to the data acquisition unit minicomputer which provides further data processing and limited measurement computations. Computed measurements are fed back into the display unit for display purposes. Certain critical measurements and indications necessary for continuous display monitoring of the PST operation are displayed continuously by the display unit. Other monitoring measurements and indications are displayed by the display unit on command as received from the minicomputer and control unit. Data indicating causes for emergency shutdown or alarm initiation are flagged by the display unit panel indicators. They remain displayed until appropriate corrective action and circuit reset operations have been completed.

Table 4-11 Control and Data System Performance Requirements

Unit	Functions
Control Unit	Manual Control of Critical PST Power Switching All Measuring Functions for: -PST Monitoring, Display -Special Protection Emergency Power for: -Critical Measurements -Critical Control Functions -Critical Displays Executes all Control Commands -Manual Control (Switches) -Special Protection Subsystem Control -Operator or Software Controlled Commands from Data Acquisition Unit
Display Unit	Continuous, Direct Display of Critical Measurements. Manually Switched Displays -Operator Control - Manual Switches - Keyboard Command -Software Controlled Receives all Measurements from Control Unit, Converts to Necessary form for -Display -Data Acquisition Maintains Display of Fault Mechanisms.
Data Acquisition	Provides Automatic (Programmed) Control of System Operation Stores Measured Data -Temporary for Averaging -Temporary for "Real-Time" Calculations -Permanent File of Averaged and Computed Data
Control Unit (Processor)	Processes Operator Requests -Switching Changes -Load Changes -Data Hard Copy -System Configuration Performs Computations -Data Averaging -Computed Parameters for "Real-Time" Display (e g , VAR)
Special Protection	Fault Sensing -Smoke Detectors -Over/Under Voltage Sensing -Over/Under Current Sensing -Over Temperature Sensing -Inverter Phase/Frequency Synchronization with UG Reaction Mechanisms (Failure Response) -PST System Control (Shutdown) -Computer Monitor -Alarm -Panel Display -Emergency Power -Battery Enclosure Ventilation -Shunt Regulator full-on Conduction Passive/Manual Protection -Lightning Protection -Surge Arrestor on Solar Array Bus -Surge Arrestors on Utility Service -Equipment Access Interlocks -Solar Array Blanket -Manual Bus Disconnects

4.5.3 Data Acquisition Unit

This portion of the system consists of a minicomputer and its peripheral equipment. The system requires 8 to 12K memory with 12 bit words; a disk system for program and interim data storage; a tape deck for mass data storage; a paper tape reader and punch for programming; and operator control via a teletypewriter. (It may be possible to use a microcomputer instead of the minicomputer with a cost, power, and volume saving.)

All data are digitized within the display unit and fed into the data acquisition unit minicomputer for evaluation and data recording. System control commands are generated by the minicomputer and necessary computations are performed. Command and measurements data are made available within the minicomputer for teleprinter readout. Programming for the minicomputer may be accomplished by teletypewriter keyboard or by loading from tape.

4.5.4 Special Protection Subsystem

The special protection subsystem provides protection for the PST electrical equipment. The functions include fault sensing, reaction mechanisms, and passive protection.

The fault sensor out-of-limit condition will cause commands to be issued from the control unit to operate the switches required to shutdown the system. The fault sensing primarily uses system measurements which are limit-checked by the computer with a shutdown command issued to the control unit, if required.

Reaction mechanisms provide redundant response to a shutdown command to assure disconnect of the utility, retention of cause of shutdown indication, and issuance of alarms. Emergency power is provided to required equipment for lightning, ventilation, and displays.

Lightning and surge protection and personnel protection are provided by passive elements. A manually deployed blanket provides protection of the solar array from the sun for maintenance or from the elements during severe weather. Manual bus disconnects and an array shorting switch provide protection during maintenance.

4.6 Maintenance and Safety Considerations

Equipment maintenance and special safety requirements must be minimized if a practical solar power system is to be developed. Some maintenance requirements must be determined during PST testing. Specific safety and maintenance requirements, other than requirements defined by a commercial equipment manufacturer, are defined below:

4.6.1 Solar Array

Maintenance - Cleaning of the solar array and related sensors shall be done periodically as determined during PST testing. The time period will be affected by dust, humidity, rain, etc. Areas requiring periodic cleaning are: (1) solar array surface; (2) solar array degradation sensors; and (3) atmospheric measurement sensors. Daily cleaning is required on the intensity measurement sensors.

The solar array installation shall permit easy access for module and component (diode, shunt resistors, etc) replacement.

Safety - Because of high voltages, work on the solar array must be done with the array covered or at night.

4.6.2 Battery

Maintenance - Maintenance and safety requirements for the battery and battery installation are: (1) check battery electrolyte level periodically and add water as required; (2) periodically inspect and clean, as required, the battery terminals; and (3) check specific gravity of electrolyte in cells and replace cells failing to meet manufacturers recommendations.

Safety - Safety requirements are:

(1) Locate battery in a limited access enclosure equipped with an air exhaust system. Include a water supply and floor drain. Do not allow spark producing equipment.

(2) No smoking in battery enclosure;

(3) Wear face mask, rubber shoes and gloves when servicing;

(4) Do not place tools or equipment on the battery.

4.6.3. Inverter

Safety - Nonoverride interlock switches shall completely de-energize the inverter when the covers or access doors are opened.

4.6.4 Shunt Regulator/Auxiliary Load

Safety - Electrical cabinet locks shall be provided to preclude access until the PST has been shutdown and any power dissipative elements have cooled.

4.6.5 AC Battery Charger

Safety - Nonoverride interlock switches shall cause interruption of input power and disconnect of the output when the covers or access doors are opened.

4.6.6 Power Distribution

Maintenance - The electromechanical switch contacts shall be inspected periodically for erosion and replaced as required.

Safety - For safety protection from high voltage ac or dc present in the distribution system: (1) when possible remove all power from the area of work and ground the bus; and (2) use protective gloves and insulated tools.

5.0 TASK IV - TEST PLAN

The objective of Task IV was to define a test plan to 1) enable implementation of the residential photovoltaic PST described in Task III, and 2) collect and analyze the key performance parameters defined in Task II. This section presents the overall summary of the test plan; Appendix C contains the detailed plan.

The test plan defines the overall requirements of the test program for the residential photovoltaic PST. It basically covers the test and management control requirements listed below.

Test Program

(1) Subassembly Tests - Tests to be performed on solar array and battery subassemblies before initial installation and on replacement units.

(2) Startup Tests - Tests to be conducted to verify the performance of the key components and compatibility of their interfaces (e.g., inverter, ac charger, battery / ac charger, etc.).

(3) Component Tests - Tests to be performed on individual components and power distribution subsystem during the system tests. These include solar irradiance and atmospheric measurements which affect solar array performance and which are required to predict the solar array output capability.

(4) System Configuration Tests - Tests to be conducted to verify system performance on EPS Configuration IIIA, IIIB, and IIIC. Tests are recommended to be performed periodically.

Test Procedure

Requirements for the test procedure are defined, including test methods and sequence, instrumentation, test condition, and data reduction and computation.

Software

The software required for the minicomputer for the control of the EPS and real-time data display, and data reduction using off-line central computer facility are defined.

Reports

Requirement for quarterly and annual reports are defined.

Schedule

The basic PST schedule is given for the initial 24-month period.

Servicing and Maintenance

Components and sensors that require periodic calibration and maintenance are defined.

Safety

Requirements to provide minimum personnel safety provisions are defined relative to the components and subsystems.

Test Management

PST program schedule and cost control requirements are delineated.

Estimated Operating Cost

Operating cost is defined in terms of the manpower required by skill and data reduction effort, including use of off-line computer.

Procurement

The estimated lead time for the procurement of critical components and test equipment is given. Components requiring development are the full shunt regulator and the inverter control unit (for Configuration IIIA only).

6.0 TASK V - TEST PROCEDURE

The objective of Task V was to identify and describe all test equipment and procedures required to implement the PST program. This section presents the summary of the test procedure; Appendix D contains the detailed procedure.

The test procedure is based on the requirements set forth in the Test Plan in Section 5.0. It defines the test methods and sequence for each major test identified. The test procedure is described in terms of the setup, operation, measurements, and data reduction and analysis.

Special instrumentation requirements defined are related to solar irradiance measurements. These are the normal incidence pyrheliometer, pyranometer which has a 180-degree field of view, and a detector for determining the percentage of sunshine (above certain intensity) in a given daylight period.

Sampling rate and frequency of data collection are defined. The data are to be stored on standard nine-track magnetic tape. Because of the potentially large amount of data to be collected and analyzed, data reduction via off-line computer facility (e.g., the UNIVAC 1108 or CDC 6500) is recommended. Included in the test procedure are sample formulae for the calculation of certain performance parameters.

7.0 TASK VI - IDENTIFICATION AND EXAMINATION OF INSTITUTIONAL PROBLEMS

7.1 . Introduction and Summary

The objective of this task was to identify potential institutional problems associated with implementation of the residential Prototype System Test (PST). The institutional problems were defined in the areas of legal liabilities during and after installation of the PST, labor practices, building restrictions, architectural guides, and land use. The key problems identified are as follows:

Legal

1. Adequate public safety provisions should be made during PST operation;

2. Method of complying with utility interface requirements and constraints must be determined;

3. Use of non-UL approved hardware in the PST may present problems such as insurability.

Labor Practices

1. PST may require trades not conventionally involved in residential construction;

2. Conflict between job trades may develop due to PST.

Building Restrictions and Architectural Guides

1. The Uniform Building Code does not cover use of photovoltaic devices for residential structures;

2. Building constraints vary at different geographical locations.

Land Use (as related to general application of photovoltaic systems).

1. Land use planning may be hampered by use of photovoltaic systems.

2. Use of solar energy as a stimulus to growth is poorly understood and accepted.

3. Guidelines on proper orientation of structures to use solar energy do not exist.

4. Environmental impact statements are required, especially on large scale application of photovoltaic systems.

7.2 Legal Liability

Legal liabilities are expected to generally conform to typical conventional liabilities, with some modification due to the nature of the prototype system installation and tests. As a generality, actual structural construction is normally preceded by a number of activities as outlined in Table 7-1. These preconstruction activities are generally initiated with tentative site selection and ended with actual construction preparations.

Table 7-1 Preconstruction Procedures for Residential Structures

Tentative site selection.
Identification of building codes, zoning regulations, covenants, fire zone classification, etc.
Survey of easements (access, etc) necessary to property habitation, and usage.
Identification of jurisdictional building authority.
Preliminary coordination with utilities.
Examination of projected land zoning and land usage in immediate area over next decade.
Identification of utility easements and building restrictions.
Preliminary architectural drawings and examination of architectural compatibility with codes, regulations, easements, and building restrictions.
Identification and examination of any unique problems.
Site acquisition and acquisition of any special easements.
Final architectural plans, drawings, and compliance with regulations, and covenants.
Building permits.
Preparation and letting of building contracts.
Insurance coverage (liability), contractor bonding.

C·3

A number of special problems identified uniquely with the PST are outlined in Table 7-2. Guaranteed solar access, somewhat unique structural use and occupancy, and power system aspects for residential-type structures will possibly lead to special easements and adaptation of existing building/installation code requirements for the PST type of residential structure.

Table 7-2. Special Problems Identified with Preconstruction

Special easements pertaining to guarantee of solar energy access and unattenuated solar intensity.
Assessment of unique structural use (public access, demonstrations) as related to zoning regulations, building codes, and covenants.
Special building occupancy, use classification with regard to conventional building code classifications.
Identification of unique hazard items, unique aspects of power system, and coordination of special structural and installation requirements with standard requirements applicable to existing codes, regulations, and zoning requirements.
Identification of unique liability and hazard insurance protection and compliance requirements.
Identification of special solar array protection requirements (lightning protection, structural loading, environmental hazards, etc) and compatibility of structural design with insurance requirements and zoning and building regulations and codes.
Identification of construction requirements that may improve building trade job compatibility problems and the solutions of problems to provide such compatibility.

Table 7-3 outlines the general liabilities associated with actual construction. Table 7-4 outlines the general liability considerations following construction and during actual PST operation.

Table 7-3. General Liabilities Associated with PST Construction and Installation

Construction liabilities and adherence to plans, specifications, codes, regulations, and covenants.
Public liability with regard to construction and construction hazards.
Adherence to standard labor practices.
Compliance with periodic inspection procedures required by contracts, agreements, building codes, and regulations.
Appropriate safety procedures for personnel protection (including public) and insurance compliance.
Compliance with utility interface requirements.

Table 7-4. General Liabilities Following Construction and During PST Operation

Adherence to previously determined habitation/occupancy codes and regulations.
Public liability and public safety.
Technical operational adherence to previously established regulations, ordinances, codes, and covenants.
Safety regulation compliance for protection for public and technical personnel, and adherence to insurance requirements.
Fire code compliance.
Maintenance of external easements for guaranteed unobstruction of solar energy and PST continuance.
Compliance with utility interface requirements and constraints.
Use of PST hardware not approved by UL.

Local jurisdictional requirements can be expected to vary as to selection of building materials, construction and installation requirements, and fire and safety code compliances. Other considerations, including insurance compliance and requirements, could also conceivably vary depending on location and jurisdictional authority. The PST system/utility grid interface may have to be handled somewhat differently with individual utility companies.

However, uninterruptible power systems (UPS) have been in existence and have been accepted for a number of years. The utility grid (UG) interface similarity between the UPS and the PST might solve the problem of paralleling the inverter and UG when supplemental power is required, based on the established UPS/UG interface precedences. These precedences could also serve to alleviate the occurrence of unique electrical code compliance problems.

One solution to problems associated with the possible variances of jurisdictional authority for prototype system installations and tests might be to identify a central authority, possibly in Washington, D.C. that would have the required official building and land use authority over all selected federal (non-DOD) land sites. This could halp provide uniform requirements for all PST sites and might establish useful precedences for later uniformity in requirements when the photovoltaic system may not be located on federal lands and would therefore be subject to local authority and interpretations.

7.3 Labor Practices

With any new field, the potential of labor practice problems exists. These problems may involve new or upgraded skill requirements or conflicts over equipment jurisdiction.

The PST system requires wiring practices exceeding those normally encountered in residential applications. The battery installation in a protective enclosure involves a level of installation and electrical wiring skill not normally encountered in residential construction. These skills, however, are not unlike those that are required in industrial construction.

Multiple trades may claim jurisdiction for installation of equipment such as the solar array. Roofers and electricians may consider it their responsibility and the design of the solar array may figure in the solution. An array which forms part of the roof may be installed by roofers; an array built up on a structure away from the roof may be installed by electricians.

Potential labor practices are outlined in Table 7-5.

Table 7-5 Potential Labor Practice Problems

Special building, structural, and installation requirements might involve trades not conventionally involved in residential construction.
Power system technology, including solar array, should be made compatible with existing trade capabilities and job functions.
Design care should be exercised to avoid conflict between trades (e.g., whether solar array installation should be done by roofing trade or electrician trade).
Labor relations to prevent conflict between job trades.

7.4 Building Restrictions and Architectural Guides

Building restrictions are normally determined by a number of factors including occupancy/use classification, zoning (including ordnances and covenants), and ownership (federal, state, private). Table 7-6 is a general outline of the building considerations normally identified in building codes. Each of these considerations is additionally composed of numerous details and subject to local building codes and jurisdictional authority.

Table 7-6. Normal Building Considerations

Structure Occupancy/Use Definition	Means of Egress
Special Hazard Identification	Vertical Openings
Type of Construction	Hazardous Areas
Structure Area Requirements	Light and Ventilation
Structure Height Requirements	Electrical Installation and Wiring
Fire Protection System	Sanitation
Fire Limit Requirements	Structural and Foundation Loads, Stresses (Including Live and Dead Loading)
Fire Resistance	Building Materials
Interior Finish	
Exterior Protection	

Using the Uniform Building Code as an example, a special occupancy classification may pertain to the residential-type PST structure. This could have broad implications including building and structural requirements and fire and safety code compliance. Section 501 of the Uniform Building Code states:

> *"Sec. 501. Every building, whether existing or hereafter erected, shall be classified by the Building Official according to its use or the character of its occupancy, as a building of Group A, B, C, D, E, F, G, H, I, or J, as defined in Chapters 6, 7, 8, 9, 10, 11, 12, 13, 14, and 15, respectively. (See Table No. 5-A)*
>
> *"Any occupancy not mentioned specifically or about which there is any question shall be classified by the Building Official and included in the Group which its use most nearly resembles based on the existing or proposed life and fire hazard."**

The Building Officials and Code Administrators International, Inc. (BOCA) basic building code defines a use group classification system that is somewhat different from the Uniform Building Code classification system. Building classification could vary at different geographical locations in the United States because of local building codes and local jurisdictional interpretations.

There are no specific sections of the *Uniform Building Code*, 1975 Edition, which refer to use of a photovoltaic system for generating electrical power in a single family residence.

All of these items, as well as terrain and topography analysis, environmental factors and stresses, and soil and subsoil analysis enter into architectural considerations. Additional architectural requirements include detailed plans and specifications indicating the nature and extent of the proposed work and conformity to relevant codes, laws, ordnances, and regulation. In general instances, plot plans showing locations of proposed structures and existing structures are required. Other required architectural information may include computations, stress diagrams, and sufficient data to show correctness of plans. These guidelines may vary in detail with location and local jurisdictional authority.

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*Uniform Building Code

7.5 Land Use*

The Environmental Law Institute in Washington, D.C. received a grant (APR75-18247) from the National Science Foundation (NSF) in June of 1975 for research concerning legal and institutional impediments to early private sector demand for solar energy equipment and design of alternative incentives for overcoming these barriers.

The institute is completing an analytical case study of the State of Colorado, concentrating on its governmental structure and on its decision-making powers and authorities in the land use field as these affect solar development, both for individual structures and large acreage applications. The project is being conducted by an interdisciplinary team of two lawyers, a political scientist, and a solar energy specialist in Colorado.

The following material (relative to the solar energy land use planning) was extracted from an interim study report prepared by Karin Hillhouse, *et al.*, for the Solar Energy Project titled, *Solar Energy and Land Use in Colorado*, dated April 1976.

> "The orderly use and development of land is a prime objective of land use planning. Use of solar technologies may either further or hamper attainment of this goal. While most solar energy systems are clean and therefore compatible with more land uses than are fossil fuels, the dispersed nature of the solar energy resource and hence, the decentralized character of solar heating and cooling systems could have an adverse effect on efforts to manage growth. The goals of land use planning must be reconciled with the needs of solar energy if the maximum benefits of both are to be realized. We have titled an approach that meets these objectives (solar land use planning). Some tentative judgments regarding relevant considerations in this approach follow.
>
> "1. Land requirements for solar energy technologies will probably be far less than those for alternative energy sources. One study has concluded that An optimal combination of (solar energy systems) would require only about 1.4% of the total U.S. land area to supply 100% of the estimated energy needs of the U.S. Moreover,

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*Information contained herein was obtained from the principal investigator, Karin H. Hillhouse, who is residing in Denver, Colorado.

while the mining of coal or other fossil fuels requires additional amounts of land each year, solar energy is infinitely renewable. Collectors for solar heating and cooling systems can be placed on top of buildings and therefore need not require any additional land. Since land is an important resource for planning purposes, this feature of solar energy systems could make them highly attractive to land use planners.

"2. The importance of energy services as a stimulus to growth is so far poorly understood. As energy costs become a higher fraction of total housing costs, it seems reasonable to expect that the relationship between energy and growth will become more significant. If solar energy technologies begin to allow homeowners to live largely independent of utility services, the government's ability to provide for orderly growth may be weakened.

"3. The most efficient forms of solar energy technologies may be much smaller than the large electric generating stations which continue to play a central role in utility planning. Solar heating and cooling technologies offer little or no savings from increasing size. Photovoltaic cells also are likely to be produced in a relatively small size that could be purchased directly by homeowners. The decentralized, independent nature of these solar systems could pose a threat to orderly development (see #2 above), but it also could be a highly positive force. Large energy systems may prove to be unworkable or at least highly inefficient. . . . The complexity created by attempting to transact business between several states is another problem. Regulatory officials in California, for example, are attempting to impose a certification requirement on construction of the proposed Kaiparowits power plant in Utah because electricity from the plant would go to California. In another vein, a court in North Dakota has ruled that eminent domain may not be exercised for the purpose of transporting electricity out of the state. Eminent domain must be exercised for a valid "public purpose," and the court held that the needs of citizens in other states do not satisfy this standard. If these increasingly dominate the planning and construction of large electric systems, solar energy might be viewed as the basis for smaller and more workable energy delivery systems.

"4. One of the ultimate objectives of solar land use planning will be to insure proper orientation of structures to receive sufficient sunlight to operate a solar collector efficiently. Zoning provisions will likely provide the mechanism for such orientation within areas already developed. In the more rural, developing sections of Colorado, subdivision regulations may offer a means by which the energy dynamics (terrain, vegetation, wind velocity, insolation, precipitation, etc.) of a particular site can become an integral part of the land use decision-making process. The basic design and orientation of a building ideally respond to these site characteristics. The efficient use of a solar hardware system will depend on the quantity of solar energy present at the site, climate conditions, comfort levels required, and the type of building, including its relationship to the site and its structural and thermal characteristics.

"5. Environmental impact statement requirements have been adopted by some state and local governments as a basis for evaluation of proposed developments. Such statements could become the basis for institutionalizing consideration of the energy impacts of development and of the feasibility of solar energy alternatives. Even if such systems are in fact not yet economically competitive, regular evaluation in impact statements would educate developers regarding solar energy alternatives and add to their acceptability. Commenting on impact statements also offers state and local governments a way to promote consideration of solar energy by federal agencies.

"6. Areas anticipating energy shortages might want to undertake comprehensive energy planning. Such an approach might include stiffened minimum insulation requirements, energy conserving construction standards, and clustered land use patterns that would facilitate use of solar energy systems."

8.0 CONCLUSIONS AND RECOMMENDATIONS

The significant conclusions and recommendations of this study are as follows:

(1) Site selection study for potential PST locations revealed problems in locating sufficient candidate sites in some geographical regions on federal, non-DOD properties. Therefore, it is recommended that state-owned land also be included in future site selection activities.

(2) A power system configuration, containing only the solar array, inverter, shunt regulator, and associated control circuitry provides the best overall performance and is the most cost-effective arrangement for the PST program.

(3) The configuration without the battery as compared to that with the battery yields a substantially higher energy displacement (ratio of energy supplied by the PST power system to the total energy used by the residential electrical loads) computed over a one-year period.

(4) The solar array size can be significantly reduced by eliminating the battery (i.e., eliminating the energy storage requirement and using the utility source for night power demand). However, the use of a battery is recommended as part of the PST program for experimental purposes.

(5) Solar insolation, electrical load demand, and inverter efficiency are the most sensitive parameters affecting the PST power system performance. To minimize power losses and achieve a high system operating efficiency over a widely varying power demand, use of several inverters of various ratings is recommended.

(6) The most important factors affecting the size of the solar array and battery are as follows:

Solar array - insolation and electrical load, including battery recharge energy, and inverter efficiency, and the duration of array/battery energy balance to be achieved (i.e., 1-, 2-, or 3-day period, etc.).

Battery - night energy demand at the bus, inverter efficiency, solar array capability, and duration of array/battery energy balance desired.

The sizing of these components for the various PST sites should therefore consider the annual insolation profile and the power demand profile for a given site.

(7) In the case of the PST inverter operating electrically in parallel with the utility grid, a detailed evaluation of the overall technical compatibility is recommended.

APPENDIX A

DERIVATION OF THE PST COMPUTER MODEL

1.0 INTRODUCTION

Appendix A describes the following four basic models comprising the PST Computer Program:

Solar Irradiance Model (Section 2)
Solar Array Model (Section 3)
Electrical Load Model (Section 4)
Energy Balance Model (Section 5)

In addition, the references cited in this Appendix is provided in Section 6.

2.0 SOLAR IRRADIANCE MODEL

A solar irradiance model (SIM) was developed to provide estimates of the total solar irradiance (defined in the following paragraphs) falling upon a solar cell array panel having a given tilt angle (angle above the horizon) and azimuth angle (angle the normal to the panel makes with respect to true north), located at given sites in the United States. The general approach was to keep the model as simple as possible to keep development cost to a minimum and to keep the computer time required to execute the model to a minimum.

The minimum development time and cost requirement necessitated the adaptation of existing solar irradiance models. Since many such models exist, an extensive search and review of such models would be a major task and beyond the scope of the intended effort. The criteria for selecting the solar irradiance model were as follows:

(1) Model should be simple and functional.

(2) Model should allow various atmospheric conditions (water vapor, clarity, cloud cover, amount of sunshine) to be addressed.

(3) Model should allow various solar panel tilt angles and azimuth angles to be addressed.

(4) Model should use a minimum of computer time.

(5) Model should allow the effects of ground reflectance to be addressed.

(6) Model should allow any selected site within the United States to be addressed.

The selected model meeting the above criteria was described and compiled by Yellott and MacPhee (Ref. A-1). This model resulted from an NSF grant to the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) for a comprehensive study of currently available design data. This same model was used and expanded to include observations of cloudy day conditions by Tamami Kusuda (Ref. A-2) of the National Bureau of Standards. This was based upon actual observed clouds versus solar irradiance data by Kimura and Stephenson (Ref. A-3). The model developed by Kusuda is called the National Bureau of Standards Load Determination (NBSLD) program. A section of this model is termed SUN, from which SIM was patterned. The following sections delineate the effort conducted in this study involving the modification of these basic solar irradiance models to incorporate historical data of percent possible sunshine and mean sky cover, as given in the *National Climatic Atlas*. The objective is to achieve fairly accurate estimates of total solar irradiance using an economical model and historical data for percent sunshine and mean sky cover.

1.1 Basic Concepts of Solar Irradiance - The total instantaneous solar irradiance H(p), on a solar array panel is made up of three components: (1) the direct solar beam irradiance H(d); (2) the diffuse (scattered) sky irradiance, H(s); and (3) the reflected ground irradiance, H(r). These components make up the total irradiance as given by:

$$H(p) = H(d) + H(s) + H(r) \qquad (1)$$

The following sections describe the specific mathematical relationships and techniques used to derive these quantities for clear and cloudy conditions.

1.2 Total, Direct, and Diffuse Solar Irradiance for Clear Conditions

The direct solar irradiance on a panel for a clear day is calculated by:

$$H(d)cr = I(cr) \cos \theta \qquad (2)$$

where I(cr) is the irradiance of the normal incident solar beam (clear day) and θ is the solar incident angle (fig. A-1) to the panel. For the special case of a horizontal panel, θ becomes the solar zenith angle, θ_o. The complete set of geometrical definitions, as shown in Figure A-1, are as follows:

L, Latitude, degrees + North
- South

l, Longitude, degrees + West
- East

PT, Panel Tilt Angle

PA, Panel Azimuth Angle, radians from South, (+) if West, (-) if East

ϕ, Solar Altitude Angle

ϕ_o, Solar Azimuth Angle

θ, Solar Incident Angle

θ_o, Solar Zenith Angle

d, Day number (0-366)

t, Time, hours from midnight

ET, Equation of time

δ, Solar declination angle

h', Angle from true South to azimuth of sunset

h, Hour angle, in degrees

TZN, time zone number (4 to 8)

SRT, sun rise time

SST, sun set time

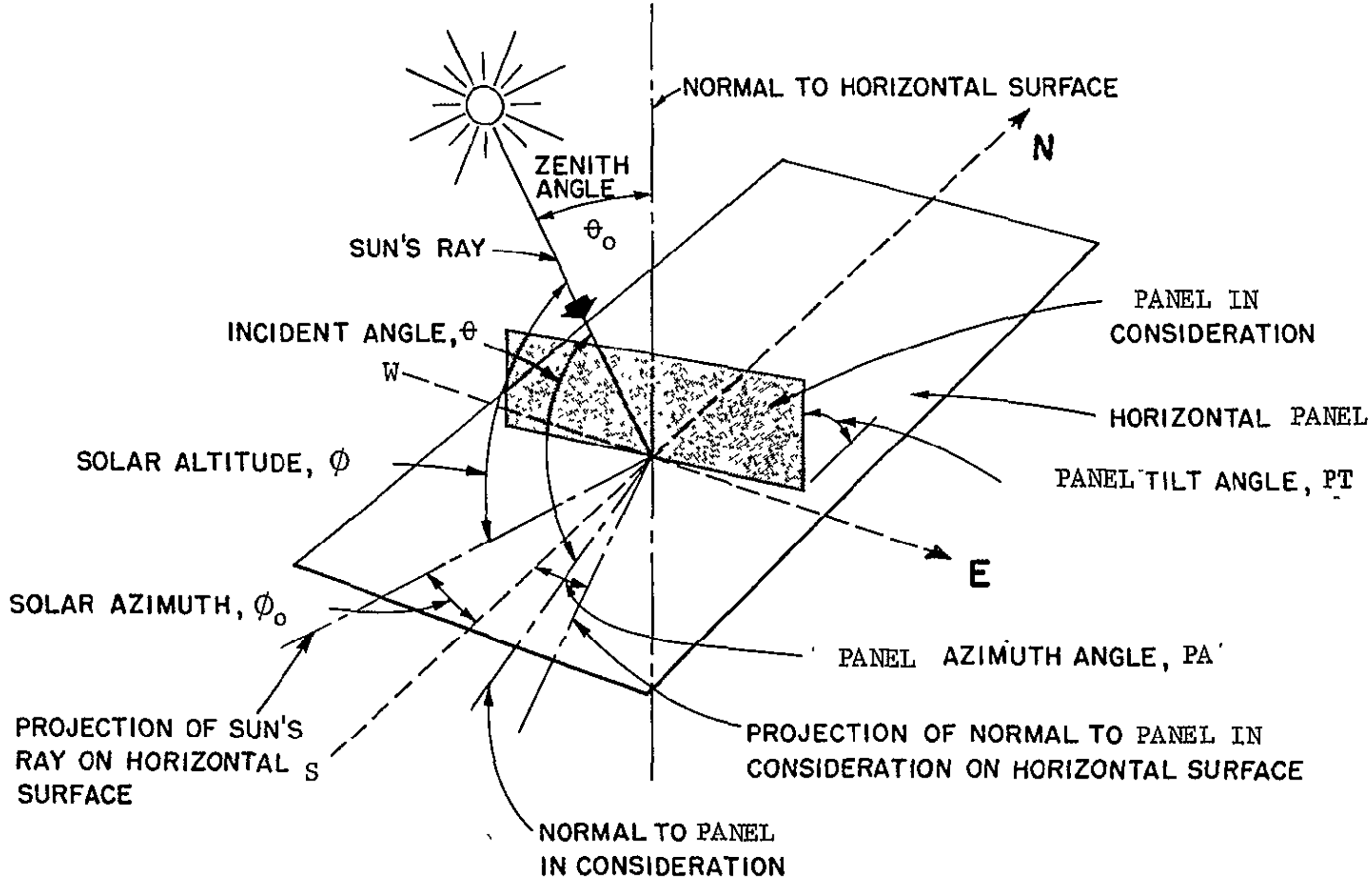

Figure A-1 Geometrical Definitions of Solar and Panel Parameters

The following is a sequential derivation of the relationships between all of the above geometrical parameters based upon references A-1, A-2 and A-4:

$$\sin \delta = \sin (23^{o}\ 26'\ 37.8'') \sin \sigma \qquad (3)$$

$$\sigma\,(\mathrm{deg}) = a + 0.4087 \sin a + 1.8724 \cos a$$

$$- 0.0182 \sin 2a + 0.0083 \cos 2a \qquad (4)$$

$$a\,(\mathrm{deg}) = 279.9348 + b$$

b = angular fraction of a year represented by a particular date (5)

$$b = (d - 1)\ 360\ \mathrm{deg}\ /365.242 \qquad (6)$$

$$ET = 0.12370 \sin b - 0.004289 \cos b$$

$$+ 0.153809 \sin 2b + 0.060783 \cos 2b \qquad (7)$$

$$h' = \cos^{-1} \left[-\mathrm{Tan}(L)\ \mathrm{Tan}\ (\delta)\right] \qquad (8)$$

$$y = h' + 12/\pi \qquad (9)$$

$$SRT = 12.-Y-ET + 1/15 \qquad (10)$$

$$SST = 12.+Y-ET + 1/15 \qquad (11)$$

$h = 15\ (t - 12 + TZN + ET)$ if $|h| > |h'|$, set direct, diffuse and ground reflected irradiance = 0 (12)

Direction cosines of direct solar beam is

$$\cos \theta_o = \sin L \sin \delta + \cos L \cos \delta \cos h \qquad (13)$$

$$\cos W = \cos \delta \quad \sin h$$

$$\cos S = \left[\left(1-\cos \theta_o \right)^{2} (\cos W)^{2} \right]^{0.5}$$

$$\phi_o = \sin^{-1} (\cos \theta_o) \qquad (14)$$

if $\cos S > 0$

$$\phi_o = \sin^{-1} (\cos W/\cos \phi)$$

if $\cos S < 0$

$$\phi_o = \pi - \sin^{-1} (\cos W/\cos \phi) \qquad (15)$$

Direction cosines of normal to panel are:

$$\alpha = \cos(PT)$$

$$\beta = \sin(PA) \sin(PT)$$

$$\gamma = \cos(PA) \sin(PA) \qquad (16)$$

$$\cos\theta = \alpha \cos \theta_o + \beta \cos W + \gamma \cos S \qquad (17)$$

In order to calculate these geometrical relationships, the required inputs are time zone number, latitude, longitude, and day number.

The normal incident solar irradiance is calculated by:

$$I'(cr) = I_o(d)e^{-\tau \sec\theta_o} \qquad (18)$$

where I_o (d) is the extraterrestrial solar irradiance at a given earth-sun distance, τ is the total atmospheric optical depth, and $\sec\theta_o$ is the relative air mass (slant path). The total atmospheric optical depth is made up of components due to the atmospheric attenuation processes of molecular scattering $\tau(M)$, aerosol/particulate scattering $\tau(p)$ and absorption $\tau(a)$; hence,

$$\tau = \tau(M) + \tau(p) + \tau(a) \qquad (19)$$

As shown in Figure A-2, molecular and aerosol scattering are the predominant attenuation processes in the visible region, whereas, water vapor absorption dominates the near-infrared region.

From Handbook of Geophysics and Space Environment, S. L. Valley, Ed (New York: McGraw-Hill Book Company, Inc.), p. 16.2.

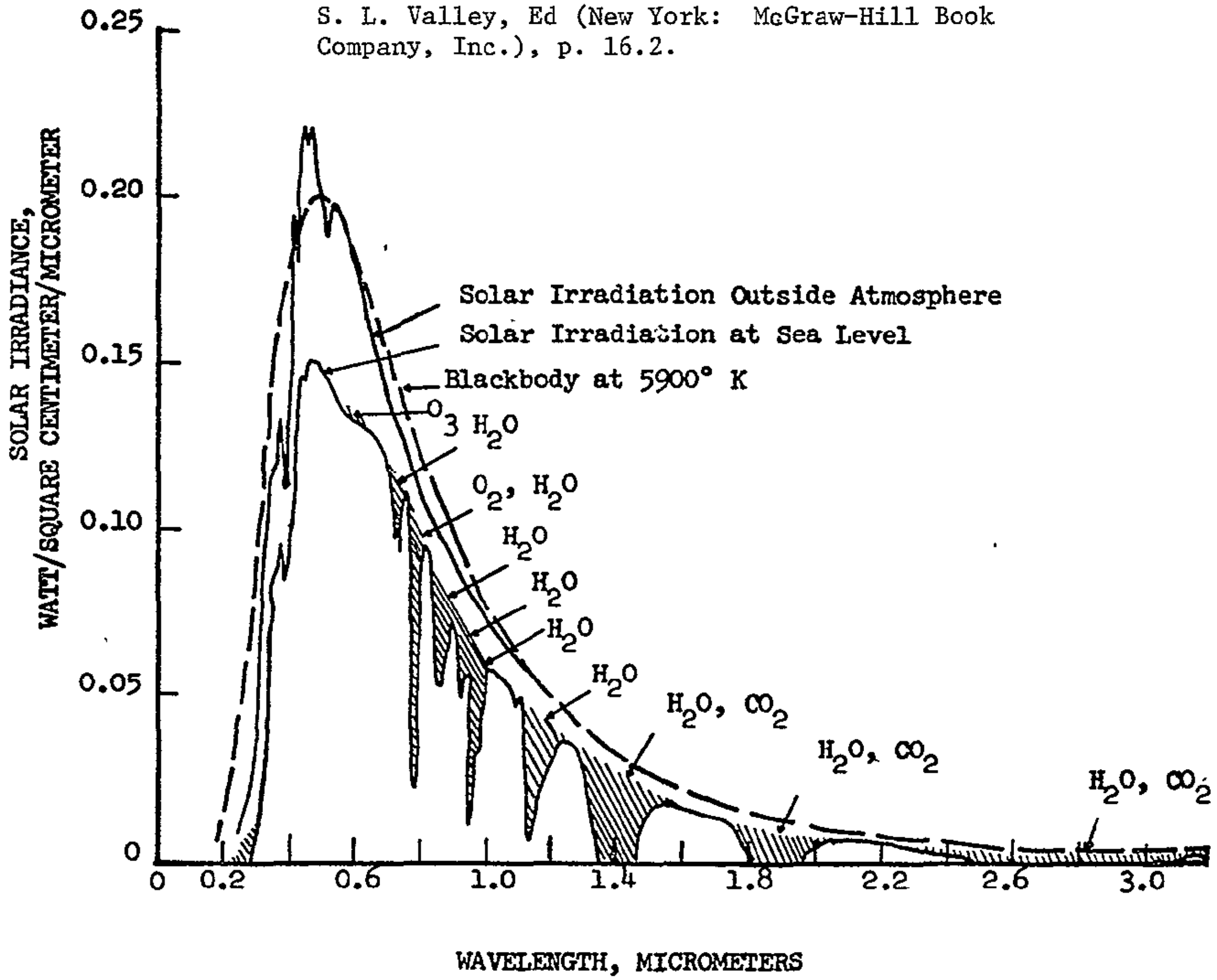

Figure A-2 *Typical Spectrum of Solar Energy Reaching the Surface of the Earth*

The value for $I_o(d)$ is calculated as a function of time of year by:

$$I_o(d) = I_o(M)\ D \tag{20}$$

where $I_o(M)$ is the extraterrestrial solar irradiance at the sun-earth distance (solar constant) and D is the distance correction factor taken from the IGY Instruction Manual (Ref. A-5). The values used for $I_o(M)$ are 135.3 mW cm^{-2}, 428 Btu/hrft2, and 1.94 cal cm^{-2} min^{-1}; hence, SIM can be run for any of these units. The distance correction factor varies between $\pm 3.5\%$ from the mean output over a year period. This factor is contained in SIM as a look-up array/table selected according to day number.

The values for τ were originally calculated by Threlkeld and Jordan (Ref. A-6) for average atmospheric conditions consisting of a sea level condition, with a moderately dusty atmosphere, and amounts of precipitable water vapor representative of average values for the United States as a whole for each month (Ref. A-1). The values for τ are shown in Table A-1.

Table A-1 Average Values of Atmospheric Optical Depth (τ) and Sky Diffuse Factor (C)

Date	Optical Depth,	Sky Diffuse Factor, C
Jan. 21	0.142	0.058
Feb. 21	0.144	0.060
Mar. 21	0.156	0.071
Apr. 21	0.180	0.097
May 21	0.196	0.121
June 21	0.205	0.134
July 21	0.207	0.136
Aug. 21	0.201	0.122
Sept. 21	0.177	0.092
Oct. 21	0.160	0.073
Nov. 21	0.149	0.063
Dec. 21	0.142	0.057

The values for τ (from Table A-1) are contained in a look-up array, in SIM, depending upon day number. For day numbers other than those shown in Table A-1, interpolations are made.

Deviations in τ will result because atmospheric dust and water vapor content vary with geographical region. To take this into account, a parameter called the "Clearness Number" is introduced by Threlkeld-Jordan. The clearness number, CN, is defined as the ratio between the actual (measured) clearday normal incident direct solar irradiance, at any given location, and the calculated value using the basic/average optical depth values (along with a given relative air mass, Equation 18) shown in Table A-1; hence,

$$CN = \frac{I(\text{measured})}{I(\text{calculated})} \qquad (21)$$

The normal incident direct solar irradiance (Equation 18), is then multiplied by the CN; hence

$$I(cr) = (CN)\ I_o(d)e^{-\tau \sec\theta_o} \qquad (22)$$

Values for CN are shown in Figure A-3. It is recommended that these numbers be multiplied by a factor of 0.90.

Source: Ref. A-6

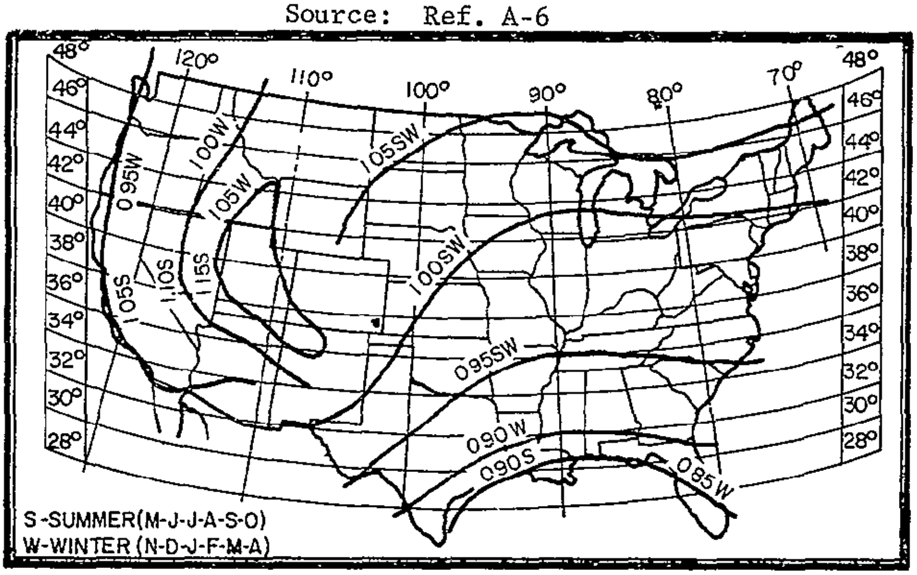

Figure A-3 Clearness Numbers of U.S. (It is recommended that these numbers be multiplied by a factor of 0.90.

The CN parameter is determined from Figure A-3 and is an input variable to SIM. If one has actual measurements of the normal incident direct solar beam irradiance, the CN can be calculated by:

$$CN = \frac{I(\text{measured})}{I_o(d)e^{-\tau \sec\theta_o}} \qquad (23)$$

where I_o has the same units as I(measured) and θ_o is calculated by the previously given equations. This was done for Waterton and Boulder, Colorado, for an extremely clear and dry day in December and for an average clear day in April. The December day analysis is particularly significant because solar spectrophotometer data established that the atmospheric dust content was nearly zero and the water vapor content was only 0.5 cm precipitable water (Ref. A-7); hence, it represented conditions of minimum atmospheric optical depth and a maximum clearness number. The analyses results are shown in Tables A-2 and A-3.

The mean of all the clearness numbers is 0.95 for Waterton and Boulder, compared to the 1.05 indicated in Figure A-3. This results because the original clearness numbers given by Threlkeld and Jordan were generated using a solar constant of 378 Btu/ft^2 hr, whereas the new value used in SIM is 428 Btu/ft^2 hr. This difference results in calculated values of the direct beam being lower by a factor of 0.9 relative to the original solar constant value. Therefore, the clearness number would be lower by a factor of 0.9. The comparable CN for Waterton and Boulder would then be 0.9 x 1.05, or 0.945. This CN agrees well with the values shown in Tables A-2 and A-3. If measured clearness numbers are not available, it is recommended that the standard clearness numbers be corrected by multiplying by 0.90. Because of the inherent variability of the clearness number due to variations in atmospheric water vapor, dust, and site elevation, measured clearness numbers should be used whenever possible.

The diffuse sky irradiance for a clear day on a horizontal surface, H(s)hcr, is calculated by Ref. A-2 as follows:

$$H(s)hcr = C \quad I(cr)/(CN)^2 \qquad (24)$$

where C is defined as the diffuse sky factor which is equal to the ratio of the diffuse horizontal irradiance divided by the normal incident direct solar irradiance. A comparison of the standard values (Table A-1) with measured values are shown in Tables A-2 and A-3. As can be seen, the measured values of C, i.e., C(M), are

Table A-2 Analysis Results of Atmospheric Parameters for April 15, 1974, Waterton, Colorado

I(M)	m	I(C)	CN(S)	CN(C)	H(s)M	H(s)C	H(s)C'	(C)S	C(M)
1.274	2.320	1.271	1.05	1.002	0.054	0.112	0.055	0.097	0.043
1.313	2.100	1.322		0.993	0.065	0.116	0.065		0.049
1.363	1.822	1.390		0.980	0.085	0.122	0.089		0.062
1.454	1.333	1.512		0.957	0.089	0.133	0.098		0.061
1.466	1.195	1.556		0.942	0.101	0.137	0.114		0.069
1.479	1.156	1.567		0.944	0.095	0.138	0.106		0.064
1.477	1.167	1.564		0.944	0.095	0.138	0.106		0.064
1.452	1.236	1.545		0.940	0.090	0.136	0.102		0.062
1.408	1.404	1.499		0.939	0.087	0.132	0.099		0.062
1.388	1.464	1.483		0.936	0.092	0.130	0.104		0.066
1.365	1.556	1.458		0.936	0.077	0.128	0.087		0.056
1.354	1.649	1.434		0.951	0.074	0.126	0.081		0.054
1.333	1.761	1.406		0.948	0.068	0.124	0.076		0.051
1.301	1.896	1.372		0.948	0.072	0.121	0.080		0.055
1.272	2.062	1.332		0.955	0.073	0.117	0.079		0.057
1.233	2.267	1.283		0.961	0.074	0.113	0.080		0.060

I(M) = Measured direct irradiance, cal cm^{-2} min^{-1}

m = relative air mass

I(C) = calculated direct irradiance

CN(S) = Standard Clearness Number,

CN(C) = Calculated Clearness Number,

H(s)M = Measured diffuse solar irradiance (horizontal)

H(s)C = Calculated diffuse solar irradiance

H(s)C' = Calculated diffuse solar irradiance using measured values

C(S) = Standard diffuse sky factor.

C(M) = Measured diffuse sky factor.

Table A-3 Analysis Results of Atmospheric Parameters for December 9, 1975, Boulder, Colorado

I(M)	m	I(C)	CN(S)	CN(C)	H(s)M	H(s)C	H(s)C'	C(S)	C(M)
1.315	2.420	1.417	1.05	0.928	0.058	0.073	0.067	0.057	0.044
1.324	2.360	1.429		0.926	0.055	0.074	0.063		0.041
1.334	2.310	1.439		0.927	0.057	0.074	0.065		0.042
1.340	2.270	1.447		0.926	0.060	0.075	0.070		0.045
1.347	2.240	1.454		0.927	0.059	0.075	0.069		0.044
1.352	2.210	1.460		0.926	0.060	0.076	0.069		0.044
1.356	2.190	1.464		0.926	0.055	0.076	0.063		0.040
1.361	2.180	1.466		0.928	0.053	0.076	0.062		0.039
1.366	2.180	1.466		0.932	0.053	0.076	0.061		0.039
1.368	2.180	1.466		0.933	0.055	0.076	0.063		0.040
1.352	2.220	1.458		0.927	0.065	0.075	0.076		0.048
1.336	2.330	1.439		0.931	0.063	0.074	0.072		0.047
1.308	2.510	1.399		0.935	0.062	0.072	0.070		0.047
1.272	2.830	1.337		0.952	0.052	0.069	0.056		0.040
1.226	3.290	1.252		0.979	0.039	0.065	0.041		0.032
1.123	4.170	1.105		1.016	0.034	0.057	0.034		0.031
1.073	4.860	1.002		1.071	0.028	0.052	0.024		0.026

This results in high values for the calculated diffuse using standard values of CN and C, H(s)C, compared to the measured values for CN and C that are used (Eq. 24) to calculate the diffuse irradiance H(s)C', a much closer agreement results. This agreement is generally 0.1 cal cm^{-2} min^{-1}, compared to the direct beam irradiance of approximately 1.0 to 1.5 cal cm^{-2} min^{-1}; hence, the relative agreement is only on the order of one percent or less. The agreement between the calculated diffuse irradiance (using the standard values of CN and C) and the measured is approximately 0.05 cal cm^{-2} min^{-1} (or 3.6 to 2.4%) which is not considered significant for a model of this type.

lower than the standard values, i.e., C(S). This is reasonable because the measurements were made at a high altitude, clear site, where the diffuse sky irradiance would be lower than those at sea level, for which the standard values were originally calculated.

The diffuse sky irradiance for clear days on a panel having a tilt angle of PT, is calculated by:

$$H(s)\,cr = C \quad I(cr)\left[\,1 + \cos\,(PT\,)\,/2\,\right] \tag{25}$$

The ground reflected irradiance H(r)cr is calculated by

$$H(r)cr = \rho_g \left[H(s)hcr + I(cr)\cos\theta_o\right]\left[1 - \cos\,(PT) \quad /2\right] \tag{26}$$

where ρ_g is the ground reflectivity.

For clear conditions, the total instantaneous irradiance on a panel H(p)cr is calculated by:

$$H(p)cr = H(d)cr + H(s)cr + H(r)cr \tag{27}$$

The total quantity of solar irradiance received on the panel integrated over the entire clear day is calculated by:

$$H(PI)cf = \int_{SRT}^{SST} H(p)cr\; dt. \tag{28}$$

This quantity is determined by first calculating sunrise and sunset times, and SST, respectively. The total day time is then divided into 31 increments with one increment always positioned at true solar noon. The instantaneous values of H(p)cr are next calculated at each of the 31 increments and then integrated, using the trapezoidal approximation, from SRT to SST to yield H(PI)cr. The discrete equation used is:

$$\int_{SRT}^{SST} H(p)cr\; dt = \Delta t \quad 1/2H(p)cr_1 + H(p)cr_2 + H(p)cr_1 + 1/2H(p)cr \tag{29}$$

where Δt is the time increment between each calculated H(p)cr. This time increment is a variable depending on day length and is calculated by:

$$t = \frac{SS - SR}{31} \tag{30}$$

1.3 <u>Total, Direct, and Diffuse Solar Irradiance for Cloudy Conditions</u> - The solar irradiance quantities for a cloudy day are calculated by the method developed by Kusuda (Ref. A-2), who based the method on analyses performed by Kimura and Stephenson (Ref. A-3). Kiumura and Stephenson analyzed 1967 Canadian data for observed solar irradiance with respect to the cloud cover data, type of cloud, and the calculated solar irradiance under a cloudless condition at the same solar time. Kusuda's method estimates a factor called the cloud cover factor (CCF) which is used to modify the solar irradiance for clear days with observed cloud cover data. The cloud cover data consists of major weather station observations of the amount of cloud cover on a scale of 0 to 10 and the type of clouds in four different layers. SIM uses Kusuda's basic method; however, the required cloud cover input data was changed from the detailed weather station observations to a more readily available parameter called "mean sky cover" available in the *National Climatic Atlas*. The details of these modifications will be discussed in the following paragraphs. The basic equations for direct, diffuse, and total solar irradiance for cloudy conditions will be presented first. The definition of the CCF, Cloud Cover (CC) and other cloudy condition parameters used to modify the clear day solar irradiance are defined and discussed in the following paragraphs.

The direct solar irradiance on a horizontal surface under a cloudy sky H(d)hcd is calculated by:

$$H(d)hcd = H(d)hcr \;\; K \; (1 - CC/10) \tag{31}$$

where H(d)hcr is the direct solar irradiance on a horizontal panel under clear skys, and K and CC are cloud cover modifiers based upon observations and analyses made by Kimura and Stephenson (Ref. A-3). The parameter K is calculated by:

$$K = X/(C + X) + (P - 1)/(1 - Y) \tag{32}$$

where C is the diffuse sky factor (as defined previously, X = sin ϕ (solar altitude angle), P is defined as the "cloudless sky factor", and:

$$Y = 0.309 - 0.137X + 0.394\ X^2 \tag{33}$$

The parameter P is given (Ref. A-2 and A-3) along with parameters (to be used later) Q and R in Table A-4.

Table A-4 Values of Cloudy Day Parameters P, Q, and R

Season	P	Q	R
Spring	1.06	0.012	-0.0084
Summer	0.96	0.033	-0.0106
Autumn	0.95	0.030	-0.0108
Winter	1.14	0.003	-0.0082
Ave.	1.028	0.0195	-0.0095

As can be seen in Equation 31, the product K(1-CC/10) is the modifier that adjusts clear day horizontal solar irradiance to a cloudy day. This was determined by Kimura and Stephenson from actual observations of a year of data. The parameter is determined by

$$CC = TCA - 0.5\ C' \tag{34}$$

where TCA is the total cloud amount, and C' is the sum of the cover of cirrus, cirrostratus, and cirrocumulus clouds. The units of CC, TCA, and C' are tenths (0 to 10). The method developed by Kimura and Stephenson uses detailed weather station observations; however, a modification was made to this method to make SIM more easily used. The first modification was to assume that under normal conditions the amount of cirrus type clouds make up approximately 25% of the total cloud amount; therefore, Equation 34 becomes:

$$CC = 0.875\ TCA \tag{35}$$

The value for TCA can be obtained from the *National Climatic Atlas**. This allows any geographical site in the U.S. to be considered on a monthly basis.

The direct solar irradiance on a panel [H(d)cd] for cloudy conditions is calculated by:

$$H(d)cd = H(d)cr\ [H(d)hcd/H(d)hcr] \tag{36}$$

* "Mean Sky Cover, Sunrise to Sunset, Monthly and Annual", *National Climatic Atlas*, p. 77.

where H(d)hcd was calculated by Equation 31, and H(d)cr is the direct solar irradiance on the panel under clear skys (Eq. 2). H(d)hcr is the irradiance on a horizontal surface under clear day conditions,

$$H(d)hcr = I(cr)\cos\theta_o \tag{37}$$

where I(cr) and θ_o were defined in section 1.2. Hence, the direct solar irradiance on a panel for cloudy conditions is calculated by multiplying the direct solar irradiance on the panel for clear days by the ratio of the horizontal solar irradiance on a cloudy day divided by the horizontal solar irradiance on a clear day.

The diffuse solar irradiance on a horizontal surface for cloudy conditions [H(s)hcd] is:

$$H(s)hcd = H(t)hcr\ [CCF-K(1-CC/10)] \tag{38}$$

where H(t) hcr is the total solar irradiance on a horizontal surface for clear days (K is given by Eq. 32) and CCF is the cloud cover factor. The cloud cover factor is :

$$CCF = P + Q\ (CC) + R\ (CC)^2 \tag{39}$$

where P,Q,R, and CC have been defined previously. The total solar irradiance on a horizontal surface for clear days is :

$$H(t)hcr = H(d)hcr + H(s)hcr \tag{40}$$

where H(d)hcr and H(s)hcr have been previously defined.

The diffuse solar irradiance on a panel for cloudy conditions H(s)cd is :

$$H(s)cd = H(s)hcr\ \ H(s)hcd/H(t)hcr \tag{41}$$

The ground reflected irradiance for a cloudy day H(r)cd is:

$$H(r)cd = \rho_g\ [H(d)hcd + H(s)hcd]\ [1-\cos(PT)]/2 \tag{42}$$

The total instantaneous solar irradiance on a panel for a cloudy day H(p)cd is calculated by:

$$H(p)cd = H(d)cd + H(s)cd + H(r)cd \tag{43}$$

The total integrated daily solar irradiance [H(PI)cd] is calculated similarly as shown in Equation 28 (also see Table A-11).

1.4 <u>Calculation of Daily, Integrated, Solar Irradiance</u> - In order to calculate the daily, and thereby the monthly and yearly integrated solar irradiance, a knowledge of the clear versus cloudy conditions during the day is required. This information is obtained from the *National Climatic Atlas* given as the percentage sunshine per month.

SIM uses the percent sunshine parameter to calculate that portion of the day that is clear and that portion that is cloudy. For example, if the percent sunshine is 60%, 60% of the total daylight hours are calculated on a clear basis and forty percent of the day is calculated on a cloudy basis. For the cloudy day portion, the cloud cover parameter is set equal to 10. This condition closely corresponds to the conditions represented by the percent sunshine data.

The percent sunshine data were taken when clear conditions existed (i.e., unobstructed direct solar beam). The data for cloudy conditions were taken when the direct solar beam was almost totally obstructed by clouds. These cloudy conditions are represented by the cloudy day condition equations if the CC is equal to 10. By setting CC equal to 10, this reduces the direct solar beam to 0.0 (Eq. 31) which corresponds most closely to the sunshine switch data. The remaining irradiance is that made up of diffuse solar irradiance given in Equation 38 and 41. Since CC = 10.0, Equation 38 reduces to:

$$H(s)hcd = H(t)hcr\ (CCF) \qquad (44)$$

In addition, the equation for CCF (Eq. 39) reduces to:

$$CCF = P + 10Q + 100R \qquad (45)$$

for the values of P, Q, and R given in Table A-4. The CCF parameter results are given in Table A-5.

Table A-5 Values for Cloud Cover Factor

Season	CCF
Spring	0.34
Summer	0.23
Autumn	0.17
Winter	0.35
Average*:	0.273

*Using average values of P, Q, and R

An inspection of Equation 44 shows that the CCF is the parameter that represents the ratio of diffuse solar irradiance on a horizontal surface during cloudy conditions (for conditions of CC = 10) to the total solar irradiance on a horizontal surface during clear conditions. In reality this function is dependent upon many variables such as sun angle, cloud conditions, time of day, etc., in addition to the seasonal variation (Table A-5). Equations to describe this complex variable are not available; therefore, SIM uses the average values of P, Q, R, and CCF shown in Tables A-4 and A-5. This is not a serious limitation because the diffuse solar irradiance constitutes a much smaller part of the total solar irradiance than the intense direct solar beam. Hence, uncertainties in the diffuse component impact uncertainties in the total solar irradiance much less.

Test runs of SIM were made using both the seasonal P, Q, and R's and the average P, Q, and R's. In terms of yearly integrated solar irradiance, the difference between the results was insignificant. Therefore in order to simplify SIM, the average values of P, Q, and R are used in SIM.

The actual positioning of the cloudy and clear portions of a day has a significant impact on the total daily solar irradiance, as shown in later sections. For example, if the cloudy portion of the day is positioned around noon, the total daily irradiance will be reduced more than if the cloudy portion is positioned in the morning or afternoon. SIM has the capability of dividing a day up into fractions. Each of these fractions can be calculated on a clear or cloudy basis. This allows the cloudy day portion to be evenly distributed throughout the day. If actual data are available, the cloudy portion can be positioned according to actual knowledge. If no actual data are available, SIM should be used on an even distribution of cloudy portion basis. This distributes the effects of clouds equally for all levels of solar irradiance. As discussed in later sections, when this was done the SIM results agreed most closely with historical data.

SIM can divide the day up into as many as 10 fractional parts (see Table A-6).

Table A-6 Basic Definition of Day Parameters

Day Definition Matrix											
Day Part	1	2	3	4	5	6	7	8	9	10	One Day
Day Fraction	0.XX	0.XX	0.XX	0.XX	0.XX	0.XX	0.XX	0.XX	0.XX	0.XX	1.0
Total Cloud Amount (TCA)	XX.0	XX.0	XX.0	XX.0	XX.0	XX.0	XX.0	XX.0	XX.0	XX.0	

Each day part is assigned a day fraction and a total cloud amount (TCA). The day fraction can have as many significant figures as desired. Each day part is calculated in sequential order from 1 to 10. The day fraction determines the length (time) of the day part because the day fraction is multiplied by the total number of calculation points (31) to determine the number of calculation points (rounded off to the nearest integer number). Since the total number of 31 calculation points is equivalent to the total day length, the number of calculation points determined by the day fraction represents the fractional day length of the day part. The day fraction is a number greater than zero and less than 1.00. The sum of all day fractions must equal 1.00. Due to the limit of 31 calculation points and the computer round-off routine, the day fraction has to be greater than 0.0164 and less than 0.984. If the day fraction is less than 0.0164, the computer will conclude the day fraction is 0.00. If it is greater than 0.9984, the computer will conclude the day fraction is 1.00.

The total day fraction (the sum of all day parts) calculated on a clear basis (TCA = 0) is determined by the percent sunshine data from the *National Climatic Atlas* . For example, if the percent sunshine is 60%, the sum of the day fractions (having a TCA = 0) should equal 0.60. The remainder when calculated on a cloudy (TCA = 10) basis would equal 0.40.

As discussed previously, the positioning of the cloudy day parts can be very significant in terms of the integrated daily solar irradiance. In addition, if the cloudy day parts are positioned in the afternoon, this would have a significant impact on the daily and instantaneous solar irradiance received on a solar cell panel oriented toward the east or west. The panel oriented east would receive much more energy than the panel oriented west. Therefore, knowledge available (one source is the National Weather Service) concerning the time(s) of occurrence of clouds should be used to define a day. The following paragraphs will discuss examples of day definitions for a simple clear day, a simple "fixed" partly cloudy day, a complex "fixed" partly cloudy day, and an "even" partly cloud day.

The most simple day definition matrix is that of a 100% clear day (see Table A-7).

Table A-7 Day Definition of a Clear Day

Day Part	1
Day Fraction	1.0
TCA	0

The simple partly cloudy day consists of a day where the clear portion occurs continuously over a given portion of the day and then the cloudy portion exists the remainder of the day. Hence, this type of day only consists of two parts. The length of each part is determined by the percent sunshine data and subsequently the day fraction. For example, assume that a site has a percent sunshine of 60% with the sunshine occurring the first portion of the day. The day definition matrix for such a day is shown in Table A-8.

Table A-8 Day Definition of a Simple "Fixed" Partly Cloudy Day

Day Part	1	2
Day Fraction	0.60	0.40
TCA	0	10

If the data are available for the specific times of occurrences of cloud cover, a complex "fixed" partly cloudy day can be defined to closely match the real data. A hypothetical example is shown in Table A-9.

Table A-9 Day Definition of a Complex "Fixed" Partly Cloudy Day

Day Part	1	2	3	4	5	6	7	8	9	10
Day Fraction	0.1	0.08	0.2	0.08	0.08	0.08	0.1	0.08	0.08	0.12
TCA	10	0	10	0	0	0	10	0	0	0

Note that the sum of the day fractions is equal to 1.00 and the sum of the clear (TCA = 0) parts day fraction equal 0.6 which represents the sites percent sunshine.

If data are not available for the time occurrence of clouds, the most reasonable representation of clear and cloudy portions would be an "even" distribution which positions the clear and cloudy parts evenly throughout the day. Hence, the effects of clouds are equally distributed over all levels of solar irradiance. Statistically, over monthly and yearly periods of time, this type of day definition would be the one most likely to represent real conditions and give the best estimates of integrated (monthly, yearly) solar irradiance. The day definition is formulated by considering that five parts of the day will be clear and five parts cloudy. These parts are to be alternated throughout the day to give an "even" distribution. Hence, day part 1 would be cloudy, day part 2 would be clear, etc. The length (day fraction) of the clear and cloudy day parts is determined (as discussed previously) by the site's percent sunshine. For example, if a site has a percent sunshine of 60%, the day fraction for each of the five day parts would be 0.60/5 or 0.12. The cloudy day fractions would be 0.40/5 or 0.08. The resultant day definition matrix is shown in Table A-10.

Table A-10 Day Definition of an "Even" Partly Cloudy Day

Day Part	1	2	3	4	5	6	7	8	9	10
Day Fraction	0.12	0.08	0.12	0.08	0.12	0.08	0.12	0.08	0.12	0.08
TCA	0	10	0	10	0	10	0	10	0	10

Other day definitions can be formulated by using the *National Climatic Atlas* data for mean sky cover which is equivalent to the TCA. For example, instead of assuming that the TCA is zero during the clear portions of the day, a mean sky cover (as long as it is less than 10.0) can be used. Representing the clear portion of the day by TCAs greater than zero results in a reduction of the direct solar irradiance; therefore, the total and integrated solar irradiance. This would represent a "worst" case condition. If a day is defined by a TCA equal to the mean sky cover for the entire day with no TCAs of 10, it represents a continuous partly cloudy condition throughout the day.

Because SIM uses monthly percent sunshine and mean sky cover data from the *National Climatic Atlas*, the output of SIM is most representative of the monthly integrated and yearly integrated solar irradiance. However, the instantaneous and daily SIM calculation would be representative of a "mean" day for a given month. In the real case, there are days that are totally clear and days that are totally cloudy. However, over a period of one month, SIM will closely simulate the total clear portion and total diffuse portion of the month. The total integrated monthly solar irradiance and the yearly integrated solar irradiance are determined by simply summing the daily values over each month. Table A-11 summarizes the basic equations and terminologies used in the SIM.

Table A-11 SIM Equations and Definitions

H(p) = total instantaneous irradiance on panel

H(d) = direct instantaneous irradiance on panel

H(s) = diffuse instantaneous irradiance on panel

H(r) = reflected instantaneous irradiance on panel

H(p) = H(d) + H(s) + H(r)

H(d)cr = direct irradiance on panel, clear day

$= I(cr)\mathrm{Cos}\theta$

θ = solar incident angle

I(cr) = normal incident direct irradiance, clear day

$= (CN)I_o(d)e^{-\tau\sec\theta_o}$

θ_o = solar zenith angle

CN = clearness number

= I(measured)/I(calculated)

τ = optical depth

$I_o(d)$ = extraterrestrial solar irradiance on a given day number(d)

$= I_o(M)\ (D)$

$I_o(M)$ = solar constant

D = Earth-Sun distance correction

H(s)hcr = diffuse irradiance on horizontal surface, clear day

$= C\ I(cr)/CN^2$

C = diffuse sky factor = diffuse horizontal/normal incident direct polar irradiance.

H(d)hcr = direct irradiance on horizontal panel, clear day

$= I(cr)\mathrm{Cos}\theta_o$

H(t)hcr = total instantaneous irradiance on horizontal panel, clear day

$H(t)hcr = H(d)hcr + H(s)hcr$

H(s)cr = diffuse irradiance on panel, clear day

$H(s)cr = (C)I(cr)\ [1 + \cos\ (PT)]/2$

PT = panel tilt angle above horizon

H(r)cr = reflected ground irradiance on panel, clear day

$H(r)cr = \rho_g \left[H(s)hcr + I(cr)\cos\theta_o\right] [1-\cos(PT)]/2$

ρ_g = ground reflectivity

H(p)cr = total instantaneous irradiance on panel, clear day

$H(p)cr = H(d)cr + H(s)cr + H(r)cr$

H(PI)cr = daily integrated solar irradiance on panel clear day

$$H(PI)cr = \int_{SRT}^{SST} [H(p)cr]\ dt$$

SRT = sunrise time

SST = sunset time

H(d)hcd = direct irradiance on horizontal panel, cloudy day

$H(d)hcd = [H(d)hcr]\ K\ (1 - CC/10)$

$K = X/(C+X) + (P-1)/(1-Y)$

$X = \sin\phi$

ϕ = solar altitude angle

$P = 1.028$

$Y = 0.309 - 0.137X + 0.394\ X^2$

CC = Cloud Cover

Table A-11 - SIM Equations and Definitions - Concluded

CC = 0.875 TCA

TCA = Total cloud amount, mean sky cover

H(d)cd = direct irradiance on panel, cloudy day

H(d)cd = H(d)cr [H(d)hcd/H(d)hcr]

H(s)hcd = diffuse irradiance on horizontal surface, cloudy day

H(s)hcd = H(t)hcr [CCF - K(1-CC/10)]

CCF = Cloud cover factor

$CCF = P + Q\ (CC) + R(CC)^2$

Q = 0.0195

R = -0.0095

H(s)cd = diffuse irradiance on panel, cloudy day

H(s)cd = H(s)cr [H(s)hcd/H(s)hcr]

H(r)cd = ground reflected irradiance for cloudy day

$H(r)cd = \rho_g\ [H(d)hcd + H(s)hcd]\ [1-COS(PT)]/2$

H(p)cd = total instantaneous irradiance on panel, cloudy day

H(p)cd = H(d)cd + H(s)cd + H(r)cd

H(PI)cd = daily integrated solar irradiance on panel, cloudy day

$$H(PI)cd = \int_{SRT}^{SST} [H(p)cd]\ dt$$

3. SOLAR ARRAY MODEL

The baseline solar array design consists of a number of 1.219 x 1.219-m subarray segments. The solar array model determines the power output of the total solar by simply summing the power of individual subarray segments. The basic characteristics of the 1.219 x 1.219-meter subarray, such as the temperature coefficient and the power output at a specific temperature (60°C), were derived from the specifications for the Solarex cell no. 2391 shown in Table A-12.

Table A-12 Solar Cell Characteristics

Current density (short circuit)	28.77 mA/cm^2
Voltage (open circuit)	0.568 V
Current density (at maximum power)	24.72 mA/cm^2
Voltage (at maximum power)	0.457 V
Maximum power density	11.3 mW/cm^2
Fill factor	0.69
Temperature coefficients:	
Voltage (open circuit)	-2.04 mV/°C
Current (short circuit)	+20 $\mu A/cm^2$ -°C
Power density	-0.039 mW/cm^2 - °C
Cell diameter	2.25 in.
Measurements made at: Temperature = 28°C Air Mass = 1 Insolation = 100 mW/cm^2	

The peak power output for the 1.219 x 1.219-meter subarray was specified initially to be at least 70 watts at an intensity of 100 mW/cm^2 and 60°C. Later information supplied from LeRC indicated that the power output per subarray could be as high as 100 watts. Based on this information, the basic subarray was modeled to accept the available power at 60°C as a variable parameter. The range of this procedure was selected for the sensitivity analysis as follows:

Worst case = 70 W/subarray

Nominal = 85 W/subarray

Maximum = 100 W/subarray

Each power level has a unique temperature coefficient based on the solar cell characteristics (derivation shown in Appendix B).

The output power of the subarray (and therefore the total solar array) is sensitive to temperature. Thus, provisions have been made in the solar array model to allow for time varying temperature and possible temperature gradients throughout the solar array. The solar array was divided up to 10 temperature zones. Each zone is specified as a percentage of the total array area. The temperature of the respective zones can be altered in 1/2-hour increments up to a maximum of 31 increments.

The input parameters necessary for the solar array model are:

(1) Number of 1.219 x 1.219-meter subarrays, M;

(2) Time-varying solar irradiance on the solar array, h_x. (This parameter is an output from the solar irradiance model;)

(3) The temperature of each zone, T_{ij} where i = temperature zone number (up to a maximum of 10), and j = temperature array number (given in 1/2-hour increments up to a maximum of 31);

(4) The percentage of the total solar array area that each temperature zone occupies, A_{pzi};

(5) The number of temperature zones, Z (up to a maximum of 10);

(6) Coefficient of change in power available per unit temperature, γ. (see Appendix B for derivation);

(7) The power output of the subarray, P_{S60}, at solar array temperature of $60^{o}C$ and standard solar intensity of $100\ mW/cm^2$.

(8) Solar degradation factor, F_d. This factor accounts for dust, dirt, etc. that accumulates on the array and is a function of time (e.g., 0.2%/month).

(9) Daylight duration, T_D (output from the solar irradiance model).

The total solar array power output is constructed from the subarray level. The solar array power output is as follows:

(1) Subarray power output at 60°C and as a function of time (accounting for degradation factor),

$$P_{S60_t} = P_{S60}\left(\frac{100 - F_d}{100}\right)_{MS} \tag{44}$$

where, MS = month-(month-of-start)

For example, if the run is started in January, month-of-start = 1. Note that if the run is started in January; the P_{S60_t} for June is,

$$P_{S60_t} = P_{S60}\left(\frac{100 - F_d}{100}\right)_5 \tag{45}$$

(2) Power output of an individual subarray (in a particular temperature zone) as a function of time, P_{SAMij}.

$$P_{SAMij} = \left[P_{S60_t} + \left(t_{ij} - 60\right)\right] \frac{h_x}{H_{STD}} \tag{46}$$

where i = temperature zone number

j = temperature array number

(3) The average power output from a subarray over the daylight period (in a given temperature zone i) is

$$\bar{P}_{SAMi} = \frac{1}{T_D} \sum_{j=1}^{31} P_{SAMij} \times time_j \tag{47}$$

(4) Total average output power from the solar array,

$$P_{SA} = \sum_{i=1}^{Z} \left(\bar{P}_{SAMi}\right)(M)\left(A_{pzi}\right) \tag{48}$$

(5) Total daily energy from the solar array, E_{SA}.

$$E_{SA} = P_{SA} T_D \tag{49}$$

(6) Array size, A_{SIZE}

$$A_{SIZE} = 1.4864 \text{ M (meters)}^2$$

4. ELECTRICAL LOAD MODEL

The primary function of the electrical load model (ELM) is to convert electrical load profiles into a form useful to the energy balance model. Basically this is to determine the daytime and nighttime average load power and calculate the total daily (24 hr) energy required by the load. For example, assume that the daily total load profile shown in Figure A-4 is used as an input. This input is listed in Table A-13.

Depending on the time of year, the daylight and nighttime hours are determined and the average day and night power is calculated. For the load profile given in Table A-13 and for March 25, 1976, the results are the following:

Sunrise: 6:00

Sunset: 18:12

Average day power: 1.75 kW

Average night power: 1.04 kW

Total energy: 36.01 kWh

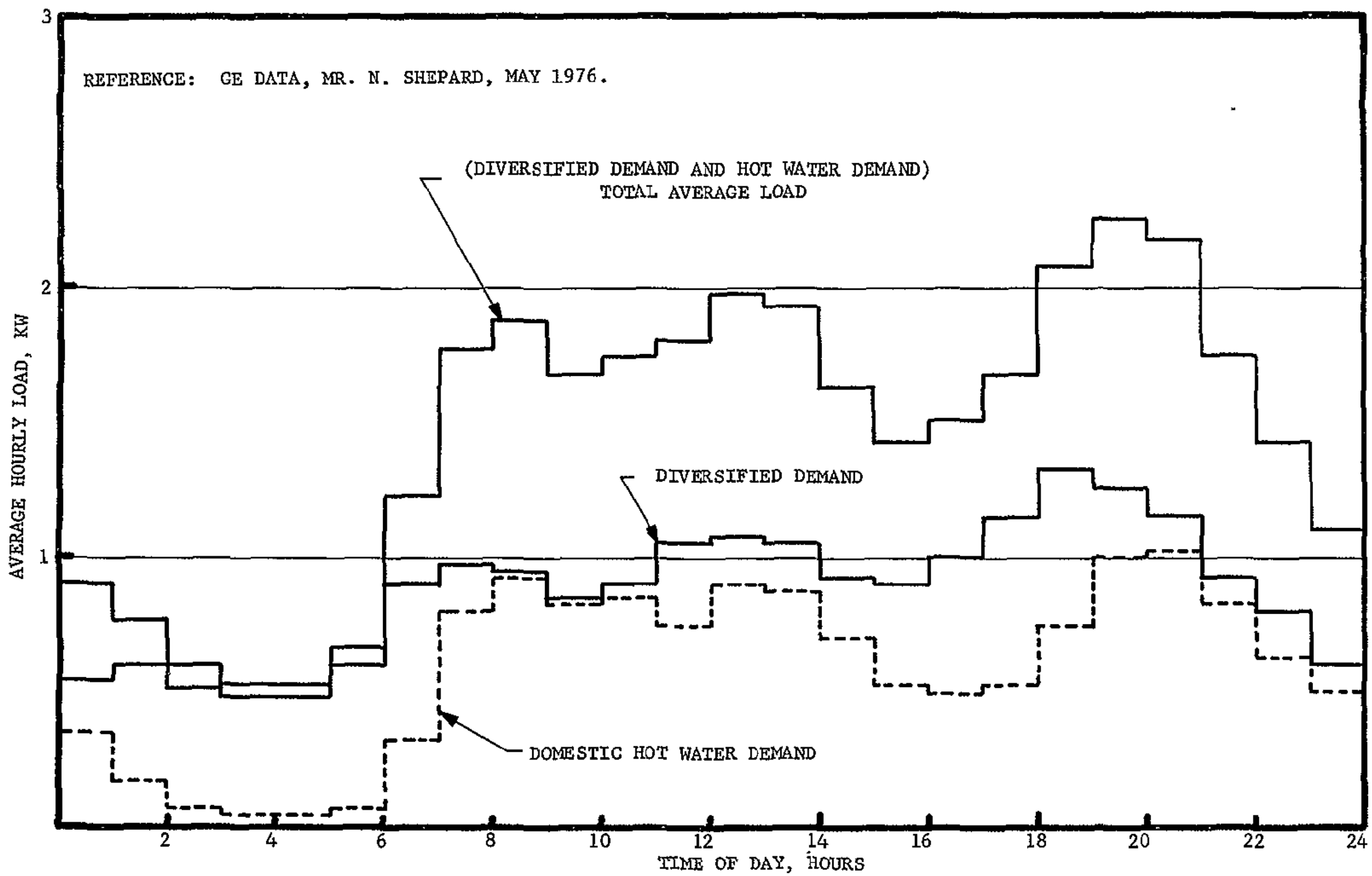

Figure A-4 Daily Load Profiles for Cleveland

Table A-13 Average Hourly Load kW_e

Hour of Day, (LST)*	Daily Total Load Profile
0 to 1	0.9
1 to 2	0.775
2 to 3	0.6
3 to 4	0.53
4 to 5	0.53
5 to 6	0.675
6 to 7	1.225
7 to 8	1.775
8 to 9	1.875
9 to 10	1.675
10 to 11	1.75
11 to 12	1.8
12 to 13	1.975
13 to 14	1.925
14 to 15	1.625
15 to 16	1.425
17 to 18	1.5
18 to 19	1.675
19 to 20	2.075
20 to 21	2.25
21 to 22	2.175
22 to 23	1.75
23 to 24	1.425
	1.1
	35.01 kWh_E
	Total Energy Used By Load Per Day

*Local Standard Time

It can be shown that the same load profile, the average day and night power can change significantly as both the daylight duration and sunrise and sunset times change throughout the year. For example, on June 21, 1976, the results for the same load profile are:

Sunrise: 4:37

Sunset: 19:26

Average night power: 1.08 kW

Average day power: 1.68 kW

Total energy: 36.01 kWh

Even though the total daily energy remains constant, the load distribution between day and night affects the system operation. (The effects of the per day load distribution is discussed in the energy balance section.) The program does not require hourly load profiles such as the one used above. The type of input used by the ELM allows for considerable flexibility of the input load profile. The input profile can be constant, yearly, daily, or in any increments down to 0.5.hour. These types of load profiles can be divided into two categories: (1) load profiles provides consisting of only one or less data points per day; thus, load time increments $\geq$ 24 hours; and (2) load profiles consisting of provides more than one data point per day; thus, load time increments $<$ 24 hours. An example of the first type of load profile is shown in Figure A-5. The second type of profile used in the previous example is depicted in Figure A '

If the time increments of the load profile are greater than 24 hours, then for a given 24 hour day, the input load $\left(P_E\right)$ is equal to the power required by the average daily load, $\left(P_L\right)$ and the day load $\left(P_{ED}\right)$, and night load $\left(P_{EN}\right)$ are equal. Therefore, $P_E = P_L = P_{EN} = P_{ED}$.

For the condition where the load profile is given in increments less than 24 hours, the average day power (P_{ED}) and the average night power (P_{EN}) are determined as follows:

$$P_{ED} = \frac{1}{T_D}\left(\sum_{i=1}^{N} P_{ei} t_i\right) \tag{50}$$

where, P_{ei} = power during the ith time increment,

and, t_i = time duration of the ith increment.

N = number of time increments in daylight period,

T_D = day duration

Likewise,

$$P_{EN} = \frac{1}{T_N} \sum_{j=1}^{m} P_{ej} t_j \tag{51}$$

where. m = number of time increments in nighttime period.

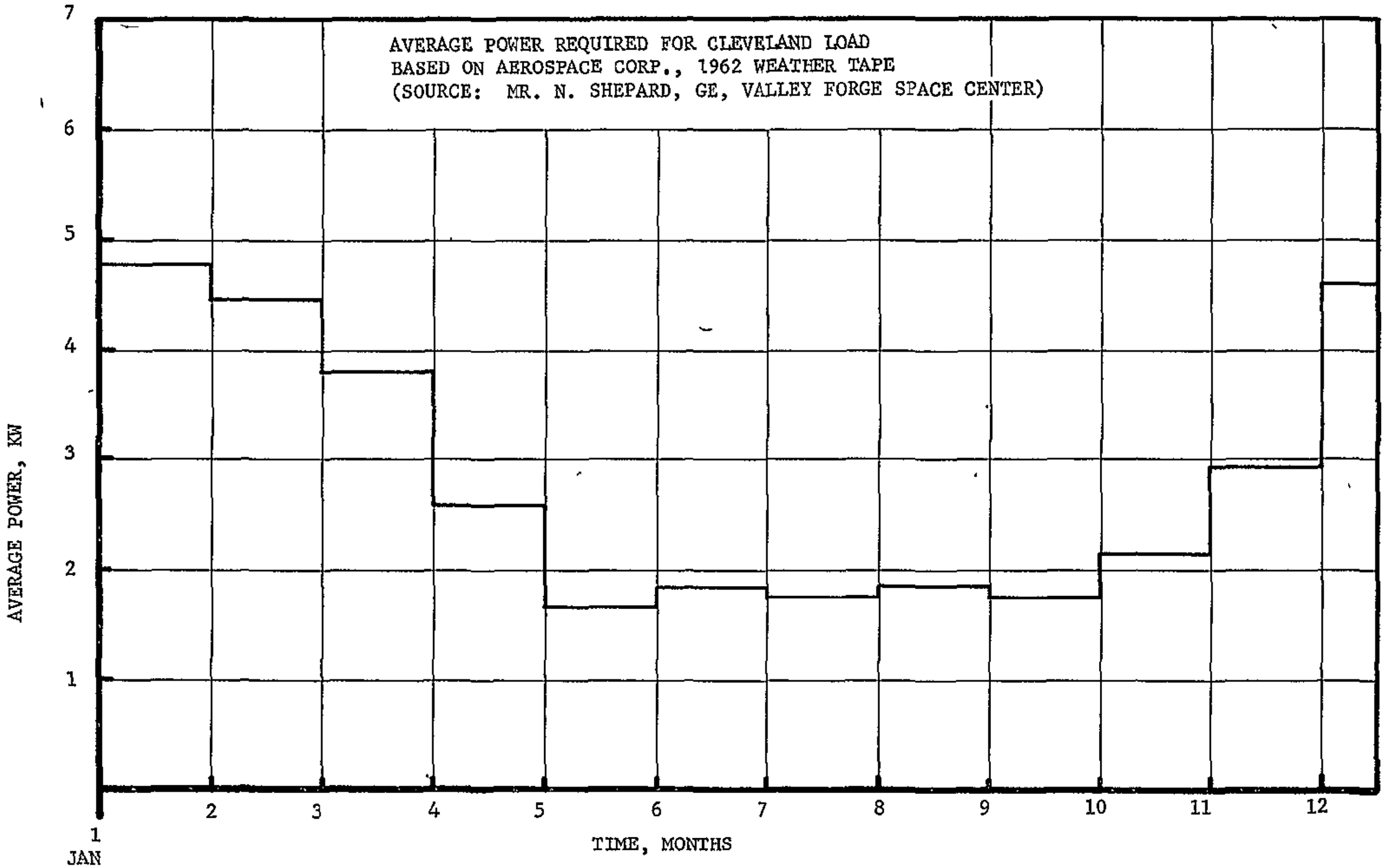

Figure A-5 Monthly Load Profile

The average power $\left(P_L\right)$ for the 24-hour day is determined as,

$$P_L = \frac{P_{EN}T_N + P_{ED}T_D}{T_D + T_N} \tag{52}$$

The total energy $\left(E_L\right)$ required by the load per day is,

$$E_L = P_L \left(T_D + T_N\right) \tag{53}$$

5. ENERGY BALANCE MODEL

There are two basic approaches in formulating a math model of an energy demand-type system. One approach is to prepare an equivalent electrical circuit containing voltage and current sources and discrete devices. The resulting model is usually a set of independent equations. If the system consists of linear elements, the equations can be easily solved by matrix methods. If it has non-linear devices, its solution is via iterative or numerical techniques. The other approach to modeling a physical system is to express it in a power flow representation. This approach is best suited for a system containing power sources and energy storage devices where a sustained operation depends on satisfying at least an energy balance condition.

In a solar array/battery system, the energy balance condition is defined to mean that the total energy available from the solar array (E_{SA}) is exactly equal to the energy required to recharge the battery (E_B) and the energy required by the system electrical load including equipment losses (E_{LL}). That is,

$$E_{SA} = E_B + E_{LL} \qquad (54)$$

If the solar array has sufficient capability,

$$E_{SA} > E_B + E_{LL} \qquad (55)$$

and the battery is expected to be fully recharged before the end of the sunlight period. If the solar array has insufficient output,

$$E_{SA} < E_B + E_{LL} \qquad (56)$$

and the battery would continually deplete its energy in each successive charge/discharge operation.

A math model based on the energy balance expression can be easily defined for any power system. An added advantage of this approach is that all energy dissipation elements (i.e., losses) as well as power reduction factors can be expressed as lumped parameters. Each of these parameters can be treated as a constant or a variable. All basic quantities involved in a given system can be mathematically related to each other in one equation.

For a terrestrial based power system with utility back-up, it is not necessary that the energy balance condition always be met or exceeded by the solar array power output alone. If the PST power system has insufficient capacity to meet a given load requirement, the utility power will supply the demand. The total system energy balance is expressed as:

$$E_{SA} + E_U = E_B + E_{LL} \tag{57}$$

where, E_{SA} = Available solar array energy

E_U = Utility energy required by loads

E_B = Energy required to charge battery

E_{LL} = Energy consumed by load

The conceptual operation of the energy balance model is to compare the energy needed to charge the battery plus the energy used by the load to the energy available from the solar array. All energy losses in the power system are accounted for by component level efficiency factors. The utility energy used is the net difference between the energy required for the load and the solar array energy available or,

$$E_U = \left(E_B + E_{LL}\right) - E_{SA} \tag{58}$$

When the result is positive utility power is required to supply the load demand. If E_U is negative, or zero the PST system is supporting 100% of the residential load.

5.1 Derivation of Energy Balance Model

For a detailed derivation of the energy balance model, the individual terms of the energy balance equation can be expressed as the product of an average power and a time increment or,

$$\left(P_{SA}\ T_D\right) + E_U = \left(P_{EN}\ T_N\right) + \left(P_{ED}\ T_D\right) \tag{59}$$

where, P_{SA} = Average solar array power output over daylight period

T_D = Daylight duration

E_U = Utility energy required

P_{EN} = Average nighttime load power

T_N = Night duration

P_{ED} = Average daytime load power

The utility energy required is derived from the comparison of the solar array energy $\left(P_{SA}T_D\right)$ to the energy used by the load (terms on the right-hand side of eq. 51). The utility energy term could be expanded into a power-time product; however, it is not necessary to define these quantities since only the lumped utility energy term is used in the energy balance model.

The nighttime energy expressed in Equation 51 as $P_{EN}T_N$ must be provided by the battery and/or utility. If the PST power system was 100% efficient, $P_{EN}\ T_N$ would be the required amount of stored energy to achieve energy balance without utility power. However, when system losses are accounted for, the solar array must supply more energy than necessary for the load alone. For example, the energy efficiency of a lead acid battery is typically 70%. Hence, the energy required from the solar array to charge the battery is,

$$E_B = \frac{P_{EN}\ T_N}{0.7}$$

where, E_B = Solar array energy required for the battery

The battery is not the only system loss element. Figure A-6 shows a typical simplified block diagram and the associated power flow diagram for an EPS configuration. The power flow diagram shows the elements between the load bus and the solar array power output, P_{SA}. Thus, the solar array energy that must be allocated for the night demand is,

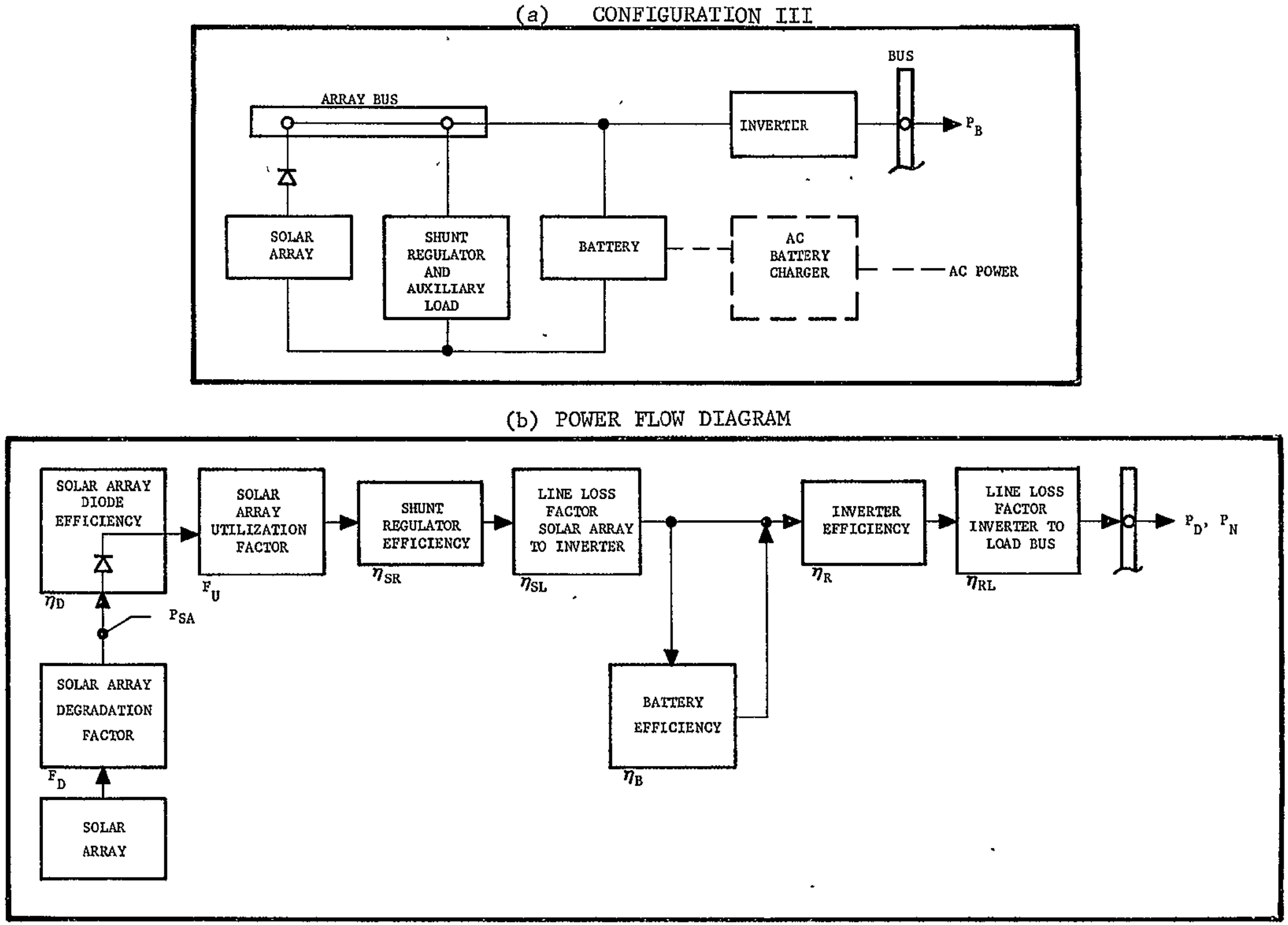

Figure A-6. Simplified Configuration III EPS Block Diagram (a) and Power Flow Diagram (b)

$$E_B = \frac{P_{EN} T_N}{\eta_D F_U \eta_{SR} \eta_{SL} \eta_B \eta_R \eta_{RL}} \tag{60}$$

where, η_D = Solar array diode efficiency

F_U = Solar array utilization factor

η_{SR} = Shunt regulator efficiency

η_{SL} = Line loss factor, solar array to inverter

η_B = Battery watt-hour efficiency

η_R = Inverter efficiency

η_{RL} = Line loss factor, inverter to load bus

The efficiency terms in the denominator of Equation 52 can be lumped together as,

$$X_1 = \eta_D F_U \eta_{SR} \eta_{SL} \eta_B \eta_R \eta_{RL}$$

For convenience the X_1 term is identified as the nighttime efficiency factor. As a result, the nighttime energy requirement can be expressed as,

$$E_B = \frac{P_{EN} T_N}{X_1}$$

Similarly, the daytime energy required is,

$$E_{LL} = P_{ED} T_D$$

where, P_{ED} = Average daytime power

T_D = Daylight duration

In order that the solar array delivers the necessary load power, the system losses must be included. For example, the inverter specified for the PST has a nominal average efficiency of 70%. If this was the only component in the system, the average solar array power necessary would be,

$$E_{LL} = \frac{P_{ED}\ T_D}{0.7}$$

The power flow diagram in Figure A-6 shows all energy loss elements in a typical EPS configuration (Configuration III). As the power flow sequence is analyzed from the load bus to the solar array output, all power loss (including line loss) elements are encountered. The power loss of each element is accounted for with component level efficiency factors.

The lumped system efficiency is the product of the individual component efficiencies. Therefore (from fig. A-6) the day power required from the solar array is,

$$E_{LL} = \frac{P_{ED}\ T_D}{\eta_D\ F_U\ \eta_{SR}\ \eta_{SL}\ \eta_R\ \eta_{RL}} \tag{61}$$

The lumped efficiency factor becomes,

$$X_2 = \eta_D\ F_U\ \eta_{SR}\ \eta_{SL}\ \eta_R\ \eta_{RL}$$

thus,

$$E_{LL} = \frac{P_{ED}\ T_D}{X_2}$$

The battery efficiency is not included in the day power efficiency because the load power is supplied directly from the solar array (the battery is charging at this time). The X_2, efficiency can only occur under favorable sunlight conditions, thus the term daytime efficiency is applied.

The terms for the energy balance comparison are therefore,

$$P_{SA}T_D + E_U = \frac{P_{EN}T_N}{X_1} + \frac{P_{ED}T_D}{X_2} \tag{62}$$

For an analysis of the PST power system capability, E_U is set equal to zero. The result is three primary quantities for evaluation: $P_{SA}T_D$, $P_{ED}T_D$, and $P_{EN}T_N$. The day and nighttime durations $\left(T_D \text{ and } T_N\right)$ are inputs to the energy balance model from the solar irradiance model and are updated for each day of the year. The solar array power output $\left(P_{SA}\right)$ is a data output from the solar array model. This leaves two variables $\left(P_{ED} \text{ and } P_{EN}\right)$ in a single equation. Both P_{ED} and P_{EN} are calculated in the electrical load model. Either can be substituted into the energy balance equation and the remaining variable is then determined. The computer program (PST MOD) uses the average night power for this substitution. The solved variable is no longer the actual average power but rather a power capability as shown below. The basic energy balance equation is now in the form :

$$P_{SA}\ T_D = \frac{P_{EN}\ T_N}{X_1} + \frac{P_D\ T_D}{X_2} \tag{63}$$

solving for the unknown day power capability, P_D,

$$P_D = \frac{X_2}{T_D}\left(P_{SA}\ T_D - \frac{P_{EN}\ T_N}{X_1}\right). \tag{64}$$

Day power capability is interpreted as the maximum average daytime power that can be supported by the PST with the provision that sufficient energy is stored to support the night load.

If $P_D = 0$, then the total solar array energy for a given day is just adequate to charge the battery and satisfy the night load requirement. If P_D is negative, the total solar array energy is insufficient to meet the night demand. In either of the above cases, power may be drawn from the PST system during the day or night; however, utility power will be used at some time during the day-night period. Specifically, suppose the energy from the array is,

$$P_{SA}\ T_D = 4\ \text{kWh}$$

and the nighttime energy requirement is,

$$\frac{P_{EN}\ T_N}{X_1} = 5\ \text{kWh}$$

This condition will produce a negative day power capability or,

$$P_D < 0$$

But, the four kWh could be entirely used during the daylight period leaving the battery in a discharged state (from the previous night load). The total nighttime energy plus any daytime energy not supplied by the PST would then be supplied by the utility.

The four kWh of solar array energy could also be used in any distribution between the day and night intervals depending on the load profile. Additional utility energy would still be required. If $P_D > 0$, the array provides ample energy for the night load. However, this condition alone will not guarantee sufficient PST energy to supply the total day-night demand. Once the day power capability has been determined, the energy balance comparison between the total load energy required and the PST energy available can be made. An average 24-hour PST bus capability is thus derived as follows,

$$P_{BUS} = \frac{P_D\ T_D + P_{EN}\ T_N}{T_D + T_N} \tag{65}$$

where, P_{BUS} = The 24-hour bus power capability that can be delivered by the PST on a given day (for a particular load profile).

From Equation 55 it is clear that the PST system can have output capability with a negative P_D.

Implicit in Equations 54 and 55 is the assumption that the battery is large enough to store the required nighttime energy. For this condition to hold, the battery must be able to deliver to the load at least the nighttime load energy requirement, $P_N\ T_N$. If this is not the case, Equation 54 and 55 must be modified to reflect the actual storage capacity. Battery storage capability is defined by an external input to the energy balance model. This input is divided into the ampere-hour capacity, C_R, and the average battery discharge voltage, V_D. The maximum average power that can be delivered by a fully charged battery is,

$$P_{NB} = \frac{C_R \; V_D}{T_N}$$

where, P_{NB} = Average battery output power capability

T_N = Night duration

C_R = Rated ampere-hour capacity

V_D = Average battery discharge voltage

(Note that $C_R V_D$ = battery energy capacity)

The actual average battery power capability at the load is considerably less than the battery output power capability due to system losses and the depth-of-discharge constraint. Battery load power capability is therefore,

$$P_{NBL} = \frac{\left(C_D/100\right) \; C_R \; V_D \; \eta_R \; \eta_{RL}}{T_N} \qquad (66)$$

where, C_R = Battery ampere-hour capacity

V_D = Average battery discharge voltage

η_R = Inverter efficiency

T_N = Night duration

η_{RL} = Line loss factor, inverter to load bus

C_D = Depth-of-discharge constraint in percent

The depth-of-discharge constraint is required to insure maximum battery life. The cycle life of lead acid batteries is significantly reduced if continually discharged to a zero state-of-charge (100% depth-of-discharge). For this reason, the level of energy depletion is limited to provide a satisfactory margin. For example, 70% depth-of-discharge is a commonly used value.

Once the battery output power at the load has been determined (eq. 56), a comparison is made between the actual average night load requirement P_{EN} and the average battery load power output capability, P_{NBL}.

If,

$$P_{NBL} \geq P_{EN}$$

the battery storage capacity is sufficient and the day power capability is defined by Equation 54.

If,

$$P_{NBL} < P_{EN}$$

the battery capacity is inadequate to support the entire nighttime energy requirement. Hence, from Equation 54 the day power capability must be modified to account for the restricted nighttime energy available or,

$$P_D = \frac{X_2}{T_D} \left(P_{SA} \; T_D - \frac{P_{NBL} \; T_N}{X_1} \right) \tag{67}$$

The average PST bus power capability is found by modifying Equation 55 to accommodate the correct day power capability and the battery output capability,

$$P_{BUS} = \frac{P_D \; T_D + P_{NBL} \; T_N}{T_D + T_N} \tag{68}$$

The total energy produced by the PST per 24 hour day is then,

$$E_{PST} = P_{BUS} \left(T_D + T_N \right) = 24.0 \; P_{BUS} \tag{69}$$

where E_{PST} = Total daily PST energy available.

The comparison between the energy required for the load and energy supplied by the PST is,

If $E_{PST} \geq E_L$, then $E_U = 0$

where E_L = the load energy required (output from the electrical load model)

E_U = utility energy required per day

If, $E_{PST} < E_L$, then

$E_U = E_L - E_{PST}$

As an index of power system operation a daily energy displacement factor

(E_d) is defined as

$$E_d = \frac{E_{PST}}{E_L} = \frac{\text{Total daily (24 hr) PST energy available}}{\text{Total daily (24 hr) energy used by load}}$$

If, $E_d \geq 1$, the PST power system is supporting 100% of the load demand for a given day. If, $E_d < 1$, the PST is only supplying a fraction of the load requirement and utility energy is required. For example, if $E_d = 0.35$, the PST is supporting 35% of the load demand and the utility sustains the remaining 65%.

The basic energy balance equation,

$$P_{SA}\, T_D = \frac{P_N\, T_N}{X_1} + \frac{P_D\, T_D}{X_2} \tag{70}$$

where, P_{SA} = Average daily solar array power output

T_D = Daylight duration

T_N = Night duration

P_N = Average night load power capability

P_D = Average day load power capability

X_1 = Lumped nighttime system efficiency

X_2 = Lumped daytime system efficiency

can be used effectively for the analysis of the demand-type power systems.

The factors that change in the general energy equation for the different EPS configurations are the night and day efficiencies X_1 and X_2. Figures A-7, A-8, and A-9 (see also fig. A-6) show the simplified EPS configuration block diagrams with related power flow diagrams.

From the power flow diagram for Configuration I (fig. A-7) the energy balance equation becomes,

$$P_{SA}\ T_D = \frac{P_N\ T_N}{\eta_D\ F_U\ \eta_{SL}\ \eta_{CD}\ \eta_B\ \eta_R\ \eta_{RL}} + \frac{P_D\ T_N}{\eta_D\ F_U\ \eta_{SL}\ \eta_{CD}\ \eta_R\ \eta_{RL}} \tag{71}$$

therefore,

$$X_1 = \eta_D\ F_U\ \eta_{SL}\ \eta_{CD}\ \eta_B\ \eta_R\ \eta_{RL}$$

$$X_2 = \eta_D\ F_U\ \eta_{SL}\ \eta_{CD}\ \eta_R\ \eta_R$$

. From the power flow diagram shown for configuration II (fig. A-8), the night and day efficiencies are:

$$X_1 = \eta_D\ F_U\ \eta_{SL}\ \eta_{CD}\ \eta_B\ \eta_{DB}\ \eta_R\ \eta_R$$

$$X_2 = \eta_D\ F_U\ \eta_{SL}\ \eta_R\ \eta_{RL}$$

The X_1 and X_2 values can be expressed for each configuration in the same manner. The X_1 and X_2 terms can be generalized for the four configurations by inserting all possible efficiency factors (from the four EPS configurations) into the following generalized efficiency terms:

$$X_1^{+} = \eta_D\ F_U\ \eta_{SL}\ \eta_{SR}\ \eta_{CD_1}\ \eta_B\ \eta_{DB}\ \eta_{BR}\ \eta_R\ \eta_{RL} \tag{72}$$

$$X_2 = \eta_D\ F_U\ \eta_{SL}\ \eta_{CD_2}\ \eta_{SR}\ \eta_R\ \eta_{RL} \tag{73}$$

for a configuration where a certain parameter may not apply, the value of that parameter becomes unity in the generalized efficiency terms. Table A-14 lists the parameters that are applicable to each configuration. Table A-15 defines all external input parameters for the energy balance model.

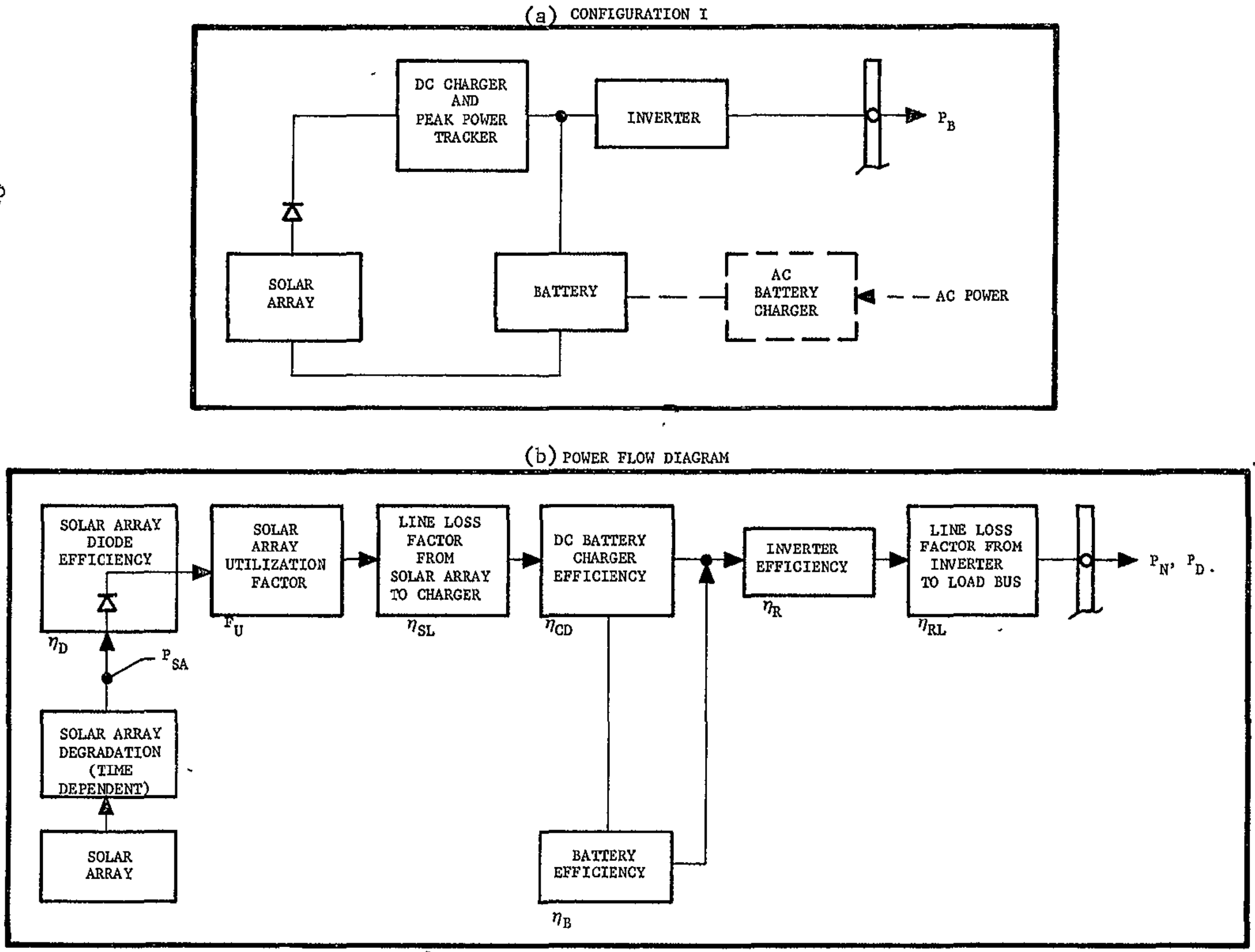

Figure A-7 Simplified Configuration I Block Diagram (a) and Power Flow Diagram (b)

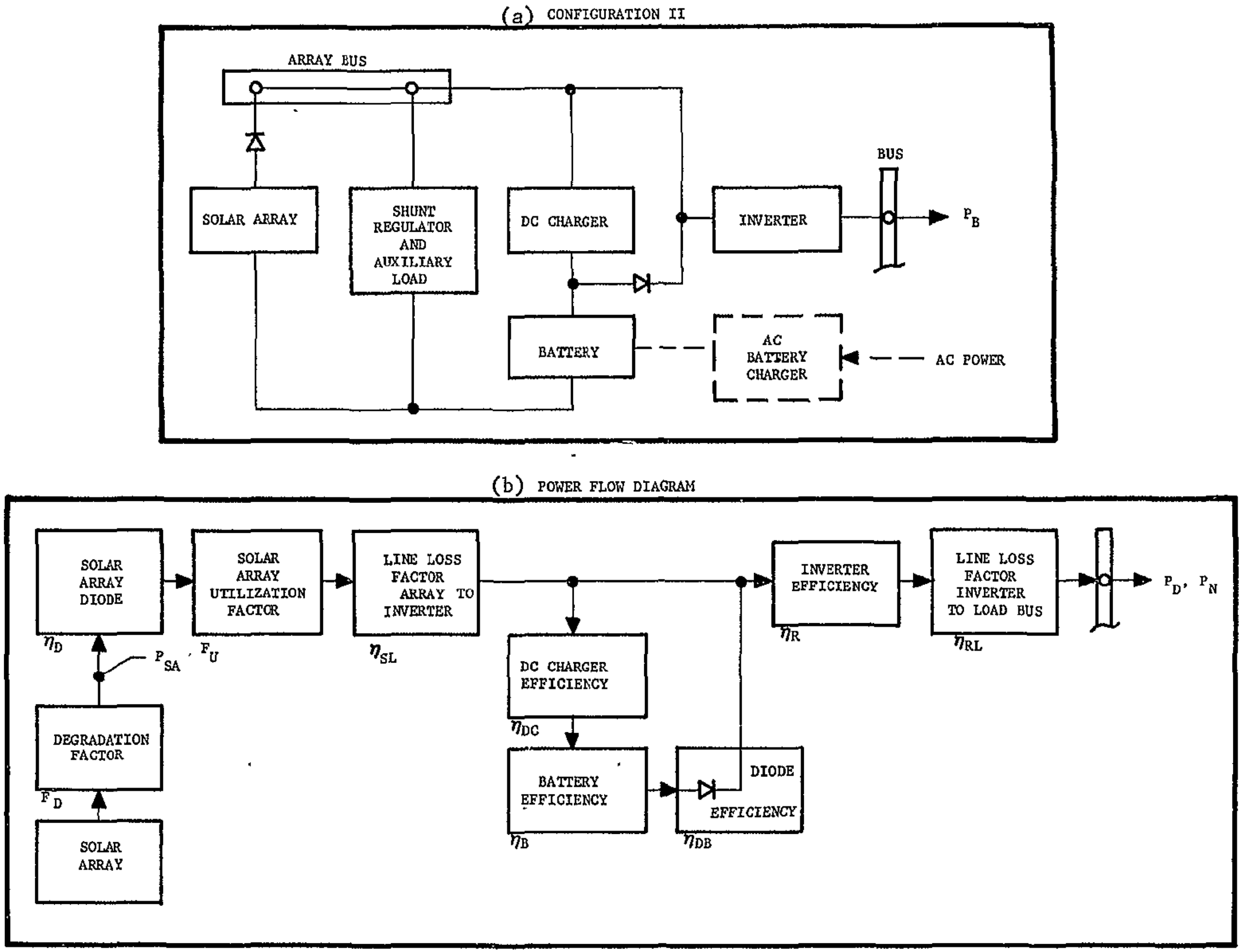

Figure A-8 Simplified Configuration II EPS Block Diagram (a) and Power Flow Diagram (b)

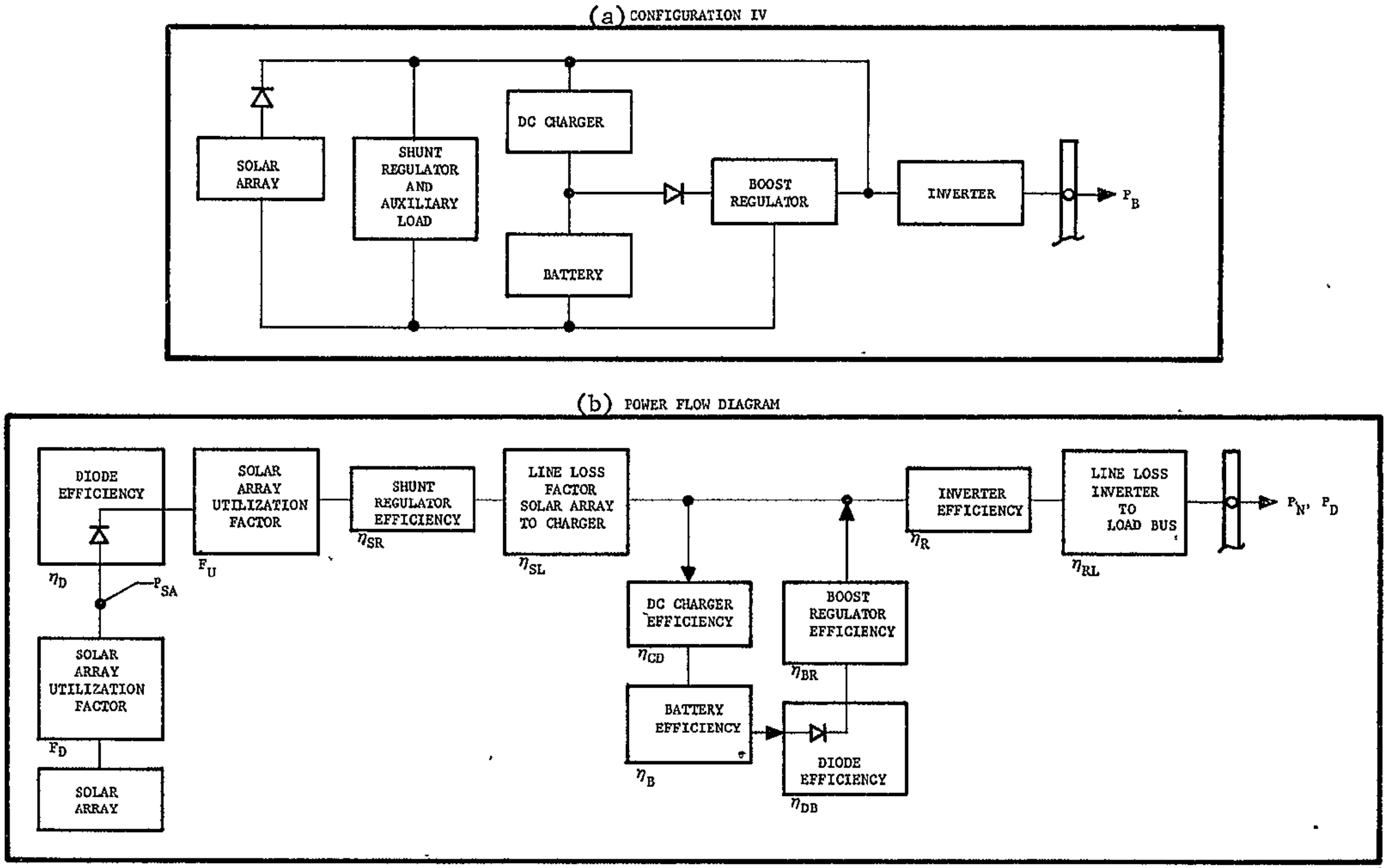

Figure A-9 Simplified Configuration IV EPS Block Diagram (a) and Power Flow Diagram (b)

Table A-14 Matrix for EPS Efficiency Parameters

Parameters	Configuration			
	I	II	III	IV
η_D, Diode Efficiency	x*	x	x	x
F_U, Solar Array Utilization Factor	x	x	x	x
η_{SL}, Line Factor	x	x	x	x
η_B, Battery Efficiency	x	x	x	x
η_R, Inverter Efficiency	x	x	x	x
η_{RL}, Line Loss Factor Inverter to Charger	x	x	x	x
η_{CD1}, dc Charger Efficiency (Night time)	x	x	1†	x
η_{CD2}, dc Charger Efficiency (Day time)	x	1	1	1
η_{SR}, Shunt Regulator Efficiency	1	1	x	x
η_{DB}, Diode Efficiency	1	x	1	x
η_{BR}, Boost Regulator Efficiency	1	1	1	x

*x - Denotes that the parameter is used in the given configuration and has a value that represents an efficiency loss.

†1 - Denotes that the parameter is not used and the value changes to unity.

Table A-15 Input Parameters for Energy Balance Model

Item	Parameter Description	Symbol
1	Solar Array Blocking Diode Efficiency	η_D
2	Battery Wh Efficiency	η_B
3	Inverter Efficiency	η_R
4	Line Loss Factor Inverter to Load Bus	η_{RL}
5	Line Loss Factor Array to Charger	η_{SL}
6	dc Charger Efficiency	η_{CD1} & η_{CD2}*
7	Solar Array Utilization Factor	F_U
8	Shunt Regulator Efficiency	η_{SR}
9	Battery Blocking Diode Efficiency	η_{DB}
10	Boost Regulator Efficiency	η_{BR}
11	Battery Depth of Discharge Constraint	C_D
12	Rated Battery Capacity, Ah	C_R
13	Average Battery Discharge Voltage	V_D

*Two charger efficiencies are defined to account for the charger efficiency in the night load η_{CD1} and the day load η_{CD2} where applicable.

5.2 Energy Balance Summary

The input parameters necessary for the energy balance model are shown in Table A-15. Other inputs to the EBM that are internal to the computer program are:

P_{SA}, from the solar array model;

T_N and T_D, from the solar irradiance model; and

P_L, P_{EN} and E_L from the electrical load model.

5.3 Calculations

Nighttime and daytime efficiency factors,

$$X_1 = \eta_D \, F_U \, \eta_{SL} \, \eta_{SR} \, \eta_{CD_1} \, \eta_B \, \eta_{DB} \, \eta_{BR} \, \eta_R \, \eta_{RL}$$

$$X_2 = \eta_D \, F_U \, \eta_{SL} \, \eta_{CD_2} \, \eta_{SR} \, \eta_R \, \eta_{RL}$$

Average battery load power capability,

$$P_{NBL} \doteq \frac{\left(C_D/100\right) C_R \, V_D \, \eta_R \, \eta_{RL}}{T_N} \tag{74}$$

(terms are defined in table A-15).

If the average battery load power capability exceeds the average load power required, the appropriate day power capability and average bus power capability are computed.

Is $P_{NBL} \geq P_{EN}$?

If yes, $$P_D = \frac{X_2}{T_D} \left(P_{SA} \, T_D - \frac{P_{EN} \, T_N}{X_1} \right) \tag{75}$$

$$P_{BUS} = \frac{P_D \, T_D + P_{EN} \, T_N}{T_D + T_N} \tag{76}$$

If no, $$P_D = \frac{X_2}{T_D}\left(P_{SA}\,T_D - \frac{P_{NBL}\,T_N}{X_1}\right) \tag{77}$$

$$P_{BUS} = \frac{P_D\,T_D + P_{NBL}\,T_N}{T_D + T_N}$$

Also, if $P_{BUS} \leq 0$

then $P_{BUS} = 0$ for both of the above conditions.

A system performance indicator (as a function of day duration) is included in the calculations as,

$$K = \frac{T_N/T_D}{X_1} + \frac{1}{X_2} \tag{78}$$

The factor K is independent of solar irradiance conditions. The reciprocal of K results in an average diurnal system efficiency, 1/K. This factor is indicative of the daily power system efficiency for a given time of year (function of daylight duration) and a specific site location. The actual daily power system efficiency is dependent on both the solar array output and the load or,

$$PST_{EFF} = \frac{\text{Total daily PST energy available}}{\text{Total daily solar array energy output}}$$

For convenience, daily average power margins for the PST system are calculated as,

$$P_{NM} = P_{NBL} - P_{EN} \tag{79}$$

where, P_{NM} = Average night power margin

P_{NBL} = Average battery power output capability

P_{EN} = Actual average night load requirement

$$P_{DM} = P_D - P_{ED} \tag{80}$$

where P_{DM} = Average day power margin

P_D = Average day power capability

P_{ED} = Actual average day load requirement

$$P_{BM} = P_{BUS} - P_L \tag{81}$$

where P_{BM} = Average bus power margin

P_{BUS} = Average bus power capability

P_L = Actual average power required by load

The total energy produced by the PST per 24 hour day $\left(E_{PST}\right)$ is calculated as,

$$E_{PST} = P_{BUS} \left(T_D + T_N\right) = 24.0\ P_{BUS} \tag{82}$$

The total daily energy from the PST is compared to the energy required by the load and the necessary utility energy, $\left(E_U\right)$ is calculated as follows,

If $E_{PST} \geq E_L$,

$E_U = 0$

If $E_{PST} < E_L$,

$E_U = E_L - E_{PST}$

The daily energy displacement is,

$$E_d = \frac{E_{PST}}{E_L} \tag{83}$$

For all proposed EPS configurations, the configuration without battery is simulated by setting, $P_{NBL} = 0$, and $T_N = 0$. In this mode of operation the day power capability and the average bus power capability are equal or,

$$P_D = P_{BUS}$$

Also, all excess energy is assumed as fed back or "stored" in the utility grid. If the stored energy can be sold back to the utility at the same cost as purchased utility energy, the utility grid acts as a 100% efficient energy storage system. This approach is necessary for an account of all PST energy and allows the comparison of energy systems to the theoretical maximum energy utilization. Detailed information on the selected power system design is given in Section 4.0, Conceptual Design of Residential PST.

6. REFERENCES

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APPENDIX B

DERIVATION OF POWER-TEMPERATURE COEFFICIENT

The maximum power density, P_{MP} for the typical solar cell is

$$P_{MP_{28}} = 11.3 \text{ mW/cm}^2 \text{ at temperature of } 28^\circ\text{C}$$

$$\text{insolation of } 100 \text{ mW/cm}^2$$

The power density coefficient (γ_ρ) on the cell level is,

$$\gamma_\rho = -0.039 \text{ mW/cm}^2 \text{ per } ^\circ\text{C}.$$

Therefore, the cell power density at any given temperature, t, is,

$$P_{MP_t} = P_{MP_{28}} + (t - 28^\circ\text{C})\ \gamma_\rho$$

Thus, at 60°C (minimum output for the subarray was specified at 60°C and 100 mW/cm^2 by NASA-LeRC).

$$P_{MP_{60}} = 11.3 \text{ mW/cm}^2 + (60^\circ\text{C} - 28^\circ\text{C})(-0.039 \text{ mW/cm}^2 - {}^\circ\text{C})$$

$$= 10.052 \text{ mW/cm}^2$$

The total subarray area,

$$A_{SUB} = 1.486 \text{ m}^2 \ (16 \text{ ft}^2).$$

If the entire subarray area could be used as solar cell surface area, the subarray output power, P_{SAM_I} (at 60°C and 100 mW/cm^2) would be:

$$P_{SAM_I} = A_{SUB}\ P_{MP_{60}} = 1.486 \times 10^4 \text{ cm}^2 \times 10.052 \text{ mW/cm}^2$$

$$= 14.93 \times 10^4 \text{ mW} = 149.3 \text{ watts}$$

For a specified subarray power output the solar cell packing factor (PF) is

$$PF = \frac{P_{SAM60}}{P_{SAM_I}}$$

where P_{SAM60} is a specified subarray power output at 60°C and insolation level of 100 mW/cm^2.

For a P_{SAM60} = 85W (specified value).

$$PF_{85} = \frac{85}{149.3} = 0.569$$

The subarray power output at 28°C is,

$$P_{SAM28} = \left(A_{SUB}\right)\left(P_{MP_{28}}\right) PF$$

$$= (1.486 \times 10^4 \text{ cm}^2)(11.3 \text{ mW/cm}^2)(0.569)(10^{-3} \text{ W/mW})$$

$$= 95.54 \text{ watts}$$

The power-temperature coefficient (γ) can now be determined as,

$$\gamma = \frac{P_{SAM60} - P_{SAM28}}{60°C - 28°C}$$

For the case of P_{SAM60} = 85W,

$$\gamma_{85} = \frac{85 - 95.54}{32} = -0.329 \text{ W/°C}$$

A general expression for γ is,

$$\gamma = \frac{P_{SAM60} - A_{SUB} \; P_{MP_{28}} \; (PF)}{60°C - 28°C}$$

Note that the packing factor, PF, is a function of the given P_{SAM60}. Therefore, for a P_{SAM60} = 70W,

$$PF_{70} = \frac{70}{149.3} = 0.468, \text{ and}$$

$$\gamma_{70} = \frac{70 - (1.486 \times 10^4)(11.3)(0.468)(10^{-3})}{32} = -0.268 \text{ w/°C}$$

Likewise, for P_{SAM60} = 100W

$$\gamma_{100} = -0.389 \text{ W/°C}$$

APPENDIX C

TEST PLAN

1.0 INTRODUCTION

1.1 Purpose

The purpose of this test plan is to define the test program for the evaluation of the Photovoltaic Residential Prototype System.

1.2 Scope

This document defines the plan to be used for implementing the power system test requirements. The plan defines the tests to be conducted including the test objectives(s), test method, and data required for each test. This plan also defines the test conditions, documentation requirements, program schedule, servicing and maintenance, and special considerations affecting cost and schedule.

1.3 System Configuration

This test plan defines the tests for the three system configurations.

Configuration IIIA- EPS without battery - This system, shown in the simplified block diagram in Figure C-1, uses all of the solar array power to supply the inverter output requirements. The ac power output from the inverter is used to offset the energy required from the utility (i.e., power fed back to utility).

An inverter control unit provides synchronization with the utility and controls the inverter output to maintain the solar array at the peak power point. No battery is used and the shunt regulator will be required only if the solar array power output exceeds the inverter capability.

Configuration IIIB - EPS with Small Battery and without utility - This system (see Figure C-2) uses the solar array power for the daytime loads and for battery charging when energy is available. The battery provides the energy required for transient loads and supplements the energy required for short periods of low insolation. The small battery may be simulated using the battery of Configuration IIIC and limiting the depth-of-discharge through

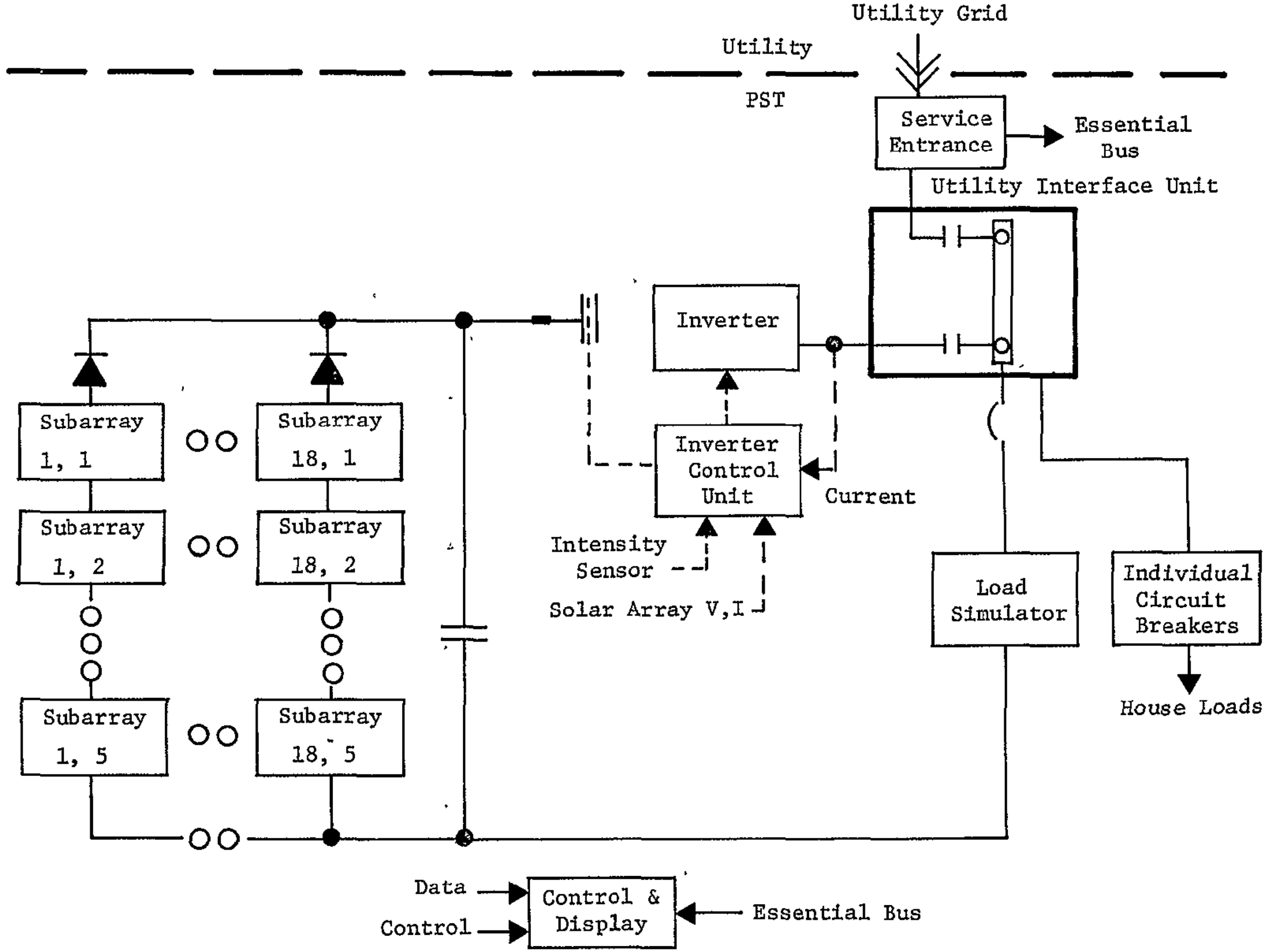

Figure C-1 Functional Block Diagram of EPS Employing Power Feedback to Utility (No Battery)

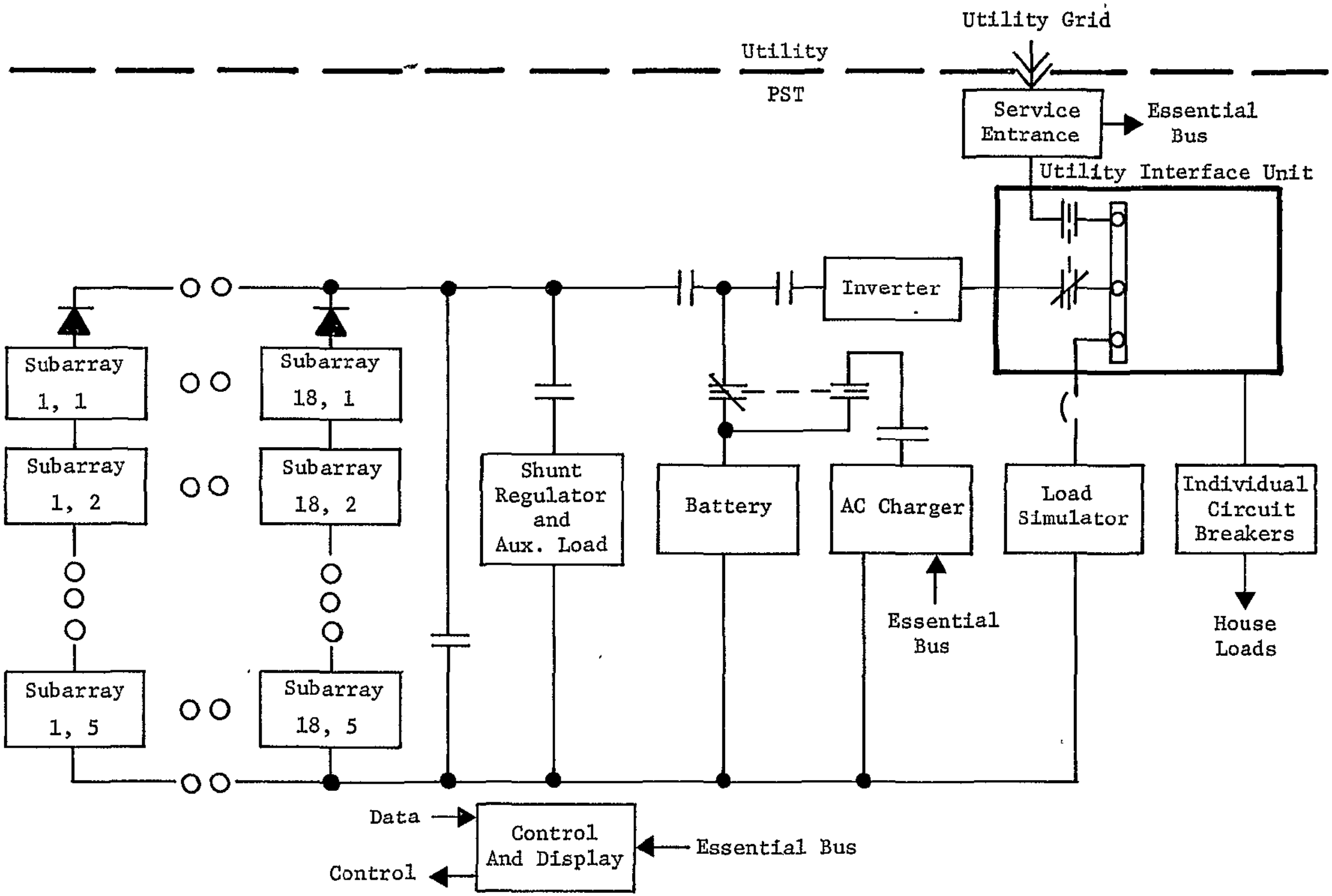

Figure C-2 Functional Block Diagram of EPS with Battery (No Power Feedback to Utility) software. Nighttime power is provided from the utility. For improved efficiency at light loads, the system uses a second small inverter.

Configuration IIIC - EPS with large battery and without utility.-This system configuration is similar to Configuration IIIB (see Figure C-2) except the battery is a large unit capable of storing the energy required for nighttime operation. Utility power is used only when peak inverter capability or PST power capability is exceeded.

1.4 Ground Rules and Assumptions

The test plan was prepared based on the following criteria:

(1) All tests will be conducted at the Regional PST although some of the tests may be performed at the LeRC house to provide preliminary data on equipment performance. These data may then be used to update parameters in the computer model.

(2) All hardware has been tested before delivery and requires only minimum testing to verify that the unit is functional. Additional testing is performed on the solar array and battery after assembly of the modules.

(3) The battery cells are assumed to have been activated either at the manufacturer's plant or at the test site before the subassembly tests.

(4) Tests are defined to make maximum use of equipment which is required in the system tests and to eliminate the need for special purpose test equipment where possible.

(5) The software checkout for both the data acquisition and control unit, and the central computer (data reduction) is assumed to have been completed.

2. APPLICABLE DOCUMENTS

None.

3. REQUIREMENTS

3.1 Test Program

The test program consists of two basic test classes. The first class is nonrecurring (unless equipment replacement occurs) and consists of preinstallation tests for modular equipment and the initial system checkout. The second class or recurring tests includes all system and component evaluation tests.

3.1.1 Subassembly Tests

These tests shall be performed on the solar array and battery subassemblies before initial installation and on replacement units.

3.1.1.1 Solar Array Subassemblies (Subarray or Module)

a. Test Objective - Obtain data to verify the performance of the solar array subassembly before installation.

b. Test Method - Obtain I-V curve for each subarray with sun normal to array face.

c. Measurements - Subarray voltage, current, temperature and total intensity shall be recorded.

d. Data Reduction and Analysis - Extrapolate I-V data to I-V curve at AM1 and 28 °C for comparison with standardized curve.

3.1.1.2 Battery Cells

a. Test Objective - Verify that the cell meets the specified performance before installation.

b. Test Method - After cell activation, perform two charge/discharge cycles with no stand time between charge and discharge. Follow with a third cycle having a 48-hour stand between charge and discharge.

c. Measurements - Cell voltage, current, and temperature shall be recorded. The electrolyte specific gravity shall be measured and recorded before cycle three and during the 48-hour stand.

d. Data Reduction and Analysis - Calculate W-h in, W-h out, A-h in and A-h out for cycles 2 and 3. Determine the W-h and A-h cycle efficiency. These shall be equal for cycles 2 and 3 within the tolerance to be determined during PST testing.

3.1.2 Startup Tests

These tests shall be performed to verify the performance of each component under controlled electrical conditions (fixed load, limited input current, etc) and their interfaces.

3.1.2.1 Data Acquisition and Control

a. Test Objective - Determine that the Data Acquisition and Control Subsystem is responding to stimuli and issuing commands under the control of the microprocessor.

b. Test Method - The system hardware and software shall be checked using stimuli, as necessary, to verify that all data channels are functional. Using stimuli or manual entries to the processor, all command channels shall be verified.

c. Measurements - Recording of data from sensors and the response of equipment to the commands shall be verified.

3.1.2.2 ac Charger

a. Test Objective - Verify the proper operation of the ac charger.

b. Test Method - The performance of the ac charger shall be verified by determining voltage and current limiting using the resistive section of the load simulator.

c. Measurements - Record voltage and current at the ac charger output for no load to 150% of full load.

d. Data Reduction and Analysis - A plot of current versus voltage shall be prepared.

3.1.2.3 Inverter/ac Charger

a. Test Objective - Verify proper operation of the inverter(s) before operation with the battery and solar array.

b. Test Method - The performance of each inverter shall be verified by loading the inverter with step loads at the range of power factors (0.95 leading to 0.7 lagging) to the maximum load compatible with the current limited ac charger.

c. Measurements - Inverter input and output voltages, output powers, and temperature shall be recorded for each load.

d. Data Reduction and Analysis - Calculate VA, VAR, and efficiency at each load.

3.1.2.4 Battery/ac Charger

a. Test Objective - Determine battery performance at various discharge rates.

b. Test Method - The battery will be charged at a constant C/10 rate using the ac charger followed by discharge at rates of C/20, C/10, and C/5 to compare actual and predicted capacity performance.

c. Measurements - Record battery voltage and current, battery module voltages, and battery module temperatures periodically during charge and discharges. Monitor and record individual cell voltages manually to determine and replace severely mismatched cells.

e. Data Reduction and Analysis - Calculate W-h in, W-h out, A-h in and A-h out. Plot charge and discharge voltage and current.

3.1.2.5 Battery/Inverter

a. Test Objective - Verify proper operation with the battery from no load to full load.

b. Test Method - The performance of the inverter shall be verified by loading the inverter with programmed loads representing the range of power factors from no load to full load on the inverter with phase unbalance.

c. Measurements - Inverter input and output voltages, output power, and temperature shall be recorded for each load.

d. Data Reduction and Analysis - Calculate VA, VAR, and efficiency at each load.

3.1.2.6 Solar Array/Shunt Regulator

a. Test Objective - Verify capability of shunt regulator to regulate solar array output.

b. Test Method - With the unshorted solar array bus connected to the shunt regulator, monitor the shunt regulator performance over one daylight cycle.

c. Measurements - Record solar array output voltage and current, temperatures, subarray voltage and current and all intensity sensors and meteorological data.

3.1.2.7 Utility Interface

a. Test Objectives - Verify that the interlocks preventing simultaneous operation of the inverter and utility are functioning.

b. Test Method - With inverter and utility power available and the switch interlocks enabled, issue commands for transfer of power. Test all switches.

c. Measurements - Monitor switch status and record switch status and the inverter, utility, and load current.

3.1.3 Component Tests

The following tests are performed, as required, to meet the objectives of the system configuration tests.

3.1.3.1 Solar Array

a. Test Objectives - The test objectives for the solar array are:

1. Determine the effects of environmental conditions on performance (such as rain, snow, hail, humidity, dust, wind direction and velocity, ambient pressure and temperature).

2. Determine output characteristics versus insolation conditions for total intensity on array surface, sky radiation level, and time of year.

3. Determine the temperature gradient across the array and its effect on performance.

4. Determine key factors affecting temperatures.

5. Evaluate factors that degrade performance.

6. Determine the relationship between the outputs of the calibrated solar cell and the pyranometer under various solar irradiance and atmospheric conditions.

7. Evaluate methods of calibrating the array output (analytical and test) and recommend approach.

8. Evaluate methods of determining array peak power output capability.

b. Test Method - Obtain data to define the meteorological conditions, insolation, SA average temperature, and SA electrical output. Determine the sun elevation and azimuth. Determine solar energy use, SA degradation, and efficiency.

c. Measurements, Data Reduction and Analysis - Solar array data requirements are defined in Table C-1. Parameter calculations required are defined in Table C-2.

3.1.3.2 Battery (Configuration IIIB and IIIC)

a. Test Objectives - The test objectives for the battery are:

1. Determine battery voltage, current, and temperature characteristics during charge and discharge under the PST operating conditions.

2. Determine battery capacity degradation as a function of PST operating conditions.

3. Determine extent of battery cell state-of-charge and voltage imbalance.

4. Determine battery temperature gradient.

5. Determine battery W-h and A-h efficiencies.

b. Test Method - Obtain data to define the battery performance, efficiency, and temperature gradients during each system test using the battery. Determine the battery cell capacity and cell voltage mismatch.

c. Measurements, Data Reduction and Analysis - Battery data requirements are defined in Table C-1. Calculated parameter requirements are defined in Table C-2.

3.1.3.3 Inverter

a. Test Objectives

1. Determine inverter output power characteristics and efficiency as a function of input voltage and of load power and power factor.

2. Evaluate the performance of the inverter when synchronized and paralleled with the utility grid.

Table C-1 Component Test Measurement Requirements

	Component/Subsystem				
	Solar Array	Battery	Inverter	Shunt Regulator	Distri-bution
Local Time	x	x	x	x	x
Utility Voltage					x
Utility Current					x
Utility Power					x
Load Voltage					x
Load Current					x
Load Power					x
Switch Status		x	x	x	x
Inverter ac Voltage			x		x
Inverter ac Current			x		x
Inverter ac Power			x		x
Inverter dc Voltage			x		x
Inverter dc Current			x		x
Inverter Temperature			x		
Reverse Output Current			x		
Phase Displacement and Synchro-nization			x		
Solar Array Voltage	x				x
Solar Array Current	x				x
Solar Array Temperature	x		x		
Subarray Voltage	x				
Subarray Current	x				
Wind Velocity	x				
Wind Direction	x				
Temperature	x				
Barometric Pressure	x				
Humidity	x				
Total Intensity	x				
Array Degradation Sensor	x				
Hemispherical Solar Irradiance					
- Horizontal	x				
- Array Angle	x				
Normal Solar Irradiance	x				
Solar Intensity	x				
Battery Voltage		x			
Battery Module Voltage		x			
Battery Current		x			
Battery Temperature		x			
Battery Electrolyte Specific Gravity		x			
Shunt Regulator Voltage				x	x
Shunt Regulator Current				x	x
Shunt Regulator Temperature				x	
Shunt Regulator Air Flow				x	

Table C-2 Component Test Computed Parameters

Measurement	Component/Subsystem				
	Solar Array	Battery	Inverter	Shunt Regulator	Distribution
Total Utility Energy					x
Utility VAR					x
Load VAR					x
Inverter dc Energy			x		
Inverter ac Energy			x		x
Load Energy					x
Inverter VAR			x		x
Inverter Power In			x		
Inverter Efficiency			x		
Solar Array Power Used	x				
Solar Array Peak Power	x				
Solar Array Average Temperature	x				
Solar Array Energy Used	x				
Solar Array Energy Available	x				
Solar Array Power Degradation	x				
Clearness Number	x				
Sky Diffused Irradiance Factor	x				
Percent Sunshine	x				
Battery Cell Voltage Average		x			
Battery A-h Capacity		x			
Battery Energy		x			
Shunt Regulator Power				x	

b. Test Method - Obtain inverter performance data during each system test. Determine inverter efficiency for the range of input voltages and loads. Determine performance differences when paralleled with the utility and when free running.

c. Measurements, Data Reduction and Analysis - Inverter data requirements are defined in Table C-1. Required calculated parameters are defined in Table C-2.

3.1.3.4 Shunt Regulator

a. Test Objectives

1. Determine the shunt regulator voltage regulation characteristics as a function of solar array output and load.

2. Determine the percent of power supplied to the shunt regulator that is delivered to the auxiliary load.

b. Test Method - Shunt regulator and auxiliary load data shall be obtained during each system test of Configurations IIIB and IIIC. Power supplied by the shunt regulator to auxiliary loads and supplemental ac power shall be determined.

c. Measurements, Data Reduction and Analysis - Shunt regulator data requirements are defined in Table C-1. Calculated parameter requirements are defined in Table C-2.

3.1.3.5 Power Distribution Subsystem

a. Test Objectives

1. Determine the power loss in distribution wiring under various load conditions.

2. Verify capability to switch the dc and ac loads under all load conditions.

a. Test Method - Obtain data to define distribution losses in both the ac and dc distribution. Semiannually determine the time required to open/close power switches and the noise created.

c. Measurements, Data Reduction and Analysis - Data requirements for distribution loss definition are shown in Table C-1. Calculated parameter requirements are defined in Table C-2. For switch performance tests, an oscilloscope and camera are required.

3.1.4 System Configuration Tests

The system configuration tests use the component test data (for participating components) acquired during the test to determine system performance. Tests are performed periodically throughout the test program.

a. System Test Objectives - System level test objectives for PST are:

1. Verify system operation under several projected 24-hour load profiles with environmental and seasonal variations.

2. Determine the overall practicality of the photovoltaic system concept.

3. Determine maintenance requirements for PST equipment.

4. Determine safety requirements for the PST.

5. Identify key technology areas for future optimization of system design and performance.

6. Identify projected cost (nonrecurring and recurring) and down time impact.

7. Identify technical and economical considerations affecting requirements for subsequent "hands-off" operation in Residential Model System.

8. Determine the key parameters required for the simplified computer program.

3.1.4.1 PST and Utility without battery (Configuration IIIA)

a. Test Objectives

1. Determine the ability of the inverter control unit to operate the solar array at the peak power point.

2. Determine the overall power and energy efficiency of the PST power system.

b. Test Method - Operate the PST power system (without the battery) in parallel with the utility. Determine the system performance by applying programmed loads, from no load to 125% of the inverter rating, at five times during the day (early morning, midmorning, near solar noon, midafternoon, and late afternoon).

c. Measurements - Data shall be recorded from before sunrise until after sunset for the solar array, inverter, inverter control unit, and the distribution system.

d. Data Reduction and Analysis - Plots shall be prepared to show, with respect to time, the solar intensity, solar array peak power capability, solar array power out, inverter power and VAR out, utility power and VAR, and load power and VAR. Inverter efficiency shall be calculated at each load during the programmed loading. Load energy, inverter energy, and utility energy shall be computed.

3.1.4.2 PST and Small Battery without Utility - (Configuration IIIB)

a. Test Objectives

1. Evaluate the practicality of the switching operation (battery at full charge, utility for long peak loads and day/night, inverter transfer).

2. Determine the overall power and energy efficiency of the PST power system for the day only operation with a small battery.

3. Determine the performance of the shunt regulator/auxiliary load in maintaining the solar array near the maximum power point.

b. Test Method - Operate the PST power system with software limiting the battery depth-of-discharge. The system performance shall be determined by applying programmed loads from no load to 125% of the largest inverter rating. This will be performed five times during the day.

c. Measurements - Data shall be recorded from before sunrise until after sunset for the solar array, inverter, shunt regulator, battery and the power distribution system.

d. Data Reduction and Analysis - Compute the load energy, inverter energy out, and utility energy. Determine the efficiency of the operating inverter during the programmed load period. Calculate the battery W-h and A-h efficiency and the shunt regulator and auxiliary load power and energy. Plot (with respect to time) the solar intensity, solar array peak power capability, solar array power out, inverter(s) power and VAR out, utility power and VAR, load power and VAR, battery voltage and current and shunt regulator voltage and current.

3.1.4.3 PST and Battery without Utility - (Configuration IIIB)

a. Test Objectives

1. Evaluate the practicality of the switching operation (battery at full charge, utility for loads exceeding inverter capability or at energy depletion and inverter transfer).

2. Determine the overall power and energy efficiencies of the PST power system in continuous day/night operation.

3. Determine the performance of the shunt regulator/auxiliary load in maintaining the solar array near the peak power point.

b. Test Method - The PST power system shall be operated in the full battery configuration. The system performance shall be determined by applying programmed loads to create a power profile representative of the typical home for the day, season, and weather. The test shall be run continuously for 10 days. The test shall start before noon. The battery state-of-charge shall be at least 70%.

c. Measurements - Data shall be recorded for the solar array, battery, shunt regulator, inverter, and power distribution system.

d. Data Reduction and Analysis - Compute all parameters for the battery, inverter(s), shunt regulator, and distribution system. Plot (with respect to time) the solar intensity, solar array peak power capability, solar array power out, inverter(s) power and VAR out, load power and VAR, battery voltage and current, shunt regulator voltage and current, and, if transfer to the utility occurred, the utility power and VAR.

3.2 Test Procedures

Each test defined in 3.1 shall be conducted according to an approved detailed test procedure. A test procedure may cover one or more of the defined tests. Each test procedure shall define the test in sufficient detail to assure that the requirements of this plan are implemented and data acquired will be adequate to accomplish the test objectives. The procedure shall include, but not be limited to, the detailed method for the following items:

a. Test method and order of events.

b. Instrumentation - Measurements to be recorded, method of acquisition and reduction, and format of presentation for all data.

c. Method and formula for extrapolating or converting data to desired results.

d. Method of controlling fixed parameters.

e. Limiting environmental criteria for conducting tests other than specified in the test plan.

3.3 Software

3.3.1 Control

The following software is required for the control of the PST and for display of selected parameters:

a. Control Algorithm - This algorithm must provide the capability to select the system configuration, monitor safety parameters, record required data channels at the defined time interval, and issue commands to system switches.

b. Load Simulator Algorithm - This algorithm computes the required resistive and reactive impedance for a requested Z and power factor and determines the load simulator switch settings required.

c. Data Display Algorithm - This algorithm formats and controls displayed data on DVMs, teletype, or CRT.

3.3.2 Data Analysis

The data from tests performed in 3.1 shall be used to determine the operating characteristics of the PST power system and its components. The analysis shall determine, but not be limited to, the following characteristics:

a. System

1. Overall system energy efficiency on a daily basis.

2. Operating characteristics, including efficiency as a function of load.

3. Daily energy available for auxiliary dc loads.

b. Solar Array

1. Solar array output as a function of insolation, weather conditions, and season.

2. Temperature gradients between subarrays and effect on overall solar array performance.

c. Battery

1. Battery duty cycle required on a daily basis (number of cycles and depth-of-discharge).

2. Battery degradation as a function of time.

3. Operating characteristics, including efficiency, as a function of charge/discharge voltage, current, and temperature.

4. Battery W-h and A-h efficiency.

d. Inverter

1. Operating efficiency as a function of load, input voltage, and tie to the utility grid.

2. Inverter output power characteristics as a function of load input voltage.

e. Shunt Regulator

1. Voltage regulation as a function of solar array output and load.

2. Shunt regulator efficiency in distributing power to auxiliary loads as a function of input power.

f. Power Distribution - Energy loss in wiring as a function of load.

3.4 Reports

Summary test reports shall be prepared quarterly. A formal test report shall be prepared annually.

3.5 Schedule

The schedule for PST tests is shown in Figure C-3 except for the subassembly tests. The subassembly tests should be performed as soon as possible after delivery to the test site. Tests marked with an asterisk (*) may be performed at another site (e.g., LeRC) to obtain early data with most, if not all, of the test objectives satisfied.

3.6 Servicing and Maintenance

The equipment is intended to operate with no maintenance except for the following:

a. Solar Array - The array surface and reference solar cells shall be cleaned periodically as determined during the PST test program.

b. Intensity Sensors - These sensors shall be cleaned each morning of testing.

c. Atmospheric Measurement Instruments - These instruments shall be cleaned as required.

d. Battery

1. The battery electrolyte level shall be checked regularly (as determined during the PST test program) and water added as required to maintain the required level.

2. The cell terminals shall be periodically inspected and maintained free of corrosion.

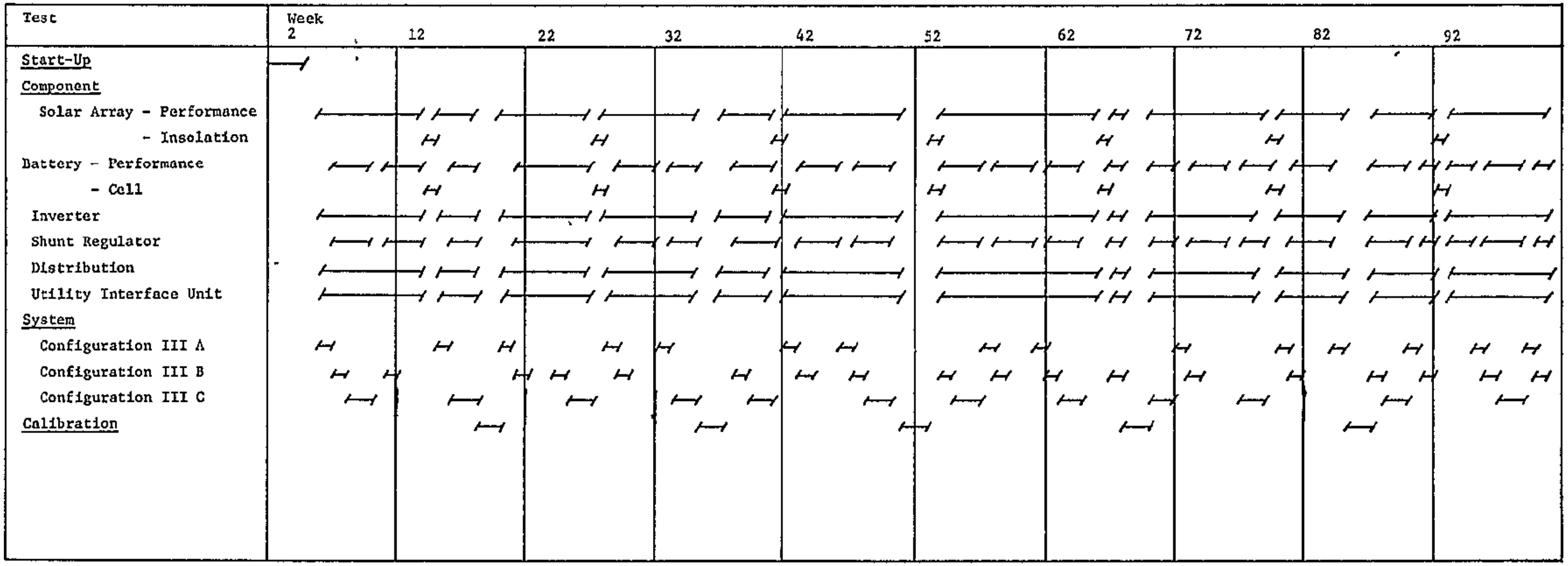

Figure C-3 Suggested Test Schedule

3. The specific gravity of the electrolyte of each cell shall be checked periodically and cells failing to meet the manufacturer's recommendations replaced.

e. Distribution Switches - The electromechanical switch contacts shall be inspected periodically for erosion and replaced as required.

f. Control and Display - Chart replacement as required and other maintenance and servicing in accordance with equipment manuals.

3.7 Safety

The design of the PST equipment and ancillaries provides for the safe system shutdown in the event of overloads, low battery voltage, shunt regulator failures, etc. Personnel hazards outside the equipment areas are similar to those encountered in a home or office. During periods of equipment maintenance, personnel may be exposed to the following hazards necessitating the use of the protective equipment or devices defined.

a. Solar Array - Daylight maintenance will require the closing of the solar array shorting switch to protect against the high dc voltage. Additional grounds will be required in the work area.

b. Battery - To protect against the electrolyte, the high dc voltage and the possibility of H_2 gas, protective rubber shoes and gloves, and a face mask must be worn while in the battery enclosure. Smoking is prohibited and tools must not be placed on the battery cells.

c. Shunt Regulator - Hot surfaces will exist for a period after disconnect of the shunt regulator. Dissipative elements must be allowed to cool before starting maintenance.

d. Power Distribution - High voltage ac and dc are present in the distribution system. When possible all power should be removed from the area of work and the buses grounded. Otherwise, protective gloves must be used.

4. MANAGEMENT

4.1 Management Control

a. To ensure that program schedules are met, a status reporting system shall be developed. The reporting shall include weekly internal status reports, a monthly status letter, quarterly summary test reports, and an annual formal test report. The test schedule has time allowed for equipment calibration at four month intervals. Data processing schedules and data review will be scheduled after the site location and data processing facilities are defined.

b. The simplified computer program will be used to provide estimates of system performance before running a test.

4.2 Estimated Operating Cost

The chart (see Table C-3) defines the estimated manpower requirements by skill and the estimated data reduction time. The data reduction time estimate is based on central processor time for a system such as CDC 6000 or IBM 370.

4.3 Procurement Lead Time

Table C-4 shows the PST component development status and estimated delivery time.

Table C-3 Estimated Operating Manpower and Computer Time Requirements

Cost Item	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
Labor (Hours)																								
Engineer	3.0	3.0	3.0	3.0	2.0	2.0	2.0	2.0	1.5	1.5	1.5	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Technician -Electrical	3.0	3.0	3.0	3.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	1.0	1.5	1.0	1.0	1.5	1.0	1.0	1.5	1.0	1.0	1.5
Technician -Mechanical	1.0	1.0		1.0		1.0		1.0		1.0		1.0		1.0			1.0			1.0			1.0	
Computer CP Hours	0.2	0.5	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Table C-4 Equipment Development Status

Component	Development Status	Delivery, Months
Inverter	Off the Shelf	3 to 6
Battery	Off the Shelf	6 to 9
Shunt Regulator*	New Development	6 to 9
Inverter Control Unit	New Development	9 to 12
Utility Interface Unit	Modified Off the Shelf	3 to 6
Data Acquisition & Control Unit	Modified Off the Shelf	12 to 15

*Engineering hours to design, develop, and fabricate shunt regulator ~ 750 hours. Hardware cost ~ $1100.

APPENDIX D

TEST PROCEDURE

1. INTRODUCTION

1.1 Purpose

The purpose of this document is to define the procedures required to perform the tests for the PST power system.

1.2 Scope

This document defines the procedure to be used for testing the PST power system. The procedure defines the operation and testing associated with the PST including the instrumentation and data acquisition, reduction and storage devices.

1.3 System Configuration

This test procedure defines the testing for the three system configurations.

Configuration IIIA (PST and Utility without Battery. This system, shown in the simplified block diagram in Figure D-1 uses all of the solar array power to supply the inverter output requirements. The ac power output from the inverter is used to offset the energy required from the utility. An inverter control unit provides synchronization with the utility and controls the inverter output to maintain the solar array at the peak power point. No battery is used and the shunt regulator will be required only if the solar array power output exceeds the inverter capability.

Configuration IIIB (PST and Small Battery without Utility). This system (see Figure D-2) uses the solar array power for the daytime loads and for battery charging when energy is available. The battery provides the energy required for transient loads and supplements the energy required for short periods of low insolation. The small battery is simulated by using the battery of Configuration IIIC and software to limit the depth-of-discharge. Nighttime power is provided from the utility. For improved efficiency at light loads, the system uses a second small inverter.

Configuration IIIC (PST and Battery without Utility). This system configuration is similar to Configuration IIIB (see Figure D-2) except the battery is a large unit capable of storing the energy required for nightime operation. Utility power is used only when the peak inverter capability or PST power capability is exceeded.

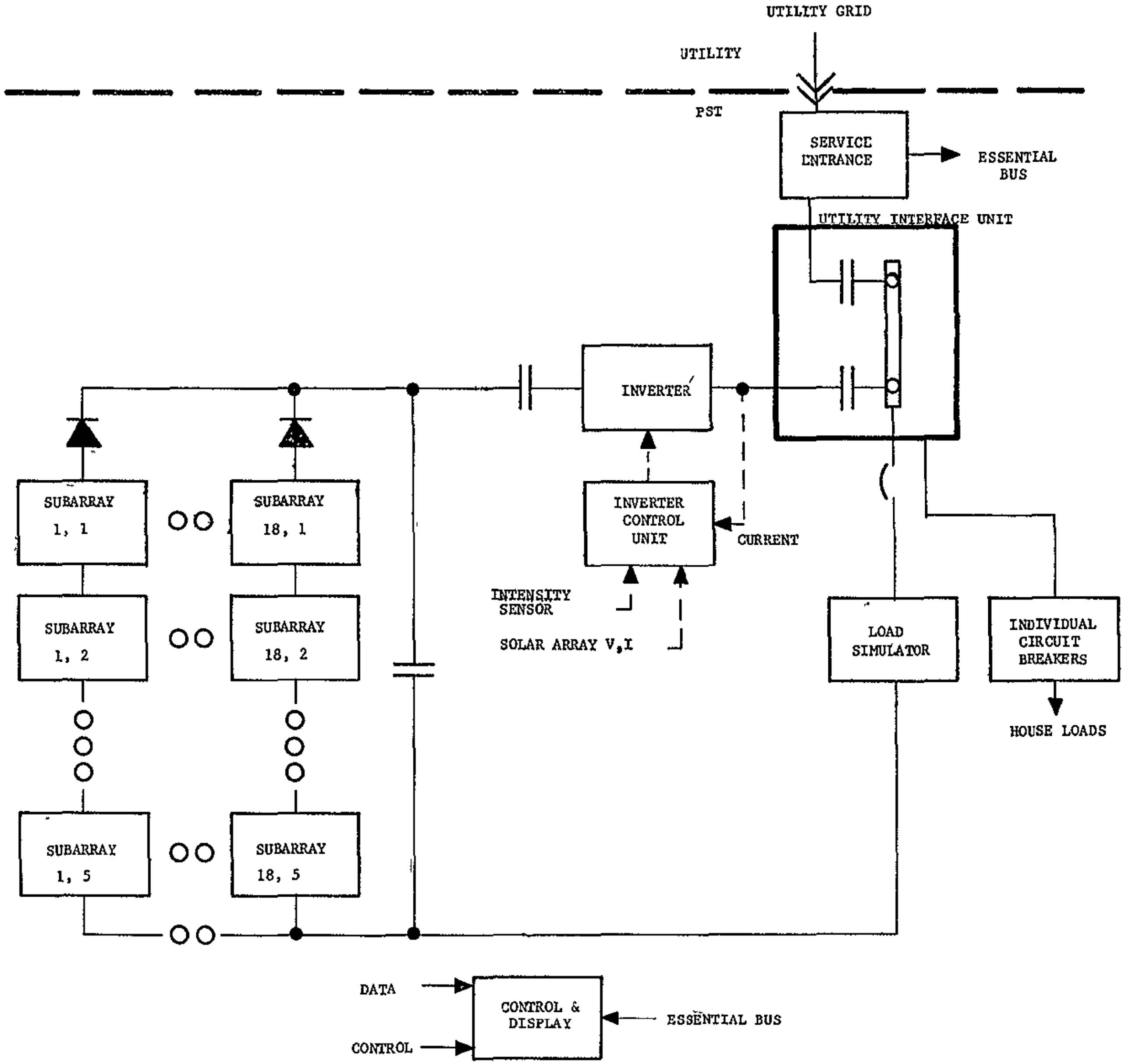

Figure D-1 Functional Block Diagram of EPS System Employing Power Feed Back

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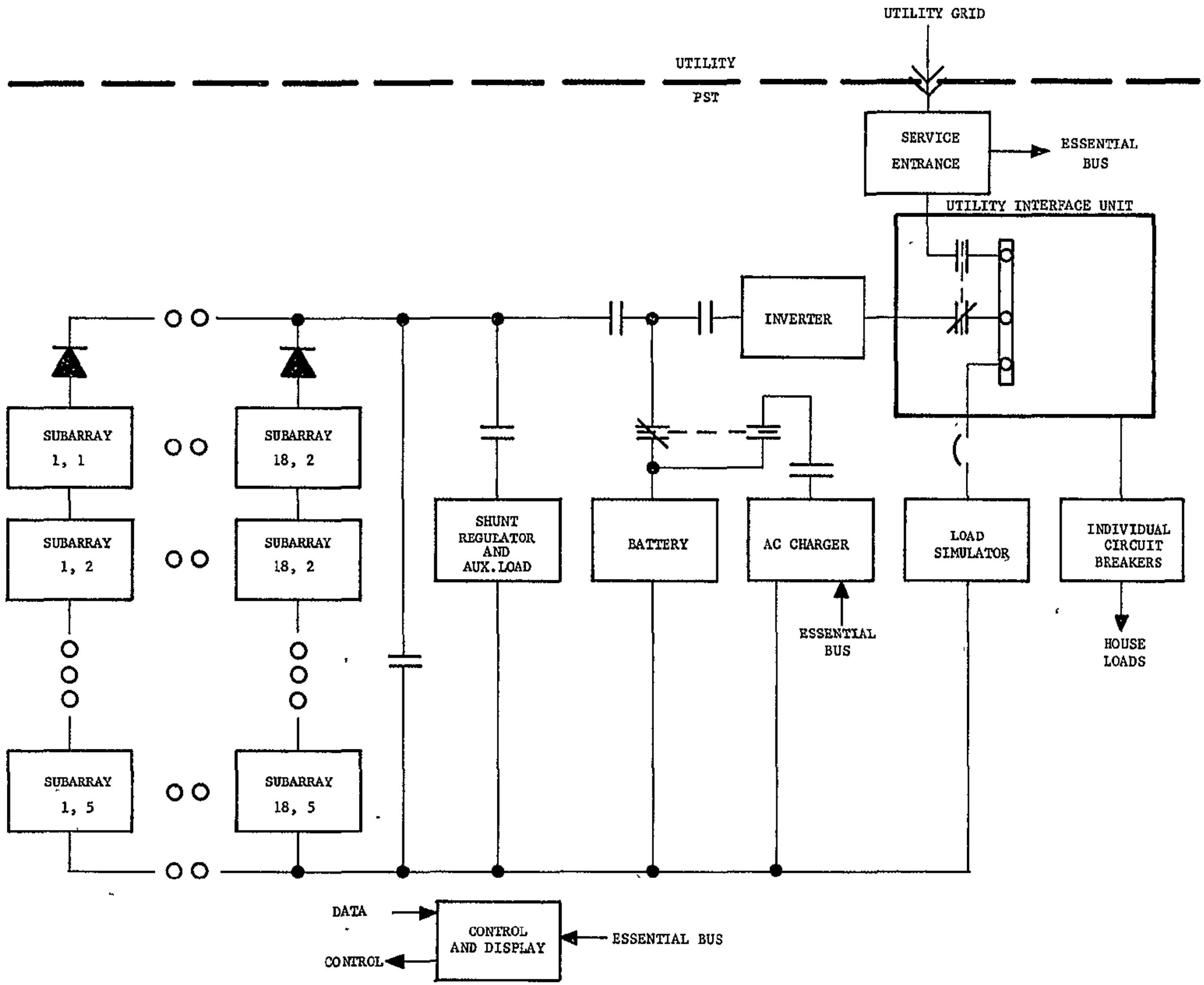

Figure D-2 Functional Block Diagram of EPS System with Battery, No Power Feed Back to Utility

1.4 Ground Rules and Assumptions

The test procedure was prepared based on the following criteria.

(1) All tests will be conducted at the regional PST. This does not preclude performing early tests at another location. However, a separate test procedure will be required.

(2) All hardware have been tested before delivery and require only minimum testing to verify that the units are functional.

(3) The battery cells are assumed to have been activated either at the manufacturer's plant or at the test site before the subassembly tests.

(4) The software required for both the data acquisition and control unit and the data reduction computer has been checked out.

(5) Test equipment includes only the portable equipment. This does not include that equipment mounted in major assemblies such as the data acquisition and control unit.

2. APPLICABLE DOCUMENTS

None applicable.

3. TEST PROCEDURE.

This test procedure contains the requirements for two types of tests to be performed on the PST power system. The first set of tests will verify the initial installation of the equipment. The remaining tests will gather data for evaluation of the hardware and system performance.

3.1 Subassembly Tests

These tests verify the performance of each battery and solar array subsystem module. The tests shall be performed and the data evaluated before module installation.

3.1.1 Solar Array Subassembly

The subassembly shall be attached to a tracking mount, oriented to the sun, and the temperature stabilized. A load stepper shall be used to provide at least 20 discrete points (no load to short circuit). The light intensity and the subassembly voltage, current, and temperature shall be recorded at each step on magnetic tape. These data shall be extrapolated to an I-V curve at AM1 and 28°C.

3.1.2 Battery Cell

After activation, the cells shall be charged at constant voltage until the charge current is reduced to the cutoff current. The charge voltage and cutoff current shall be as specified in the manufacturer's instructions. The cells shall then be discharged to 1.6 volts at a C/10 rate. This charge/discharge cycle shall be repeated twice except that on the third cycle a 48-hour open circuit stand shall be inserted after the charge. Cell voltage, current, and temperature shall be recorded each 10 minutes during charge and each three minutes during discharge. The data shall be recorded on magnetic tape and used to calculate watt-hours in, watt-hours out, ampere-hours in, and ampere-hours out.

3.2 Startup Tests

These tests will verify the readiness of each active element, subsystem, or component before using it for input, control, or loading of other equipment. The first five tests shall be performed in the order defined. The last two shall be performed after the preceding tests in any order.

3.2.1 Data Acquisition and Control

Checkout of the individual system components shall be performed in accordance with the appropriate operating manual(s). After component checkout, all data and command channels shall be tested. The data channels shall have a signal of the proper type (ac or dc) and magnitude applied. The signal presence at the computer interface shall then be verified. Command channels shall be tested by issuing each command and verifying the voltage presence at the sink or the operation of the commanded function.

3.3.2 AC Charger

The output of the ac charger shall be disconnected from the battery contactor, connected to the load simulator, and set up for maximum output power at 145 Vdc. Resistive loads shall be applied to the charger in steps representing approximately 10% of the rated current to 150% of full load. Record the voltage and current at each step and prepare a plot of current versus voltage.

3.2.3 Inverter/ac Charger

The ac charger shall be disconnected from the load simulator and connected to the inverter input. The load simulator shall be connected to the inverter output. For each inverter, the load simulator shall be set to open circuit and power will be applied to the inverter at 145 Vdc. The inverter shall be loaded, in steps of approximately 10% of the inverter kVA rating, to 100% of the inverter rating or the ac charger rating, whichever is less. The power factor at each step shall be varied from leading to lagging in five steps. If multiple inverters are used, this test shall be repeated for each. The inverter input current and voltage and the output current voltage and power shall be recorded for each load step. The VA, VAR, and inverter efficiency shall be calculated for each load step.

3.2.4 Battery/ac Charger

The ac charger shall be reconnected to the battery contactor. The power lead to the battery contactor from the solar array/inverter bus shall be disconnected and replaced with a connection to the load simulator. The battery charges shall be at a constant C/10 rate. Discharges shall be into a fixed resistance load set to give approximately the desired current at mid-discharge. Set the battery contactor to the ac charger and charge the battery for predefined time period or until the voltage reaches 2.4 Vdc cell whichever occurs first. The contactor shall then be transferred and the battery discharged at C/10 to 1.6 volts/cell. Three additional cycles shall be performed with nominal discharge rates of C/20, C/10, and C/5 respectively. The battery voltage, battery current, battery module voltage, and temperature shall be recorded each 10 minutes during charge and discharge. Plots of charge and discharge voltage and current shall be prepared. W-h in, W-h out, A-h in, A-h out shall be calculated. After the test, the load simulator shall be disconnected from the battery contactor and the power lead to the solar array/inverter bus reconnected. The battery shall be charged to 100% at C/10 before preceding.

3.2.5 Battery/Inverter

The load simulator shall be connected to the inverter output and set to no load. The battery shall then be connected to the inverter input. Loads shall be applied to the inverter, in steps of approximately 10% of the inverter kVA rating, to 100% of the inverter rating. To prevent excessive battery discharge, the time at each step shall not exceed five minutes. The power factor at each step shall be varied from maximum leading to maximum lagging in five steps. The inverter input current, output current, input voltage, output voltage, output power, and temperature shall be recorded for each load step. The VA, VAR and efficiency shall be calculated for each load step. These data shall be compared with the data obtained in 3.2.3. They will provide a baseline for later inverter evaluation.

3.2.6 Solar Array/Shunt Regulator

The solar array/shunt regulator bus shall be disconnected from the balance of the system for this test. The test shall be started approximately 30 minutes after sunrise. The forecast shall indicate at least an 80% probability of a cloud cover not exceeding 10 percent before noon (standard time). The solar array shorting switch shall be opened and the performance monitored throughout the daylight period. Each 10 minutes throughout the day solar array voltage and current, subarray voltage, current, and temperature, all intensity sensors, meteorological data, the shunt regulator input voltage and current, and the voltage and current delivered to the auxiliary load shall be recorded. The shunt regulator efficiency versus input power shall be plotted.

3.2.7 Utility Interface Unit

Inspect the system and verify that all system components are properly interconnected. Inhibit parallel operation of the inverter and utility grid and switch the load bus to the utility grid. A 300 to 1000 VA load shall be applied to each leg of the bus and the inverter started. Transfer commands shall be issued to transfer to the inverter and return. Each transfer shall be verified. With the inverter and utility power removed, parallel operation shall be enabled. Connect a dual beam oscilloscope across the inverter leg 1 to neutral and the utility grid leg 1 to neutral. Re-apply power and enable the inverter control unit. With the oscilloscope, verify that the inverter is synchronized and set the load simulator to a minimum of 110% of the inverter rating. Command the closing of the main switches and record the utility grid, inverter and load voltage, current and power. Calculate the respective VA and VAR.

3.3 Component Tests

Component tests are generally performed as part of the system test when included in the configuration. Only tests to be performed at the component level are identified.

3.3.1 Solar Array

Solar array testing includes monitoring the performance of the array and the meteorological and insolation conditions affecting the performance.

a. Power Output - The solar array voltage, current, and temperature shall be recorded during the daylight test hours. Calculate the array power and energy output. Record the output of the degradation sensors.

b. Meteorology - Record the wind velocity and direction, ambient temperature, relative humidity, and ambient pressure during each test.

c. Insolation

1. Daily - Record total intensity and hemispherical solar irradiance during all solar array tests.

2. Quarterly - As a special test each quarter, determine the direct irradiance during a two-day period under clear sky conditions. Record the sensor output each 15 minutes along with visual observations of the sky conditions.

3.3.2 Battery

a. Battery performance - Record the battery and module voltages and the current, and module temperatures during each test of configurations IIIB and IIIC. The power and energy shall be calculated for both charge and discharge.

b. Cell condition - Fully charge the battery each quarter. Measure the specific gravity of the electrolyte in each cell and its open circuit voltage. Discharge the battery at a nominal C/2 rate using the inverter and the load simulator. Repeat the specific gravity and open circuit voltage measurements.

3.3.3 Inverter

Record the inverter dc input voltage and current, the ac output voltage, current and power, and the inverter temperature. Calculate VA, VAR, power factor, ac energy out, dc power in, dc energy in and inverter efficiency. When multiple inverters are used (Configurations IIIB and IIIC), record the data and perform the calculations for each unit.

3.3.4 Shunt Regulator

The shunt regulator input voltage and current and the voltage and current delivered to the auxiliary load(s) shall be recorded. Calculate the shunt regulator efficiency.

3.3.5 Power Distribution Subsystem

a. Distribution Loss - Distribution loss for each cable segment shall be calculated monthly using data acquired during step loading of the system.

b. Contactor performance - Contactor performance shall be determined semiannually by using an oscilloscope (with camera) to determine the operating time of each switch and the noise generated. Current flow through the contacts shall be approximately 10% of the contact rating. If a significant change from previous tests is observed, the switch shall be repaired.

3.4 System Configuration Tests

3.4.1 PST and Utility without Battery (Configuration IIIA)

a. Setup

1. Open the contactors to disconnect the shunt regulator and battery from the solar array bus.

2. Enable the parallel operation of the inverter and utility grid.

3. Load (or select) the IIIA configuration in the data acquisition and control system.

4. Inhibit operation of the small inverter(s) and enable the inverter control unit.

b. Operation - The system is controlled by the data acquisition and control system. A programmed load sequence will be generated five times during the day with data recording increased to one record each minute during the period. During the remainder of the day, the system shall be supplying house loads, as controlled by the operator, and/or supplying the utility grid. The test shall start before sunrise and continue until after sunset.

c. Measurements - Data shall be recorded for the solar array, inverter, inverter control unit, and the distribution system.

d. Data Reduction and Analysis - Plots shall be prepared to show (with respect to time) the solar intensity, solar array peak power capability, solar array power out, inverter power and VAR out, utility power and VAR, and load power and VAR. Inverter efficiency shall be calculated at each load during the programmed loading. Load energy, inverter energy, and utility energy shall be computed.

3.4.2 PST and Small Battery without Utility (Configuration IIIB)

a. Setup

1. Close the battery contactors to connect the shunt regulator and battery to the solar array bus.

2. Disable parallel operation of the inverter and utility grid.

3. Load (or select) the IIIB Configuration in the data acquisition and control system.

4. Enable operation of all inverters and disable the inverter control unit.

b. Operation - The system is controlled by the data acquisition and control system. A programmed load sequence will be generated five times during the day with data recording increased to one record each minute during the period. During the remainder of the day, the system shall be supplying house loads, as controlled by the operator, and charging the battery or powering the auxiliary load. The test shall start before sunrise and continue until after sunset.

c. Measurements - Data shall be recorded for the solar array, inverter, shunt regulator, battery, and the power distribution system.

d. Data Reduction and Analysis - Compute the load energy, inverter energy out and utility energy. Determine the efficiency of the operating inverter during the programmed load period. Calculate the battery W-h and A-h efficiency and the shunt regulator and auxiliary load power and energy. Plot (with respect to time) the solar intensity, solar array peak power capability, solar array power out, inverter(s) power and VAR out, utility power and VAR, load power and VAR, battery voltage and current, and shunt regulator voltage and current.

3.4.3 PST and Battery without Utility (Configuration IIIC)

a. Setup

1. Close the battery contactors to connect the shunt regulator to the solar array bus.

2. Disable parallel operation of the inverter and utility grid.

3. Load (or select) the IIIC configuration in the data acquisition and control system.

4. Enable operation of all inverters and disable the inverter control unit.

5. The battery state-of-charge shall be at least 70% Recharge with ac charger, if required.

b. Operation - The system is controlled by the data acquisition and control system. The load profile will be controlled to a preprogrammed sequence and will be representative of the typical home for the day, season, and weather. The test shall be run continuously for 10 days.

c. Measurements - Data shall be recorded for the solar array, battery, shunt regulator, inverter, and power distribution system.

d. Data Reduction and Analysis - Compute all parameters for the battery, inverter(s), shunt regulator, and distribution system. Plot (with respect to time) the solar intensity, solar array peak power capability, solar array power out, inverter(s) power and VAR out, load power and VAR, battery voltage and current, shunt regulator voltage and current and, if transfer to the utility occurred, the utility power and VAR.

4. INSTRUMENTATION

Special instrumentation requirements are listed in Table D-1. Cost, quantity and availability are also defined.

Table D-1 Instrumentation Requirements

Instrument	Quantity	Cost, $	Availability
Eppley Model NIP Pyrheliometer and and Model EQM Equatorial Mount	1	2000	Off the Shelf
Eppley Model 2 Pyranometer	2	1000	Off the shelf
Percent Sunshine Detector (threshold detector on output of NIP)	1	1000	New Design

5. TEST EQUIPMENT

Test equipment, not included in the data acquisition and control subsystem, is shown in Table D-2.

Table D-2 Test Equipment Requirements

Component	Quantity
Hydrometer	1
Thermometer	1
Digital Voltmeter with dc, ac rms and ohms	1
Oscilloscope - Dual Trace	1

6. DATA ACQUISITION AND STORAGE DEVICES

All data which must be acquired daily or data requiring more than one or two hours to acquire on a periodic basis shall be digitized and recorded by the data acquisition and control system.

All inputs shall be sampled as follows: (1) each 10 to 20 seconds for limit checks or display update only; (2) each minute for a five-minute average; and (3) each five minutes average and record.

Data storage shall be on a 3200-foot, nine-track magnetic tape for a two-week period.

Manually acquired data shall be recorded on data sheets and input to the data acquisition and control system as a special record.

7. DATA REDUCTION AND STORAGE DEVICES

Data reduction shall be performed on a large scale batch processing computer, such as the CDC 6500 or UNIVAC 1108, with plot capability. The data from the data acquisition and control unit shall be separated into functionally related groups (i.e., solar array, battery, conversion and regulation, and distribution), converted to internal code, and stored as separate files with related data on magnetic tape. Software shall be developed to calculate and plot the functions defined below. The plot program shall permit plotting any parameter (calculated or measured), individually or in groups, with respect to time or any single valued parameter.

7.1 DC Power and Energy Calculations

DC power and energy calculations at any dc input/output shall be made using the following relationships:

Power

$$W_{DC} = V_{DC} \times I_{DC}$$

Energy

$$WH_{DC} = \sum_{i=1}^{n} V_{DC_i} I_{DC_i} \Delta t_i$$

where

W_{DC} = dc Power (watts)

WH_{DC} = dc Energy (watt-hours)

V_{DC} = dc Voltage (volts), co

I_{DC} = dc Current (amperes)

Δt = Time increment

7.2 VA, VAR, AC Energy Calculations

AC energy and reactive power calculations shall be made using the following relationships:

Volt Amperes

$$VA = V_{AC} \times I_{AC}$$

Volt Amperes Reactive

$$VAR = \left(VA^2 - W_{AC}^{\ 2}\right)0.5$$

Power Factor

$$PF = \cos^{-1}\left(\frac{W_{AC}}{VA}\right)$$

Energy

$$WH_{AC} = \sum_{i=1}^{n} V_{AC_i} I_{AC_i} PF_i \Delta t_i$$

where

VA = volt amperes

VAR = Reactive Power (volt amperes reactive)

PF = Power Factor

WH_{AC} = ac Energy (watt-hours)

V_{AC} = ac Voltage (volts)

I_{AC} = ac Current (amperes)

W_{AC} = ac True Power (watts)

t = Test time (hours)

7.3 Distribution Losses

Two methods shall be used to calculate distribution losses. The first method, which shall be used when the voltage monitors are located at the source and load ends of the line, is:

$$W_{cu} = \left(V_S - V_L\right) \times I$$

All other distribution loss calculations shall be:

$$W_{cu} = I^2 \times R$$

where

W_{cu} = Copper (distribution) Losses (watts)

V_S = Source end voltage (volts)

V_L = Load end voltage (volts)

I = Line Current (amperes)

R = Line Resistance (ohms)

7.4 Battery Parameter Calculations

The battery watt-hour and ampere-hour calculations shall be made using the following equations:

$$AH = \sum_{i=1}^{n} I_{B_i} \Delta t_i$$

$$WH = \sum_{i=1}^{n} V_{B_i} I_{B_i} \Delta t_i$$

where

AH = Battery Capacity (ampere-hours)

WH = Battery Energy (watt-hours)

I_B = Battery Current (amperes)

V_B = Battery Voltage (volts)

Δt = Time increment

7.5 Battery Voltage and Current Plots

When required, the battery voltage and current shall be plotted.

7.6 Inverter Efficiency

The inverter efficiency shall be calculated using the dc power in and the ac power out.

$$\eta_I = \frac{W_{ACI}}{V_{DCI} \times I_{DCI}}$$

where

η_I = Efficiency of Inverter

W_{ACI} = ac Power Out (true watts)

V_{DCI} = Input Voltage (volts)

I_{DCI} = Input Current (amperes)

7.7 Shunt Regulator Efficiency

The efficiency of the shunt regulator shall be calculated as:

$$\eta_{SR} = \frac{\sum_{i=1}^{n} \left(V_{AL_i} \times I_{AL_i}\right)}{V_{SR} \times I_{SR}}$$

where

η_{SR} = Efficiency of Shunt Regulator

I_{AL} = Auxiliary Load Current (amperes)

I_{SR} = Shunt Regulator Current (amperes)

V_{AL} = Auxiliary Load Voltage (volts)

V_{SR} = Shunt Regulator Voltage (volts)

7.8 Solar Irradiance Parameters

The formulas to be used for calculating solar irradiance parameters are:

Clearness Number

$$CN = \frac{I}{I_o \left(e^{-\tau \sec\theta_o}\right)}$$

Sky Diffused Irradiance

$H(s)p = H(d)h\ [1 + \cos(PT)]/2$

$H(d)h = H(t)h - I'$

$I' = I \cos \theta_o$

Ground Diffused Irradiance

$$H(r)p = H(p) - H(s)p$$

Ground Reflectance

$$\rho_g = H(r)p/\ H(t)h[1 - \cos\ (PT)]/2$$

Diffuse Solar Irradiance on Panel

$$H(d)p = H(p) - I \cos \theta$$

where

CN = clearness number

H(p) = Total solar irradiance on tilted panel (*)

H(d)h = Diffuse irradiance on horizontal surface (*)

H(r)p = Diffuse solar irradiance on panel from ground reflectance (*)

H(s)p = Diffuse solar irradiance on panel from the sky (*)

H(t)h = Total solar irradiance on horizontal surface (*)

I = Normal incident solar irradiance (*)

I_o = Extraterrestrial solar irradiance (*)

I' = Direct solar beam on horizontal surface (*)

PT = Panel tilt angle (degrees)

θ = Angle between panel normal and sun (degrees)

θ_o = Solar zenith angle (degrees)

ρ_g = Ground reflectance

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*(cal/cm^2 - min)