ERDA / JPL / 954698 - 77/1

Engineering Study of the Module/Array Interface for Large Terrestrial Photovoltaic Arrays

FINAL REPORT
JUNE 1977

SEP 1977
RECEIVED
NASA STI FACILITY
INPUT BRANCH

Work Performed Under
JET PROPULSION LABORATORY Contract No. 954698

for the
ENGINEERING AREA of the LOW-COST SILICON SOLAR ARRAY PROJECT

(ERDA/JPL-954698-77/1) ENGINEERING STUDY OF THE MODULE/ARRAY INTERFACE FOR LARGE TERRESTRIAL PHOTOVOLTAIC ARRAYS Final Report (Bechtel Corp.) 165 p HC A08/MF A01 CSCL 10A G3/44
N77-30609
Unclas
41994

BECHTEL CORPORATION, RESEARCH AND ENGINEERING OPERATION
SAN FRANCISCO, CALIFORNIA

ERDA/JPL-No. 954698-77/1
Distribution Category UC-63

ENGINEERING STUDY OF THE MODULE/ARRAY INTERFACE FOR LARGE TERRESTRIAL PHOTOVOLTAIC ARRAYS

Final Report

June 1977

Work performed under
Jet Propulsion Laboratory Contract No. 954698
for the
Engineering Area of the Low-Cost Silicon Solar Array Project

Prepared By

Bechtel Corporation
Research and Engineering Operation
50 Beale Street
P.O. Box 3965
San Francisco, California 94119

This work was performed for the Jet Propulsion Laboratory, California Institute of Technology, under NASA Contract NAS7-100 for the U.S. Energy Research and Development Administration, Division of Solar Energy.

The JPL Low-Cost Silicon Solar Array Project is funded by ERDA and forms part of the ERDA Photovoltaic Conversion Program to initiate a major effort toward the development of low-cost solar arrays.

This report contains information prepared by Bechtel Corporation under JPL sub-contract. Its content is not necessarily endorsed by the Jet Propulsion Laboratory, California Institute of Technology, the National Aeronautics and Space Administration, or the U.S. Energy Research and Development Administration, Division of Solar Energy.

12218

ACKNOWLEDGMENTS

This study was conducted as a team effort by members of Bechtel Corporation's Research and Engineering Operation. Overall management responsibility rested with T. E. Walsh, Manager of the Power Technology Group. E. Y. Lam served as the Project Manager and W. J. Stolte was the Project Engineer.

ABSTRACT

Bechtel Corporation has conducted a study of several factors contributing to the design of photovoltaic panels and their interface with the array. The study's emphasis was on large arrays, with a 200 MW central station power plant used for the baseline. Three major areas--structural, electrical, and maintenance--were evaluated.

Efforts in the structural area included establishing acceptance criteria for materials and members, determining loading criteria, and analyzing glass modules in various framing system configurations. Array support structure design was addressed briefly. Electrical considerations included evaluation of module characteristics, intermodule connectors, array wiring, converters and lightning protection. Plant maintenance features such as array cleaning, failure detection, and module installation and replacement were addressed.

PRECEDING PAGE BLANK NOT FILMED

CONTENTS

Section		Page
1	SUMMARY	1
2	INTRODUCTION	7
2.1	Report Format	8
2.2	Cost Data	8
2.3	Manufacturers' Data	9
3	PLANT DESCRIPTION	10
3.1	Terminology	10
3.2	Baseline Plant Features	10
4	STRUCTURAL CONSIDERATIONS	15
4.1	Acceptance Criteria	16
	4.1.1 Glass Design Criteria	17
	4.1.2 Steel Design Criteria	19
4.2	Loading Criteria	20
	4.2.1 Site Climatology	22
	4.2.2 Wind Speeds and Pressures	23
	4.2.3 Snow Loads	28
	4.2.4 Seismic Loads	28
	4.2.5 Thermal Loads	29
	4.2.6 Summary of Loads	30
4.3	Size Concepts for Modules and Arrays	31
	4.3.1 Array Size	32
	4.3.2 Module Size	34
	4.3.3 Module Frame	41
	4.3.4 Panel Impact Analysis	53
	4.3.5 Array Support Structure	55

PRECEDING PAGE BLANK NOT FILMED

CONTENTS

Section		Page
4.4	Sensitivity to Criteria Changes	60
5	ELECTRICAL CONSIDERATIONS	67
5.1	Electrical Components	67
	5.1.1 Modules	68
	5.1.2 Intermodule Connectors	71
	5.1.3 Converters	82
5.2	Array Sizing and dc Wiring	88
5.3	Voltage Transients	94
	5.3.1 Lightning Stroke Transients	95
	5.3.2 Lightning Flash Transients	102
	5.3.3 Converter Transients	103
	5.3.4 Protective Devices	103
	5.3.5 Insulation Level	105
6	MAINTENANCE	106
6.1	Array Cleaning	106
	6.1.1 Cleaning Methods	107
	6.1.2 Cleaning Economics	111
6.2	Panel Installation and Replacement	122
	6.2.1 Handling Methods	125
	6.2.2 Handling Costs	124
6.3	Failure Scenarios	129
	6.3.1 Failure Rates and Categories	129
	6.3.2 Failure Detection	132
	6.3.3 Replacement Economics	140
6.4	Warrantees	142

CONTENTS

Section		Page
7	CONCLUSIONS	144
8	RECOMMENDATIONS	149
9	NEW TECHNOLOGY	152

References

ILLUSTRATIONS

Figure		Page
3-1	Delineation of Terminology	11
4-1	Extreme-Mile Wind Speed Near Phoenix, Arizona	25
4-2	Risk Of Occurrence Of Various Winds Within Project Life	26
4-3	Module-Frame Configurations	36
4-4	Estimated Panel Structural Cost Versus Module Size	37
4-5	Glass Module Maximum Bending Stresses Using Linear Theory	40
4-6	Alternative Panel Configurations On A Typical Array	43
4-7	Module With Variable Support Conditions	44
4-8	Alternative Configuration For 4'x8' Modules	46
4-9	Computer Model For Type 'A' Panel	47
4-10	Computer Model For Type 'B' Panel	48
4-11	Maximum Glass Bending Stress In Type 'A' Panel	49
4-12	Maximum Glass Deflections In Type 'A' Panel	49
4-13	Maximum Glass Bending Stress In Type 'B' Panel	50
4-14	Maximum Glass Deflections In Type 'B' Panel	50
4-15	Maximum Bending Stresses In Panel Frames	52
4-16	Conceptual Array Support Frames	56
4-17	Detail For Upper Connection Concept	61
4-18	Detail For Lower Connection Concept	62
5-1	Module Quantity Versus Size	69
5-2	Module Current Versus Size	71
5-3	Intermodule Electrical Connector	78

PRECEDING PAGE BLANK NOT FILMED

ILLUSTRATIONS

Figure		Page
5-4	Connector Cost Versus Rating	80
5-5	Connector Cost Versus Module Size	82
5-6	Relative Converter Cost Versus Voltage	86
5-7	Array Wiring Schematic	90
5-8	Array Length	91
5-9	Interarray Wiring Costs	92
5-10	Wiring Cost Versus System Voltage	93
5-11	Isokeraunic Map of the United States	97
6-1	Array Washing Cost	112
6-2	Array Power Variation	113
6-3	Array Power Variation with Washing	114
6-4	Net Revenue Versus Wash Interval	115
6-5	Net Revenue Increase with Washing (35 Mills/kWh)	117
6-6	Net Revenue Increase with Washing (45 Mills/kWh)	117
6-7	Net Revenue Increase with Washing (55 Mills/kWh)	118
6-8	Net Revenue Increase with Washing (65 Mills/kWh)	118
6-9	Impact of Washing on Revenue	119
6-10	Panel Installation Equipment	123
6-11	Initial Installation Cost	127

TABLES

Table		Page
4-1	Recommended Load Combinations	21
4-2	Extreme Wind Speed Probability and Force Ratios	27
4-3	Maximum Bending Stresses in Modules	41
4-4	Influence of Edge Supports on Plate Stresses	45
4-5	Array Support System Member Sizes	57
4-6	Influence of Height on Column Frames	59
4-7	Variations in Loading Parameters	64
5-1	Connector Cost	77
5-2	Range of Lightning Stroke Currents	96
5-3	Resistivity of Different Soils	101
6-1	Automated Washer Capital Cost	110

Section 1

SUMMARY

This report presents the results of an engineering study conducted by Bechtel Corporation. The purpose of the study was to analyze the solar module/array interface from the point of view of the installer and maintainer of such equipment. The study was directed at the analysis of large, terrestrial photovolatic solar arrays, such as would be used in a central station power plant. The analysis was divided into three major areas: structural, electrical and maintenance.

A hypothetical 200 MW central station power plant in the Phoenix area was selected as a baseline for purposes of this study. Results of the study are generally applicable to other installations of a similar size. The modular nature of the needed converter equipment led to a plant configuration wherein the power from groups of arrays forms the dc input to each of the converter modules dispersed throughout the array field. Power from the converters is transported to a plant substation via a 34 kV ac wiring network.

The arrays considered herein are nontracking and consist of flat panels fastened to an array framework at an inclination of 33° to the horizontal. The panels are in turn comprised of one or more solar cell modules. Three panel sizes (2x4 foot, 4x8 foot and 8x16 foot) are evaluated in detail. However, many of the results

are presented graphically as a function of panel size. It is desirable to have vehicle access between the arrays to facilitate installation and maintenance operations. Selecting an interarray spacing (which is proportional to array cross section) to provide for vehicle access led to an array cross section with a 16-foot hypotenuse. Also, this size array accepts the three panel sizes studied in even multiples, thereby facilitating comparison.

Because of their ready availability and desirable characteristics, steel and glass materials were selected for purposes of this study. Glass has attractive physical properties for the solar module construction, giving protection and structural support to the encapsulated photovoltaic cells. Steel provides the stiffness needed for proper support of glass modules and is readily fabricated into the required structural configurations. Design criteria for these materials were defined for this study.

The loading criteria and load combinations used herein were defined in accordance with the ANSI A.58.1-72 Building Code. The parameters for wind, snow and seismic forces were defined for the Phoenix area and critical loads were established for various glass thicknesses. A unit value of 50 psf was used subsequently for the parametric studies reported here. For the Phoenix region this design load is governed by the wind criteria.

The baseline structural concept examined herein is for prefabricated 8x16 foot panels being attached to a simple array

support structure, where each panel is an assembly of 4x8 foot glass modules in a supporting steel framework.

Finite element computer models were used for many of the structural studies. Results of the parametric studies are reported for the glass modules, for the support frames interacting with the glass, and for the array support structures. These studies show that readily available steel sections (e.g., TS 6x3x1/2 for panel frames and wide-flange shapes for array frameworks) and normal glass thicknesses can be used for these structures. Frame members must provide minimum levels of stiffness to ensure adequate edge support for the glass and thereby keep the stresses in the glass within allowable limits. A panel structure was analyzed for in-plane forces caused by edge impact simulated by using 2 g's deceleration body forces and showed the resulting stresses to be non-critical.

A review of loading criteria for extreme values that occur in other geographical locations of the U.S. showed that the design load can increase to 102 psf and that the structural changes for the steel and glass required by such increased loads are minor. Thus, the basic structural concepts developed herein are readily adaptable to other locations.

Electrical considerations included evaluation of converters, intermodule connectors, array wiring, voltage transients and the relationship of these areas to module design. Converter costs, a

major contributor to plant cost, decrease with increasing system voltage. A system voltage of 2500 volts is recommended. For this voltage, it is estimated that converters will contribute $0.06 per watt to the plant cost. The term "watt" used throughout this report refers to the peak power output of the module, panel or array. Final selection of system voltage should include analysis of module cost versus system voltage. These data are unavailable at present.

Consideration of cost and ease of installation led to selection of a factory-installed, quick-disconnect type connector to accomplish the intermodule connections. Cost considerations in this area favor large module sizes. Module current on the order of 50 amperes was selected to ameliorate possible internal wiring and encapsulation difficulties. For a 4x8 foot module with an open circuit voltage of 8 volts, it is estimated that installed connectors will cost about $0.01 per watt.

Array wiring costs and panel installation costs also favor selection of large panels. At the moment, anticipated module production techniques suggest limiting modules to about the 4x8 foot size. The configuration selected consists of four 4x8 foot modules factory assembled into an 8x16 foot panel. The arrays are then wired with two series strings of modules per array. At a 2500 volt system voltage each array is about 1250 feet long. Analysis of converters and a postulated lightning protection system concluded that array terminals and

modules at this system voltage might be exposed to transient voltages on the order of 8 kV. Lightning protection and selection of a converter are system design features addressed briefly herein and need to be reevaluated in greater detail before module insulation levels are finalized.

Maintenance functions addressed include array cleaning, failure detection, and panel installation and replacement. An automated array cleaning method was postulated and shown to be economically justified in most instances. Benefits derived from cleaning depend on the rate of dirt accumulation and the value of the energy sold.

Initial installation costs for the panels, estimated in conjunction with replacement procedures, are on the order of $0.01 per watt for the 8x16 foot panels and about four times that amount for the 2x4 foot panels. A current monitoring scheme is proposed to detect complete module failures. A cursory economic analysis indicates that these modules should be replaced as failures occur. Methods are also proposed to detect less severe open intercell wiring within a module; but for the postulated module design, replacement is not warranted.

Conduct of this study has led to selection of module and system design features optimized (as far as available data permit) from the viewpoint of the installer and maintainer of a plant. It has also produced cost estimates for the design features considered

as a function of module size and system voltage. These cost data can be combined with similar estimates for modules and system design to optimize life cycle cost.

Section 2

INTRODUCTION

In order to provide for the future energy needs of the United States, the Energy Research and Development Administration is fostering the development of energy sources such as solar power. As a part of this effort, the Jet Propulsion Laboratory (JPL) is conducting a program to develop Low-cost Silicon Solar Arrays (LSSA). In addition to developing solar cells and manufacturing techniques, the LSSA program is addressing aspects of solar cell module design important to the effective integration of the modules into electric power systems.

The Research and Engineering Operation of Bechtel Corporation has conducted an engineering study addressing the latter aspect of module design. In particular, Bechtel's study considered the interface between the modules and arrays from the point of view of an installer and maintainer of such systems. The emphasis of the study was on large array systems such as would be used in a central station power plant or equivalent large industrial applications. Structural, electrical and maintenance aspects of the module/array interface were addressed. This report presents the results of that study.

2.1 REPORT FORMAT

This report has been prepared in the format specified by JPL Document Number 1030-26, Rev. B. Section 3 presents a brief description of a 200 MW plant assumed for the baseline in this study. Structural aspects of the study are addressed in Section 4. The electrical aspects are presented in Section 5. Section 6 presents discussions on maintenance aspects. Conclusions and recommendations resulting from the study are presented in Sections 7 and 8, respectively. Section 9 contains a statement that no new technology has been identified by this study.

2.2 COST DATA

Several cost estimates are included in the report. The accuracy of these estimates is commensurate with the level of detail in an engineering study.

For the most part, costs estimates were derived in 1977 dollars. These estimated costs were subsequently translated into terms of 1975 dollars in order to facilitate their use and comparison in other areas of the LSSA program. A factor of 9 percent inflation on commercial products (supplied by JPL) was used to convert early 1977 dollars into mid 1975 dollars for purposes of this study.

Some of the cost data are normalized to terms of dollars per watt. This watt is taken to be the peak power output of a module, panel, or array and corresponds to 10 watts per square foot. Thus, dollars per watt may be translated into terms of dollars per square foot by multiplying by 10. Similarly, the cost per module or panel can be obtained by multiplying the dollars per square foot by the module or panel size in square feet. With this simplifying assumption, no allowances are made for losses of power in wiring, connectors, converter equipment, etc.

2.3 MANUFACTURERS' DATA

Conduct of the study involved evaluation of vendors' literature and contact with several manufacturers in relation to needed items of equipment. The subsequent naming of manufacturers in conjunction with the discussions of components and equipment does not necessarily constitute an endorsement of the equipment, nor does it imply that these manufacturers have been selected to supply the related items. Rather, it is intended to point out that versions of the necessary equipment are commercially available.

Section 3

PLANT DESCRIPTION

To a large extent, the design of a photovoltaic solar cell module is governed by the intended end use for the module. This study addresses design features for modules in large-scale, terrestrial applications, such as central station power plants. Thus, rudimentary concepts for a 200 MW plant (developed in a previous study sponsored by ERDA/Sandia/Spectrolab, Inc., Ref. 1) were used to provide a baseline from which module design can proceed. A brief description of the baseline plant is presented in this section. A brief description of terms used herein is also provided.

3.1 TERMINOLOGY

During the conduct of this study, it was found that terms such as module or panel do not have a universal and consistent meaning among the many entities engaged in solar programs. To avoid confusion, the meanings given to such terms within this report are delineated in Figure 3-1.

3.2 BASELINE PLANT FEATURES

In order to provide a baseline from which the study could proceed, a design for a hypothetical 200 MW central station power plant located in the Phoenix area was postulated. Design

CELL - a single silicon wafer (or ribbon) photocell with a nominal ½ volt output.

MODULE - an encapsulated, self-supporting assembly of cells, with internal series and parallel wiring terminated by two wires (plus and minus) emerging from the unit.

PANEL - a self-supporing, shippable assemby of modules. In the limit, a panel may consist of a single module. A four-module panel is illustrated.

ARRAY - an assembly of panels fastened to a support framework at the site and field wired. An array may support more than one series string of modules. Each module string is wired to reach full system voltage.

ARRAY GROUP - arrays electrically interconnected to supply power to a single power conditioning unit, PCU, (i.e., converter). Arrays within the group are paralleled to obtain the current level desired for the converter.

ARRAY FIELD - the aggregate of all arrays within the plant.

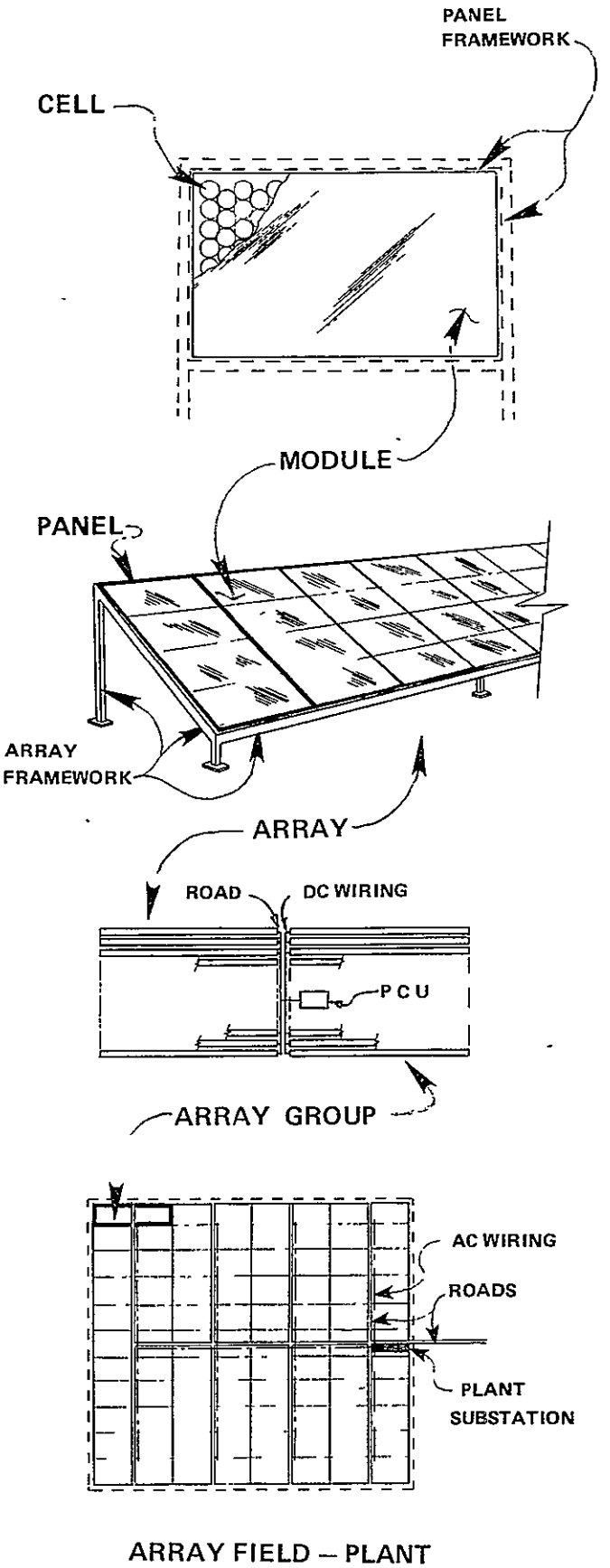


Figure 3-1 DELINEATION OF TERMINOLOGY

features for a plant of this general nature were developed by Bechtel in a previous study (Ref. 1). The results of that study were utilized where applicable.

This study is based on 10 watts peak output per square foot of array surface. Thus, 2×10^7 square feet of array area are needed for the 200 MW plant. The array field consists of 1677 individual non-tracking, flat plate array structures. Each array has a sloped surface width of 16 feet and is inclined at an angle of 33° to the horizontal. The length of the array is determined by the dc system voltage selected. For an array spacing distance equal to the array height (approximately 9 feet) the site area is approximately 1.3 square miles. The arrays consist of 4 foot by 8 foot solar cell modules (nominal 8 volts open circuit per module), factory assembled into 8 foot by 16 foot panels and fastened to a structural framework. Each array contains two module series strings having an open circuit voltage of 1500 volts each. The two module strings are connected in parallel to form a single pair of array terminals. Both array terminals (plus and minus) are located at the same end of the array structure.

The dc outputs of three adjacent arrays are connected in parallel via an underground tapered bus. This underground wiring connects the outputs of 13 adjacent tapered busses to one of 43 power conditioning units distributed throughout the array field.

Each power conditioning unit contains a converter, ac output filters, an output transformer, a control and data acquisition system, and, possibly, an energy storage battery. The converter, nominally rated at 4000 amperes, converts the dc output of the array (and storage battery) into a 60 Hertz ac waveform compatible with the utility network.

The filtered output of the converter is delivered to the plant switchyard via a 34 kV wiring system. At the switchyard, the voltage is stepped up to 230 kV for connection to the utility transmission line.

The control and data acquisition system consists of a microcomputer connected via a data link to a central computer located in the central control room. The system monitors converter and array operating parameters, and controls the converter to track array characteristics for variations in insolation and temperature.

The system design also includes switchgear, protective relaying, grounding and lightning protection systems, and other auxiliary systems required for proper plant operation and protection. Also, shops, warehouses, and other maintenance facilities are provided as required.

For this study, major perturbations to the baseline plant described include higher system voltages (and therefore longer arrays) and various module sizes.

Section 4

STRUCTURAL CONSIDERATIONS

A major feature of the solar photovoltaic plant is the relative simplicity of the power generating equipment. Flat, photovoltaic panels are held on array structures at an angle suitable for the incident solar flux at the latitude of the power plant. The panels and their supporting structures are generally lightweight in comparison with the substantial structures needed to support heavy equipment in a conventional steam power plant. This structural simplicity contributes to attaining the goal of low cost. However, special attention must be paid to details and to proper structural functioning, since these structures are repeated many times to achieve the required power levels. This section presents several aspects of the structural requirements and suggests practical concepts for the construction of the solar photovoltaic panels and arrays.

The design of a structure always requires the initial definition of design criteria. The two basic aspects of this are the specification of loads and load combinations, and the specification of the acceptance criteria for the materials and members involved in the structures. Accordingly, this section began by considering the criteria to be used for evaluation of the design concepts. These criteria were taken from existing building codes and handbooks since no unified code is available

specifically for conventional power plant structures, least of all for the unique power plant being considered here.

4.1 ACCEPTANCE CRITERIA

The materials used for the manufacture of contemporary solar photovoltaic modules include various plastics, glass, steel and aluminum.

Extensive experience has been reported for the use of glass used in space and terrestrial solar photovoltaic applications (Ref. 2). This experience has generally been satisfactory. When used for space applications, glass protects individual cells against particles and radiation, filters out ultraviolet radiation, and provides temperature control. However, for terrestrial applications, glass is required to give structural support as well as physical protection. Glass has a temperature coefficient of expansion compatible with that of steel, has a very low moisture permeability, has no ultraviolet degradation with time, and is readily available in commercial quantities at reasonable cost. Based on these considerations this work was confined to considering solar modules made from annealed float glass. However, since this glass has low impact resistance, suitable tests should be made to qualify glass module designs.

In addition, the structural framing material was assumed to be ASTM A-36 steel, readily available in a wide range of standard

sections at cost levels influenced by a large marketplace. Aluminum was not considered since weight reduction was not an important factor in the structural concepts and the combination of aluminum sections with steel fasteners and concrete foundations could induce cathodic corrosion.

4.1.1 Glass Design Criteria

Criteria for glass materials were derived from available handbooks for engineering with glass (Ref. 3). Annealed float glass was assumed for the modules and average properties selected for the structural investigations are as follows:

Elastic Modulus	10000 kips/in^2
Poisson's Ratio	0.2
Weight of 1/4" plate	3.28 psf

Only approximate ranges are available for the working stress levels of different glasses. This is because the ultimate strengths for glasses vary much more than for metals. Before failure, glass behaves in a linear elastic fashion and fails suddenly in a brittle manner. Failure is always due to a tensile component of stress even when the load is compressive. The ultimate strength is sensitive to the distribution of flaws in the glass and also exhibits a gradual decrease with time. This static fatigue, or creep, is not changed very much by applying a cyclic loading over the same period of time. For these reasons, the working stresses are derived by applying large safety factors

to average ultimate strengths. Typical values for working stresses for two common types of glass are as follows:

Type of Glass	Working Stress	
	Tension	Compression
Annealed	500 - 1500 psi	5000 - 10,000 psi
Tempered	1500 - 4000 psi	5000 - 10,000 psi

Values higher than the above are recommended for smaller components and lower values are recommended for more massive components. Shear strength is not critical for glass since the tensile failure behavior dominates. However, a conservative value of allowable shear would be to use a value equal to the allowable tensile stress.

This approach to establishing allowable stresses for glass is consistent for applications where the structural behavior is linear and thus where elastic analysis is applicable. However, observations of the behavior of window glass installations subjected to environmental wind loads show that the glass sheets respond with substantial membrane action induced along with the bending. This is because the glass deflections are observed to reach large values compared to the glass thickness. A useful approach is to use elastic analysis in conjunction with apparent or effective allowable stresses. Accordingly, if the window glass sizes which are recommended (Ref. 5) are analyzed elastically using a plate formula with aspect ratio of 2.0, then the apparent allowable stress may be deduced. This apparent

stress varies with glass thickness since the membrane stresses, or diaphragm action, vary with thickness. The apparent allowable stresses for float glass windows, using a breakage probability of 8 per 1000 panes, are listed below:

Glass Thickness (inches)	Apparent Allowable Stress (ksi)
1	2.3
3/4	2.7
1/2	3.2
1/4	5.3
1/8	8.1

It can be seen that the thin glass sheets have a larger portion of the strain energy involved in membrane action; hence the apparent allowable stress is much higher than typical working stress levels. Similarly, the membrane action diminishes for the thicker glass and the apparent allowable stresses tend towards values closer to typical working stresses. The stresses listed above are used in this work to evaluate the glass modules in conjunction with linear elastic structural analyses. These stress criteria must be reevaluated for specific glasses in actual module designs used for prototype construction.

4.1.2 Steel Design Criteria

For the development of the structural support concepts, a commonly used steel, ASTM A-36, was assumed. The design of steel components is governed by the criteria given in the AISC Manual of Steel Construction (Ref. 5).

4.2 LOADING CRITERIA

The necessary load definitions and their combinations follow the guidelines given in ANSI A58.1-1972, "Building Code Requirements For Minimum Design Loads in Buildings And Other Structures" (Ref. 6). The loads recognized for this work and their symbols are defined and summarized below.

Dead Loads (D) include the weight of all permanent construction for glass modules, steel support structures, and fixed service equipment needed for plant operations.

Live Loads (L) are loads imposed from usage of the structure, such as loads from maintenance and cleaning operations, water or brush pressures, and gantry loads. This set also includes snow loads. For the purpose of this work the total load of a cleaning gantry was assumed to be 1000 lb. A uniform pressure of 3 psf was assumed to result from maintenance operations on the glass.

Wind Loads (W) are the forces due to wind pressures.

Earthquake Loads (E) are due to site seismic excitations.

Thermal Loads (T) are loads and forces due to overall thermal changes in the system structures.

Table 4-1 lists the 11 cases of load combinations used for this study. These combinations are derived from the guidelines given in ANSI A58.1-1972, Section 4.0 (Ref. 6). This list shows the factors by which the loads are multiplied to allow for the probability of simultaneous occurrence of the maximum effects from these loadings. These combinations assume that there are no changes in the design allowable stresses of members and materials. The site-related loads are discussed in more detail in the following sections.

Table 4-1

RECOMMENDED LOAD COMBINATIONS

CASE	LOAD TYPES D	L	W	E	T
(1)	1.0	1.0			
(2)	1.0		1.0		
(3)	1.0			1.0	
(4)	1.0				1.0
(5)	.75	.75	.75		
(6)	.75	.75		.75	
(7)	.75	.75			.75
(8)	.75		.75		.75
(9)	.75			.75	.75
(10)	.66	.66	.66		.66
(11)	.66	.66		.66	.66

4.2.1 Site Climatology

The selection of design wind and snow pressures is closely related to the prevailing climatological character of the construction site. For this work, the location of the 200 MW baseline plant is postulated in the southwestern desert near Phoenix, Arizona. Accordingly, the weather records and wind data for that region were reviewed (Refs. 7, 8).

Moisture bearing winds sweep into Arizona from the southeast, the Gulf of Mexico, to provide summer rainfalls from July to September. These summer rains mostly occur in the form of thunderstorms which are largely caused by excessive heating of the ground. This causes lifting of the moisture-laden air along the mountain ranges. These thunderstorms are often accompanied by strong winds and periods of blowing dust before the onset of rains. Hail occurs infrequently. High winds accompanying heavy thunderstorms during July and August have been known to reach peak gusts of 100 mph in local areas (Ref. 7). During the 50 years from 1916 to 1965 a total of 58 tornado funnels were reported of which 33 touched the ground. Only two deaths due to tornadoes were reported in this period.

Only a trace of snow is ever observed in the Phoenix area and available records show a maximum recorded snowfall of 1 inch in January 1937 (Ref. 8). Accordingly, the snow loads derived in

this work represent a nominal allowance for that geographical region.

4.2.2 Wind Speeds And Pressures

Two approaches were used to arrive at a recommended wind speed for design of the glass modules. The first approach used the ANSI Code (Ref. 6) directly. This is a conventional method which gives limited information about the risk aspects involved. In order to expand on this, the approach described by S.C. Hollister (Ref. 9) was also followed and is included here. The basic wind speed charts used for this work are those derived by H.C.S. Thom (Ref. 10) and which are the national basis for wind speed estimates. These wind speed charts give the annual extreme-mile wind speed at 30 feet above the ground for selected mean recurrence intervals. Using the standard charts (Refs. 6, 10), the wind speeds at Phoenix are estimated for several mean recurrence intervals as follows:

Recurrence Interval (Years)	Wind Speed (mph)
25	67
50	72
100	78

The selection of the recurrence interval is related in the code to risk to human life. A 100 year interval is normally recommended for a structure where there is a high degree of hazard to life and property in case of a failure. Where there is

negligible risk to human life, a 25 year interval is acceptable. Even though there is no human occupancy in the solar collector field, a special consideration is the relative fragility of the glass photovoltaic modules and the economic significance attached to continued functioning of the glass panels. This therefore leads to using the 100 year recurrence interval for the Code method and gives a design wind of 80 mph for Phoenix.

The Hollister method leads to the same result but expands on the risk aspects. First the complete series of wind speed charts given by Thom (Ref. 10) are used to give an extended set of wind speed values at Phoenix. These are plotted on special probability chart paper as shown in Figure 4-1 so that the site extreme-mile wind speed is given for any recurrence interval.

An economic life of 25 years was assumed for this solar equipment and this gave a basis for determining the risk of occurrence of other winds of different recurrence intervals using probability methods. This procedure is described by Hollister and the basic probability relationships are given in Figure 4-2 (Ref. 9). The mean recurrence intervals, each corresponding to a specific risk of occurrence, are read from Figure 4-2 for the 25 year equipment life. These are converted to extreme-mile wind speeds by Figure 4-1 for Phoenix. The wind velocities and their risks of occurrence are listed in Table 4-2. The 80 mph design wind is seen to have a 20% risk of occurrence during the 25 year life of this equipment. Since the wind pressure varies as the square of

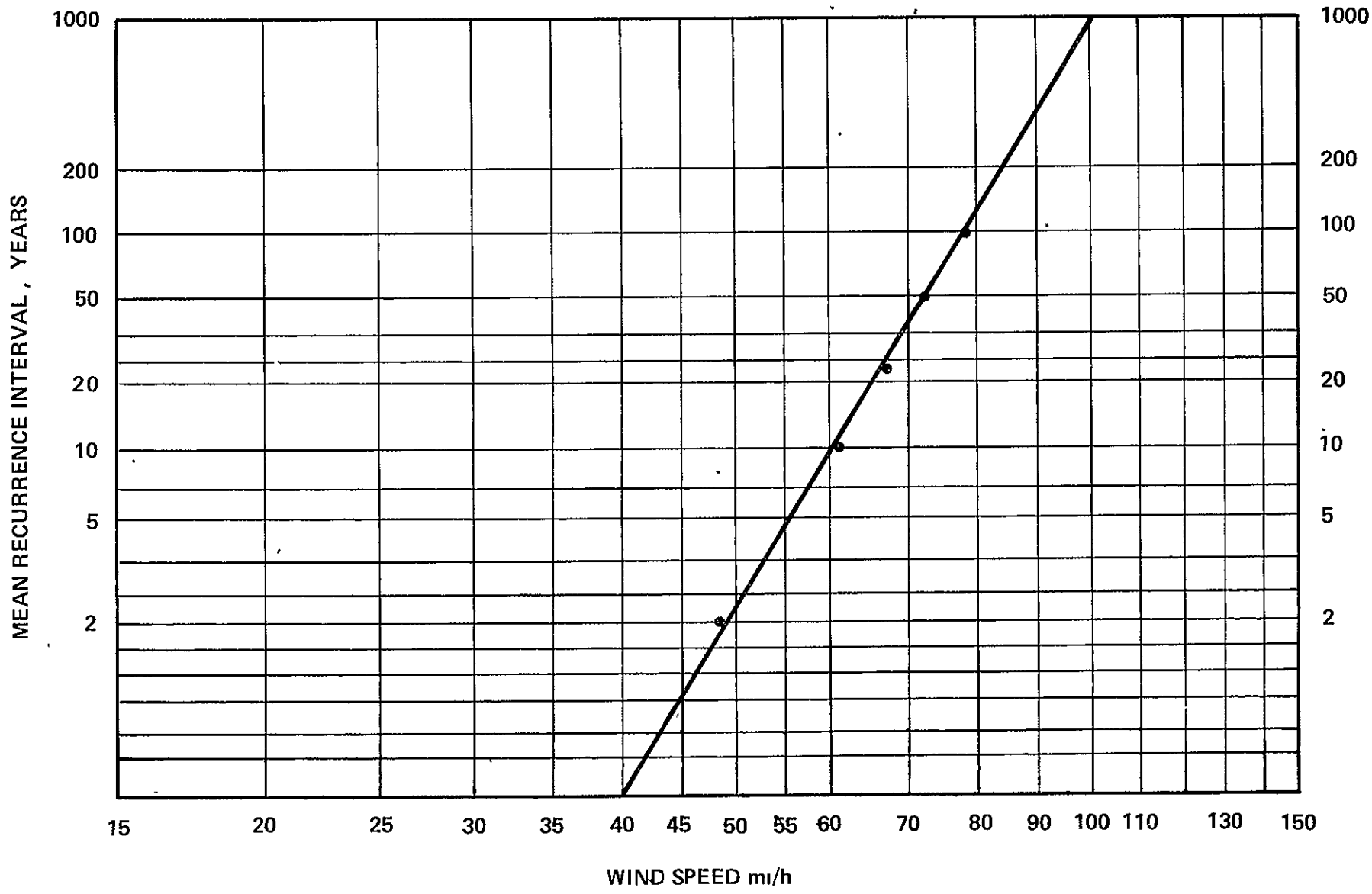


Figure 4 - 1 EXTREME - MILE WIND SPEEDS NEAR PHOENIX, ARIZONA

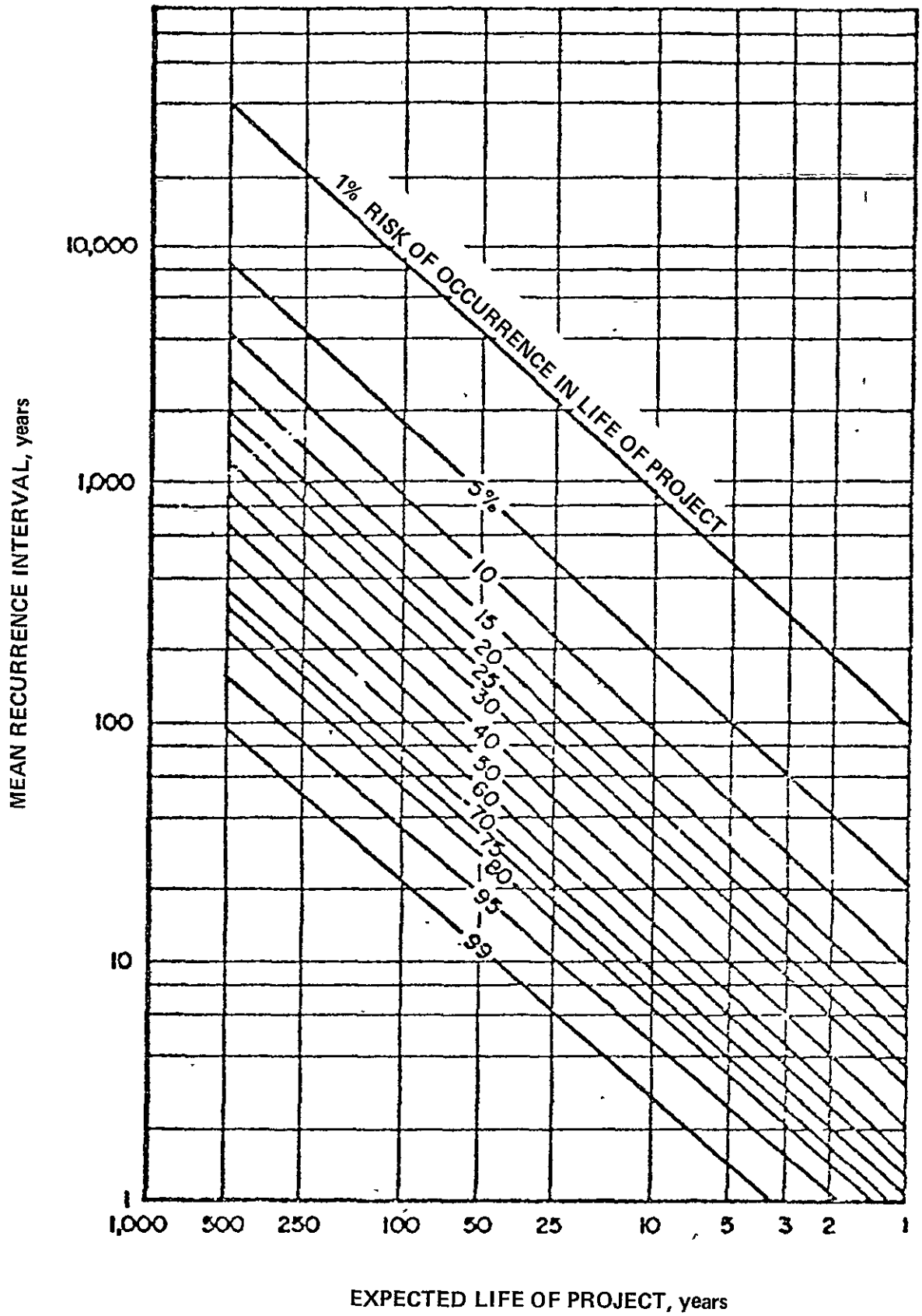


Figure 4 - 2 RISK OF OCCURRENCE OF VARIOUS WINDS WITHIN PROJECT LIFE

the velocity, the corresponding changes in wind forces can be derived as force ratios. These are given in Table 4-2. If 80 mph is used as the design datum, the risk of occurrence of a 90 mph wind is 6% with a 26% increase in wind force. Similarly there is a 2% risk of experiencing a 100 mph wind and this would give a 56% increase in wind force.

Table 4-2

EXTREME WIND SPEED PROBABILITY AND FORCE RATIOS

Extreme-mile Wind Velocity mph	Risk of Occurrence %	Velocity Ratio	Wind Force Ratio
100	2	1.25	1.56
95	3	1.19	1.41
90	6	1.12	1.26
85	10	1.06	1.13
80*	20	1.00	1.00

* Selected design speed for Phoenix area at allowable stress levels.

Selection of the 80 mph extreme wind is therefore recommended as an appropriate strategy for the wind load specification. Probability analyses (Ref. 9) indicate that the 80 mph extreme-mile wind has a gust factor of 1.28, a gust component of 18 mph, and is associated with an hourly mean speed of 62 mph. The ANSI Code method is used to transform wind speed to incident pressures. The resultant normal force for the glass panels sloping at 35° to the horizontal is 35 psf. This includes a 5% increase for wind fluctuations.

4.2.3 Snow Loads

Snowfall records for the Phoenix area (Ref. 8) indicate that a maximum of 1 inch of snow was recorded in 1937. That depth corresponds to about 0.5 psf loading. Snowload charts given in the ANSI Code (Ref. 6) were therefore used to determine a nominal load for design purposes. The average of the 50-year and 100-year mean recurrence intervals is 5 psf and this is used for this work.

4.2.4 Seismic Loads

The most recent criteria established for structural design against seismic forces can be found in the Uniform Building Code (UBC), 1976 Edition (Ref. 11). Accordingly, this Code was adopted for the seismic criteria used in this work. The basic procedure was to determine the base shear, V, as a fraction of the structural weight, W. The following formula is given in the Code:

$$V = ZIKCSW$$

where Z = seismic zone coefficient
I = occupancy importance factor
K = horizontal force factor
C = structural period factor
S = site-structure resonance factor

The UBC Code provides that the product CS need not exceed 0.14 and this was assumed for this work. By requiring that the array

support structures be designed as ductile moment frames, the K value is taken as 2/3. The seismic zone coefficient, Z, for Phoenix (designated by the UBC as being in seismic Zone 2) has a value of 3/8. Finally the occupancy importance factor, I, varies from 1.0 to 1.5 depending on the building function and the significance of its functioning after an earthquake. A factor I = 1.5 is used for essential facilities such as hospitals, schools, fire and police stations which must remain in operation after an earthquake. An occupancy importance factor of 1.0 was assumed for this design of the photovoltaic module structures. The products of these factors gives the base shear

$$V = 0.037W$$

If the vertical seismic acceleration is taken to be 2/3 of the horizontal value, the seismic design accelerations for these structures at this site are

horizontal	4% g
vertical	3% g

4.2.5 Thermal Loads

The temperature range assumed for these structures represents a reasonable assessment of seasonal variation at this site. The bounding values used for this were derived from available weather records for Arizona (Ref. 7). These showed minimum/maximum temperatures for the entire state of -37°F/127°F. However, these

were from different locations; the low reading coming from mountain heights and the high reading from the hottest desert region. The corresponding minimum/maximum temperatures for Phoenix are 16°F/118°F and these were taken as a suitable basis for this study. In addition, an increase of 50°F above the ambient air was assumed for these structures while operating with full insolation in still air. The final design temperatures are

minimum	=	16°F	or	-9°C
maximum	=	168°F	or	76°C
temperature range	=	152°F	or	85°C

4.2.6 Summary of Loads

D	Dead loads:	
	Glass plate, per inch of thickness	13.12 psf
	Steel sections	variable
L	Live loads:	
	Snow loads on panels	5 psf
	Maintenance of panels	3 psf
	Washer gantry weight, total	1000 lbs
W	Wind loads:	±35 psf
E	Seismic forces:	
	Horizontal	4% g
	Vertical	3% g
T	Temperature of structures:	
	Minimum	16°F (-9°C)
	Maximum	168°F (76°C)

4.3 SIZE CONCEPTS FOR MODULES AND ARRAYS

A basic consideration is to develop a simple and efficient structural system to support the glass photovoltaic modules under the specified loadings. Two aspects of the structural system are readily identified. There is the module support structure, or framing system, that transfers the glass module reactions to the array support structure and provides protection to the glass during handling and shipping. Then there is the array support structure that transfers the system resultant forces to the foundations. There is no natural separation between the module framing system and the array structural systems, except as the designer visualizes what is needed. It is eventually a matter of design judgment based on detailed knowledge of preferences in manufacturing processes and in field construction methods. However, two principles were invoked to guide this study.

Firstly, for economic reasons, it is desirable to maximize the shop fabrication and assembly operations and thereby minimize the field operations leading to fully installed structures. Extensive experience in the design and construction of major facilities supports the intrinsic value of using shop fabrication for the largest possible amount of work and delivering assembled packages or systems to the site for a minimum of field work. Whereas this is particularly important for adverse site geographies and climates, it remains very important even for the best of conditions.

Secondly, the function of the structures must be clearly identified so that structural adequacy is provided and structural redundancy minimized. For this reason the array support structure was given some attention in this work even though the major direction concerned the glass modules and their framing systems.

4.3.1 Array Size

Two general structural system concepts were considered, as follows:

(a) The field system includes the array support structure and module framing system complete. Glass modules with minimum edge framing treatment are then field assembled into the array frames.

(b) A simple, minimum array support structure is erected in the field. Glass modules are assembled into a frame system in the factory. The frame-module assemblies are attached to the array supports as a field operation.

The type (a) approach is consistent with contemporary methods for installation of windows in large buildings. Most of the structure is completed, sometimes with shop fabricated sub-assemblies brought together at the site, then the glass units are added in the field. This method is suitable for the installation

of the photovoltaic modules but has the disadvantage of requiring many more field operations than the type (b) approach.

The type (b) approach maximizes the shop-handling of glass modules and their support frames and thereby reduces field construction. For this method, it was also assumed that array support column-frames were shop welded, that support beams could be field bolted or field welded, and that module-frame assemblies would have simple attachments to the array beams.

To facilitate installation and maintenance, it is desirable to provide for vehicle access between the arrays. This interarray spacing is proportional to the width of the array. For purposes of this study a 16 foot array surface width was selected. This width is compatible with the three representative panel sizes (2x4 foot, 4x8 foot, and 8x16 foot) selected for evaluation in that these sizes fit onto such an array cross section in even multiples. This facilitates comparisons of alternate electrical designs and installation methods. The length of the array is set by consideration of electrical parameters, as discussed in Section 5.2, and does not influence the structural calculations, except for consideration of thermal expansion joints (as discussed in Section 4.3.5).

The selection of a structural concept for a prototype clearly depends on owner and contractor preferences. The type (b) approach was adopted as a basis for this study work.

4.3.2 Module Size

The approach used here was to select initial dimensions that matched practical considerations and then investigate framing and support requirements to see what structural limitations should be recognized. This approach establishes orders of magnitude for structural members and identifies critical areas needing special attention in the structural design of prototypes.

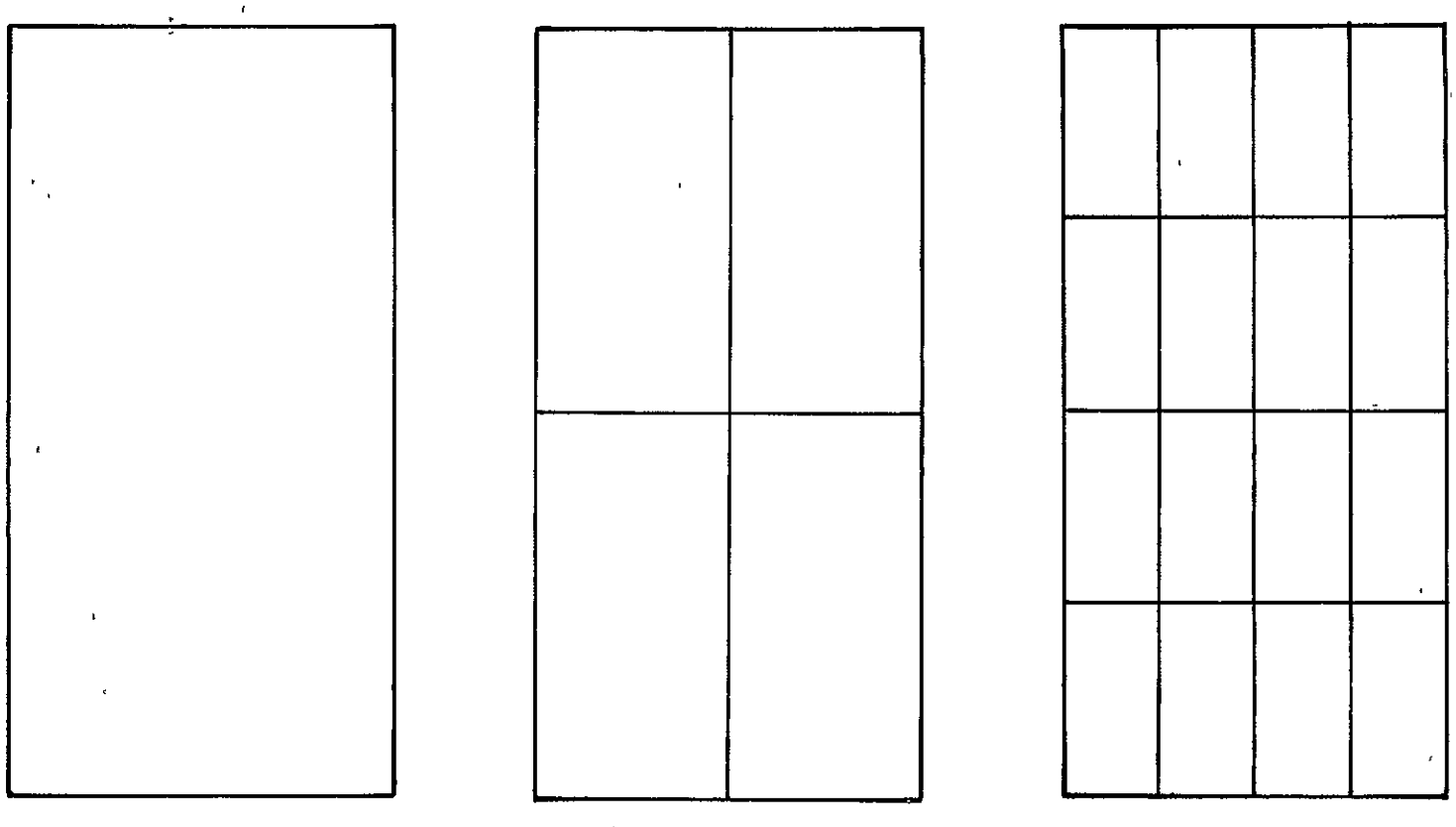
A glass photovoltaic module is visualized as a glass plate carrying the silicon cells encapsulated on the lower surface. The structural analyses that follow regard the glass module as a simple rectangular glass plate and ignore any structural contributions from the attached photovoltaic materials or encapsulants other than the glass.

A basic assumption used in this part of the study was that present-day limitations on physical size for glass modules would not be used to govern the concepts. The fact that, at present, the largest terrestrial photovoltaic modules typically provide about 5 square feet of surface area was not used as a size limit. It was assumed that photovoltaic modules can be manufactured in larger sizes when the technical specifications are established. Furthermore, glass manufacturers can provide regular plate glass up to 3/4 inch thick in sizes to 10x20 foot. Thicker plates may be limited to about 6x12 foot and a typical limit for tempered glass is 3x8 foot (Ref. 3). No limitation was assumed for the

glass module size owing to present availability of glass sizes expected to be used for this application. Again, it was assumed that the glass industry could produce special sizes in large production runs when the demand is established.

Several possible module-frame combinations are shown in Figure 4-3 to cover an 8x16 foot panel area. They vary from a single 8x16 foot glass module with a simple frame, to a pattern that uses 2x4 foot modules. Some basic manufacturing parameters listed with those diagrams are total length of steel frame sections, the number of frame joints, and the number of glass edges. These parameters relate directly to material or labor cost increments.

To assist in selecting a baseline module size for this study, costs were estimated for the three module-frame configurations shown in Figure 4-3. Only three cost contributions (glass, steel, and welding) were considered. Factors such as fastening modules to the panel were not included. The estimate was made to provide a preliminary indication of how costs vary with module size. The order-of-magnitude estimated costs presented in Figure 4-4 should not be interpreted as the cost of an optimized panel structure that may be achieved by judicious selection of structural sections to provide the edge support derived in the following sections of this report. The data in Figure 4-4 indicate that a panel comprised of four 4x8 foot modules would be a reasonable baseline configuration.



1 -- 8′ x 16′ MODULE	4 – 4′ x 8′ MODULES	16 – 2′ x 4′ MODULES
48 ft OF STEEL	72 ft OF STEEL	120 ft OF STEEL
4 FRAME JOINTS	10 FRAME JOINTS	34 FRAME JOINTS
48 ft GLASS EDGES	96 ft GLASS EDGES	192 ft GLASS EDGES

Figure 4 - 3 MODULE – FRAME CONFIGURATIONS

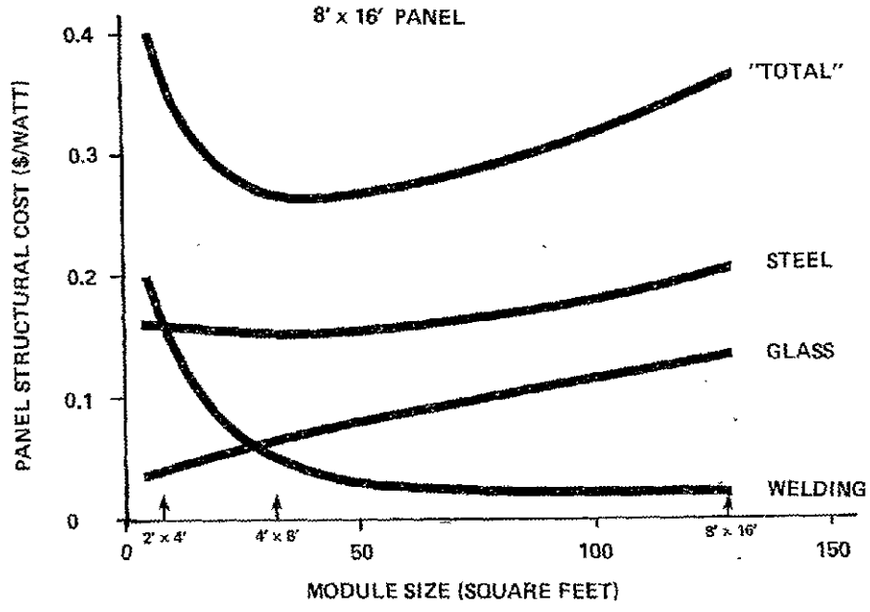


Figure 4 – 4 ESTIMATED PANEL STRUCTURAL COST VERSUS MODULE SIZE

A large rectangular plate element found widely in all kinds of facilities and construction is the 4x8 foot standard sheet. It is clear that this size and shape has established a successful history in applications and for handling in the industrial environment. This is not to say that a 4x8 foot size is 'ideal,' but it provides a useful starting point for sizing a large photovoltaic module. Choosing larger module sizes can be expected to reduce the anticipated ease of handling but will require more detailed investigation, which includes an analysis of module fabrication cost as a function of module size. Based on available data on automated module assembly, a 4x8 foot module was selected as a reasonable baseline size. For reasons of

shipping and installation economics (discussed in Section 6.2.2), it is postulated that four such modules would be factory assembled to form an 8x16 foot panel.

A typical 4x8 foot glass module was considered to be simply supported along each edge by the steel frame, and a series of calculations were made to determine the glass thickness. This calculation is nonlinear since the dead load varies with the selected thickness of glass, and so several trials must be made to determine the thickness needed to satisfy allowable stress criteria. The loadings and their combinations were as follows:

Dead load D	=	10 psf for 3/4 inch glass (varies with glass thickness)
Live load L	=	8 psf (snow and maintenance)
Wind load W	=	±35 psf
Seismic load E	=	0.5 psf (.05 D resultant)

The load combinations are checked to find the critical loading, as follows:

D + L	=	18 psf
D + W	=	45 psf (maximum)
D + E	=	11 psf
0.75(D + L + W)	=	40 psf
0.75(D + L + E)	=	14 psf

Note that a conservative approach is taken here by adding the wind and dead load forces directly, regardless of directions of action. These results indicate that wind governs the design and the critical design loading is 45 psf for 3/4 inch thickness. By repeating this for other glass thicknesses, the critical load is

derived for each. Assuming a perfect simple support along each edge of a module, maximum stresses are calculated using classical linear equations (Ref. 12). For rectangular plates whose sides have the aspect ratio 2.0, the maximum bending stress, σ, is given by:

$$\sigma = 0.6102\ p\ (b/t)^2$$

where
p = uniform pressure force
b = length of short side
t = glass thickness

The stress results for three module sizes are listed in Table 4-3 and are shown plotted in Figure 4-5. Preliminary glass thicknesses for these modules and a 35 psf wind force are thus indicated to be

1/8 inch glass for 2x4 foot modules
3/8 inch glass for 4x8 foot modules
7/8 inch glass for 8x16 foot modules

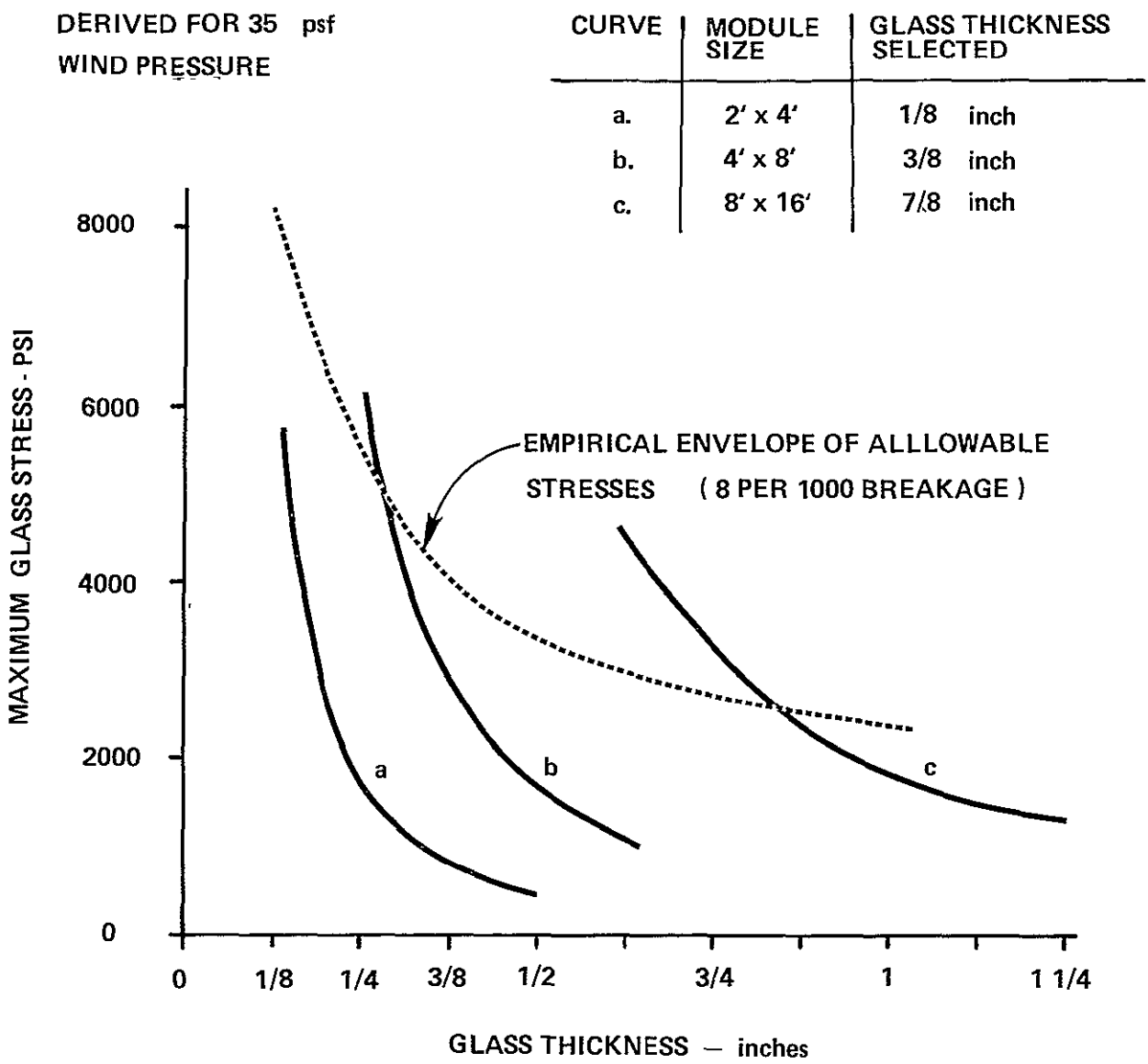


Figure 4 — 5 GLASS MODULE MAXIMUM BENDING STRESSES USING LINEAR THEORY

Table 4-3

MAXIMUM BENDING STRESSES IN MODULES

Glass Thickness (inches)	Critical Load (psf)	Linear Theory Bending Stresses (psi)		
		2'x4'	4'x8'	4'x16'
1/8	36.7	5720		
1/4	38.3	1496	6000	
3/8	40	694	2777	
1/2	42	410	1640	
5/8	43.2	270	1080	4320
3/4	45	195	781	3124
1	48.1		439	1757
1-1/4	51.4		321	1285
1-1/2	54.7			949

4.3.3 Module Frame

The structural frame for the glass modules has two basic functions: to transfer the operational loads to the array support structure; and to provide support to the glass modules against shipping and handling forces. The operational loads are essentially forces applied perpendicular to the glass surfaces whereas the handling loads are largely in-plane forces due to suspending the panels from one edge. These forces are considered separately in the following discussion.

Using the 4x8 foot module as a practical base unit of size, a panel can be assembled from 4 modules to give an 8x16 foot unit as shown in Figure 4-3. It was decided that this panel size represented about the largest practical unit for handling and shipping. Consequently the parametric studies of frame-module interaction assumed this size of panel. Three possible

configurations for the assembly of 4x8 foot modules into 8x16 foot panels are illustrated in the schematic of Figure 4-6.

The scoping analysis for glass modules assumed simply supported edges for the plates, but this also implies that the edges are supported by infinitely stiff beams. The frame members actually provide flexible support to the module edges in a prototype situation. The effects of this edge support flexibility was analyzed as follows. A 4x8 foot by 3/8 inch thick glass plate was analyzed with a unit pressure of 50 psf for the three edge support conditions shown in Figure 4-7. The flexible edge beams are represented by several steel sections which provide the beam section moments of inertia (I) listed with the maximum plate stresses in Table 4-4. Tubular sections are recommended for the module frames in preference to the I-sections because (a) they have high torsional stiffness and so better resist panel warping forces; (b) the tubes have smooth edges, which gives greater safety to personnel; (c) there are no re-entrant corners to catch moisture and so the potential for corrosion is reduced. However, channel sections are typically used in these kinds of frameworks.

It is clear that there is a region where the plate stresses are a function of the edge beam bending stiffness and this will hold true for the modules in a frame assembly. The prototype frame design must be arranged to provide a proper level of stiffness rather than simply satisfy allowable stress criteria for the steel.

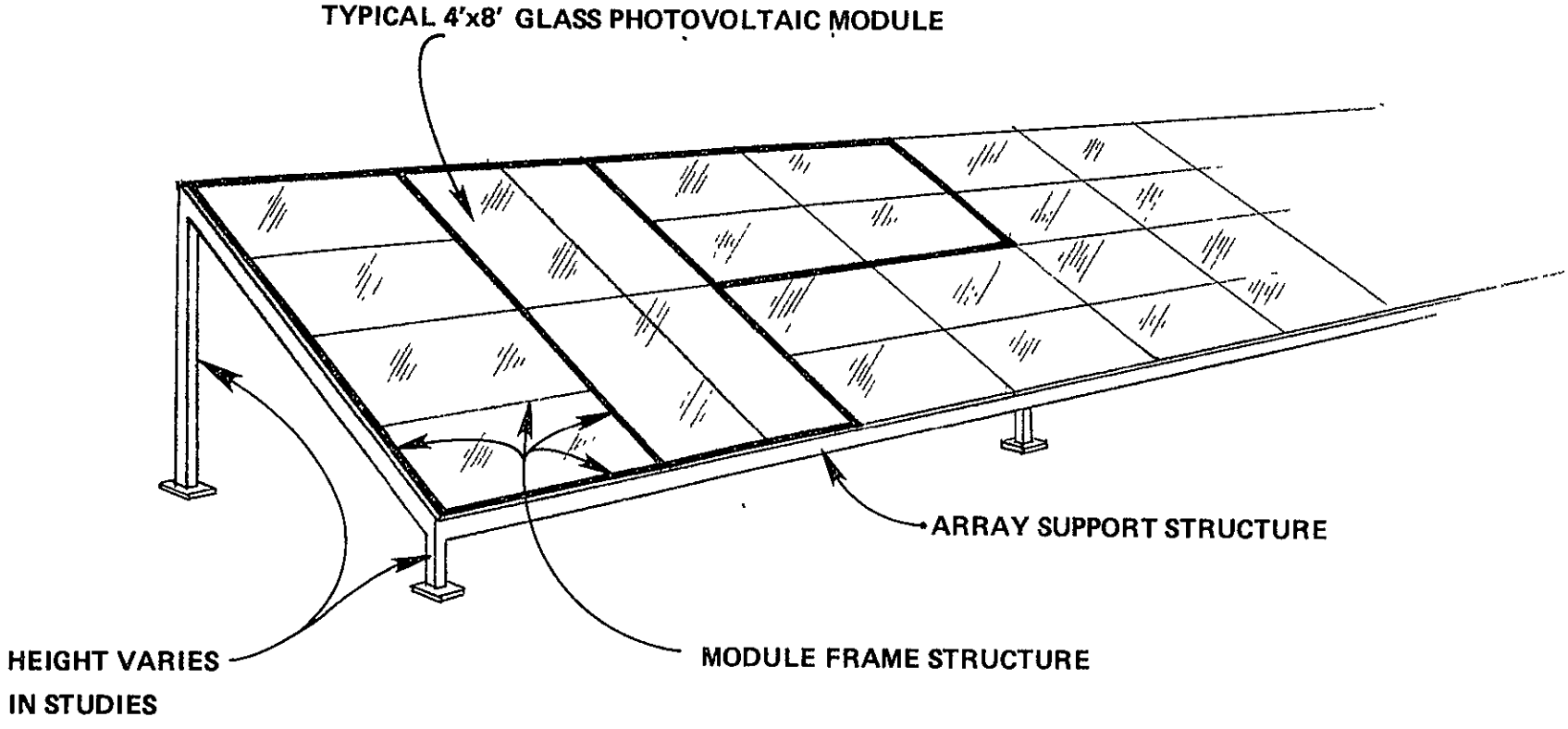
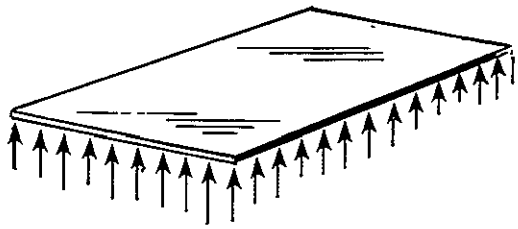
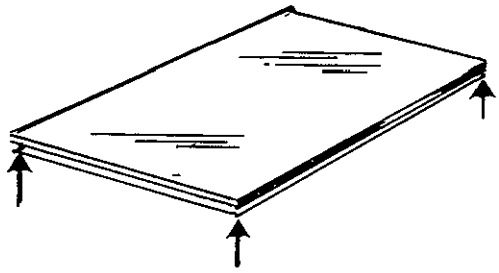


Figure 4 - 6 ALTERNATIVE PANEL CONFIGURATIONS ON A TYPICAL ARRAY



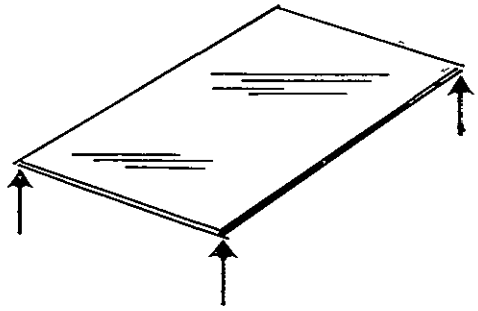
CASE (A)

SIMPLE SUPPORT ALL EDGES ; EQUIVALENT TO CORNER SUPPORTS & INFINITELY STIFF BEAMS



CASE (B)

CORNER SUPPORTS WITH FLEXIBLE EDGE BEAMS



CASE (C)

CORNER SUPPORTS ONLY AND NO EDGE BEAMS

4' x 8' x 3/8" GLASS PLATE FOR EACH CASE, WITH 50 psf UNIT LOAD

Figure 4-7 MODULE WITH VARIABLE SUPPORT CONDITIONS

Table 4-4

INFLUENCE OF EDGE SUPPORTS ON PLATE STRESSES

Beam Section I in^4	Maximum Module Stress psi
∞ *	3381
25.8	3379
12.6	3377
6.9	3374
0.7	3313
zero	17,624

* This case uses simply supported edges

This work was extended to analyze two panel configurations of 4x8 foot modules. These are shown in Figure 4-8 in an arrangement where the panels rest on the mid-span of an array support beam so that this source of flexibility would be included in the analysis. For each case it was assumed that the frame was fabricated from a single type of steel section. Results were computed for a unit load of 50 psf and these are interpolated for other loadings. The analytical model layouts are shown in Figures 4-9 and 4-10 for these panels. Each panel model uses quadrilateral shell elements along with three-dimensional beam elements. The Bechtel computer program CE 800-BSAP was used for the parametric study. The stress and deflection results are shown for the glass modules in Figures 4-11 through 4-14.

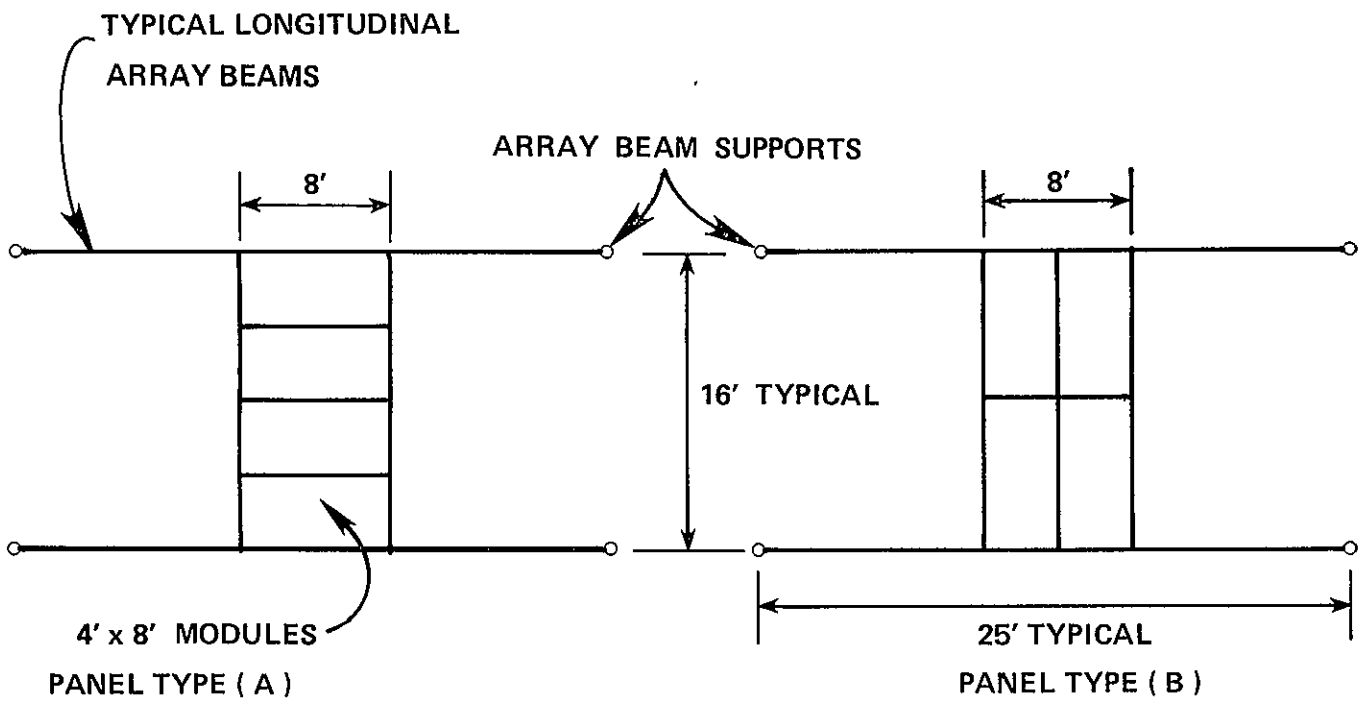


Figure 4-8 ALTERNATIVE PANEL CONFIGURATIONS FOR 4' x 8' MODULES

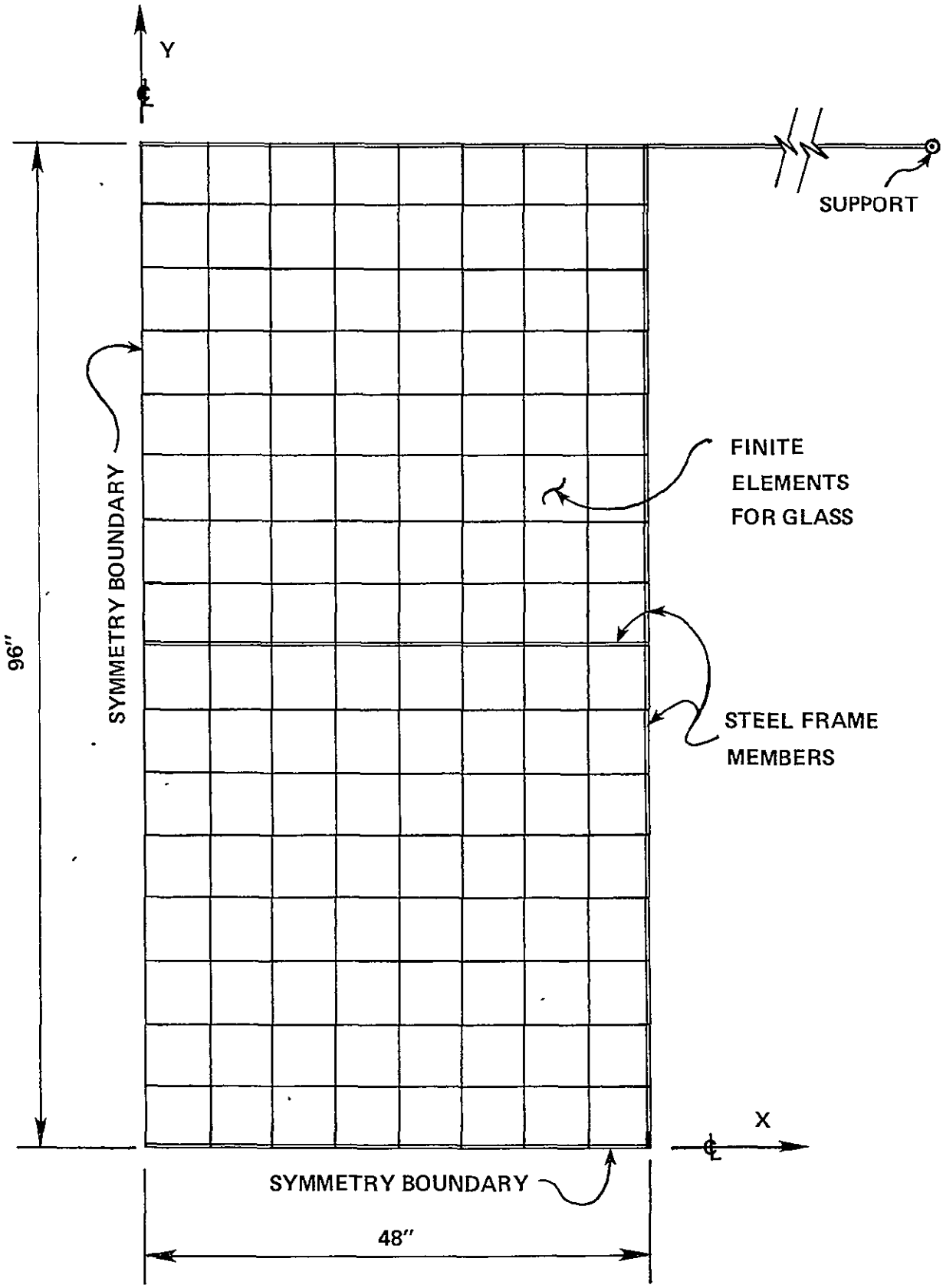


Figure 4-9 COMPUTER MODEL FOR TYPE 'A' PANEL

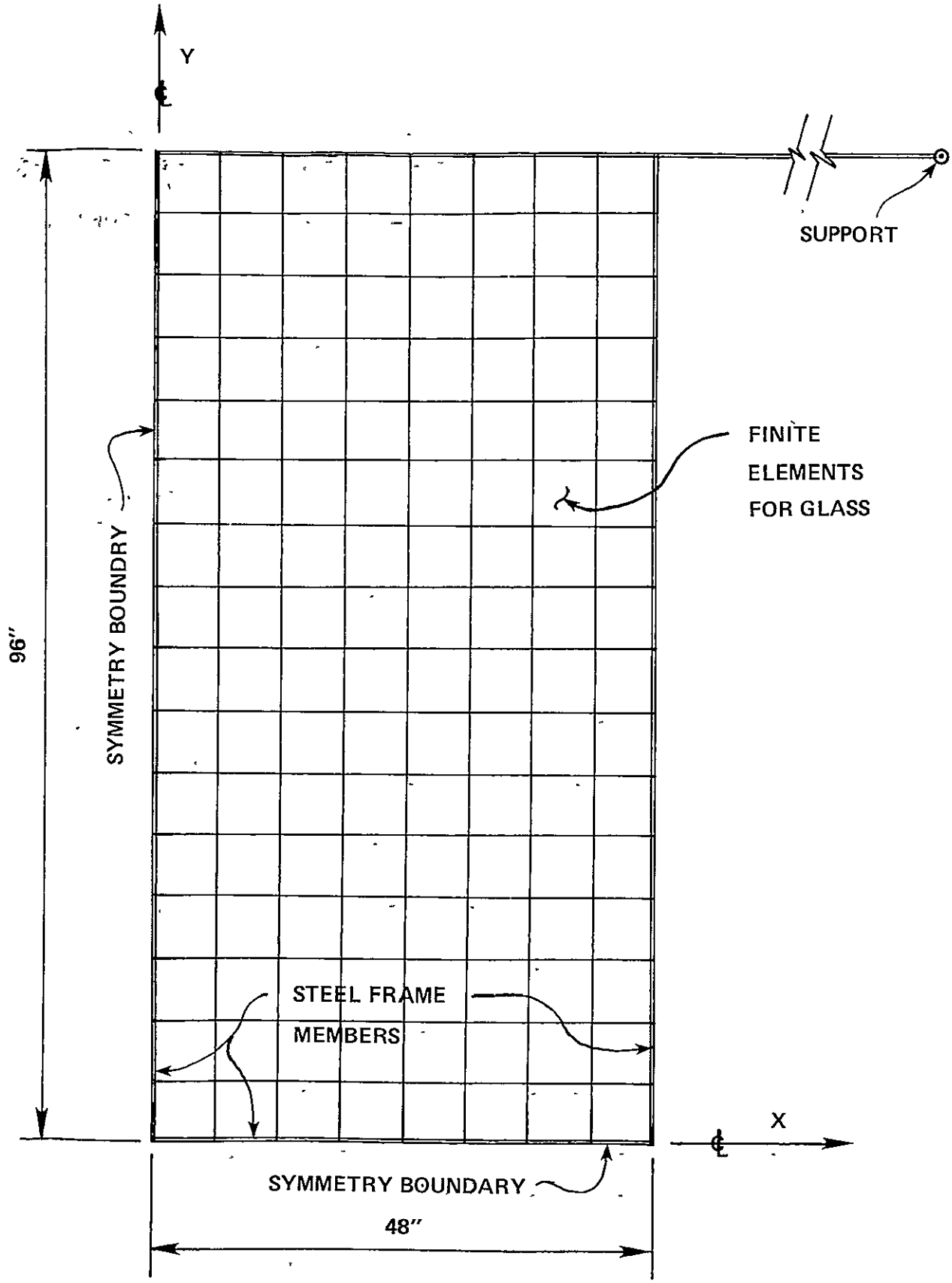


Figure 4-10 COMPUTER MODEL FOR TYPE 'B' PANEL

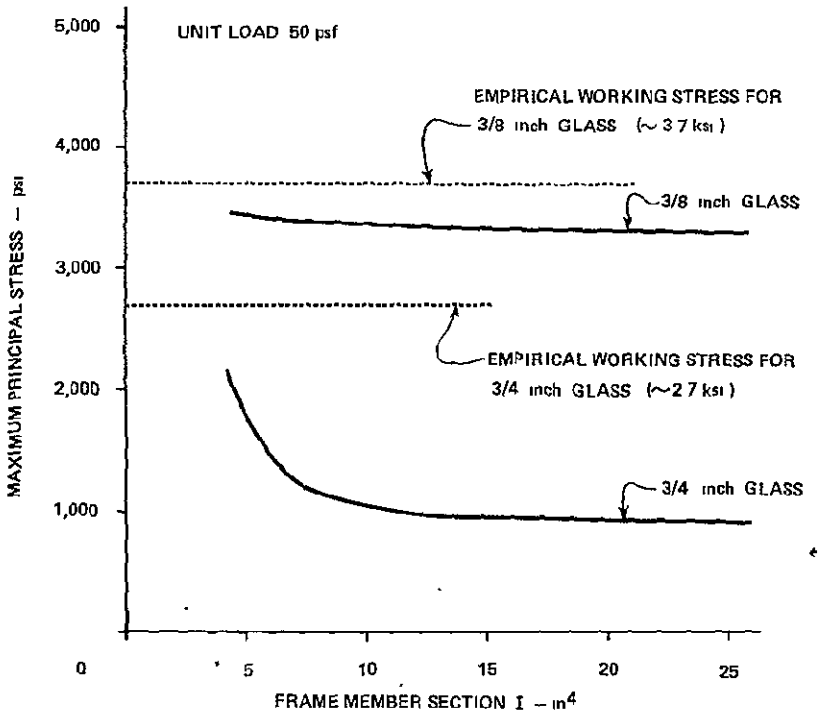


Figure 4–11 MAXIMUM GLASS BENDING STRESS IN TYPE 'A' PANEL

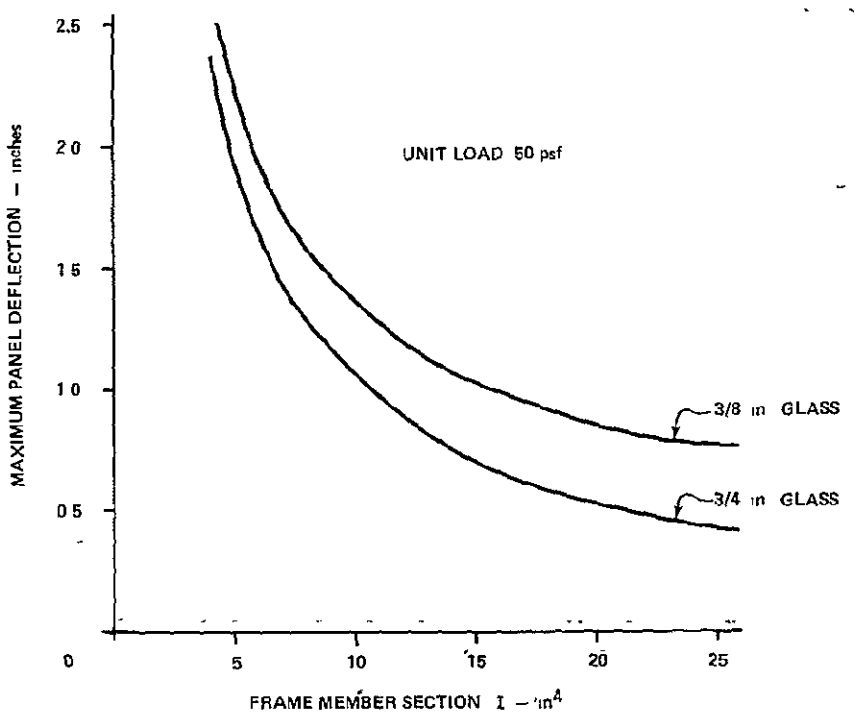


Figure 4–12 MAXIMUM GLASS DEFLECTIONS IN TYPE 'A' PANEL

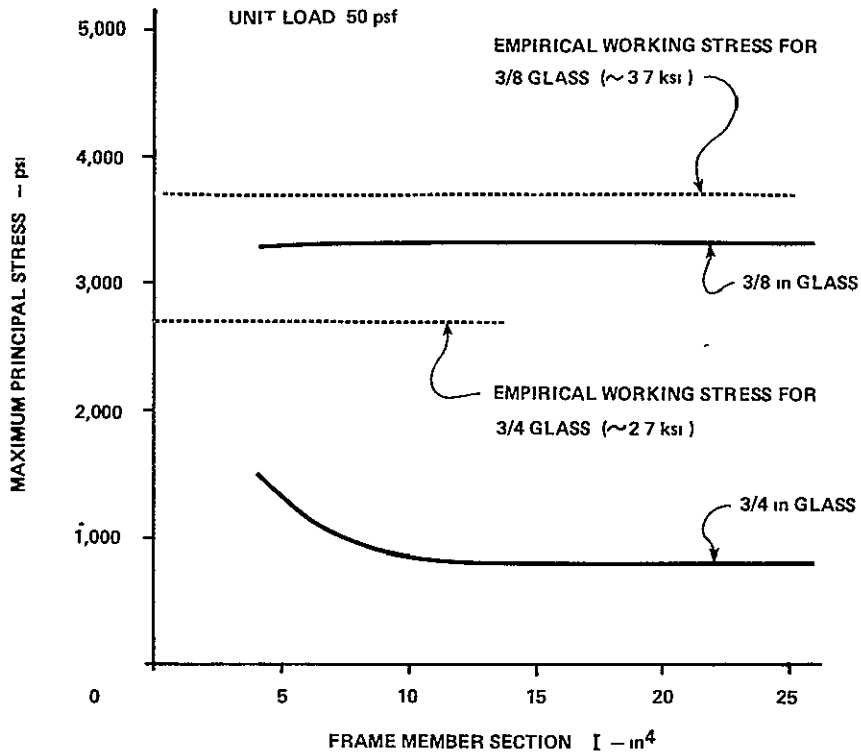


Figure 4–13 MAXIMUM GLASS BENDING STRESS IN TYPE 'B' PANEL

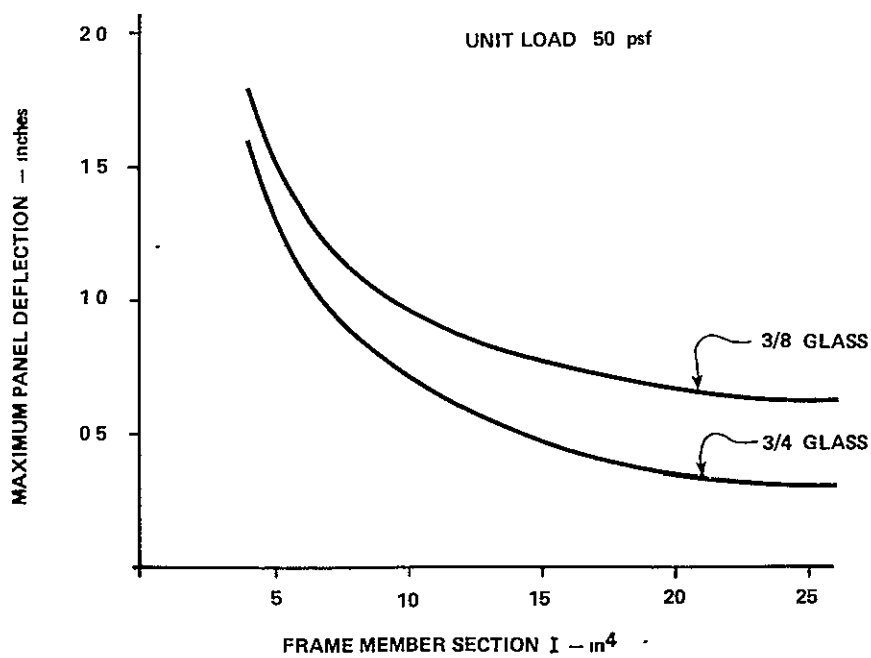


Figure 4–14 MAXIMUM GLASS DEFLECTION IN TYPE 'B' PANEL

The stress results show that there are minimum sizes of steel frame members below which the maximum glass stress increases above the allowable. This effect depends on the loading, the frame configuration and the glass thickness. Of the two frames considered in this parametric study, the type 'A' configuration is preferred over type 'B' because of better structural performance and a slightly lower cost. Stresses in the 3/8 inch thick glass remain fairly constant for the cases considered. When member sections are sized smaller and the glass is thicker, the glass stress becomes sensitive to edge support conditions. The bending stresses in the steel frame members depend also on the panel configurations and are shown in Figure 4-15. These frame members reach allowable stresses for sections with moments of inertia near 5 in.^{4} to 10 in.^{4}. This is less than the transition region for glass stresses. Whereas steel stresses continue to decrease for increased member sizes, the glass stresses are independent of this and remain constant for the thicknesses considered.

In conclusion, it has been shown that the interaction of the steel frame and glass modules depends on the total panel configuration. The glass stresses have some dependency on the stiffness of the steel frame members. Too light a frame will cause steel and glass to exceed allowable stresses under the design loads. There is a minimum size of frame member for any panel above which increases in steel member sizes have little influence over glass stresses. This size represents the lower

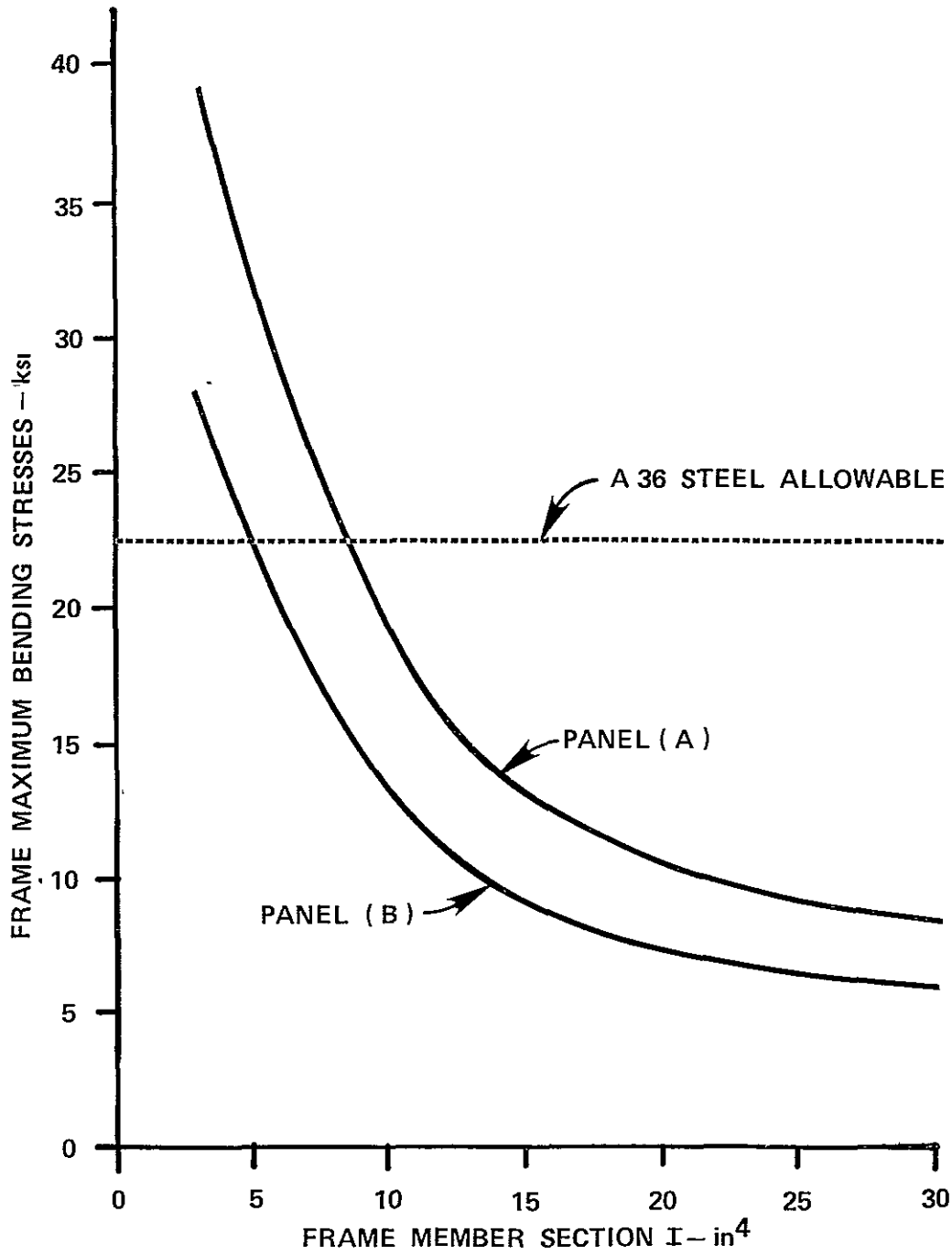


Figure 4 - 15 MAXIMUM BENDING STRESSES IN PANEL FRAMES

limit of providing an effective simple support to the glass. The critical member sizes must be determined in future studies for the specific prototype panel configurations using a suitable structural analysis procedure that recognizes the nonlinear response of the glass modules.

4.3.4 Panel Impact Analysis

It can be anticipated that handling of panel assemblies will require holding the panel by an edge, with the unit hanging in the vertical plane, as well as shipping the units standing on edge. In this study an analysis was done to determine the response of the panel system to in-plane forces. The response to a suddenly applied force can be represented by applying twice the force applied statically. This was considered to be the probable magnitude of forces experienced by shipping and handling these units. However, dropping a panel on its edge will give much higher g levels. Such a condition can be extrapolated from a 2g analysis. Thus, a 2g force field was used as the basis.

For this study it was assumed that the glass edges would be enclosed in a resilient protective sheath before clamping to a steel frame member. This resilient layer was assumed to allow small movements in the plane of the panel (such as those caused by temperature differentials) as well as allowing small rotations about the axis of the edge but preventing movement perpendicular to the edges. This detail makes a rigorous in-plane analysis

geometrically nonlinear and suggests an iterative analytical solution in order to eliminate tension contacts between the glass and the steel members. A conservative method to avoid this complex procedure was employed instead. This analysis was done separately for (a) a glass 4x8 foot module with in-plane body forces and for (b) a complete Type A steel frame also subjected to in-plane forces.

Contact between the glass and the steel frame was assumed to be at the bottom corners only of each module. Consequently, the steel frame was analyzed for 2x self-weight, plus 2x glass weight applied at the frame corners. The glass 4x8 foot module was analyzed for 2x self-weight, supported only at bottom corners, and 3/4 inch thick glass (twice the weight of the preliminary estimate derived in Section 4.3.2). This analysis was done using membrane finite elements and the Bechtel computer program CE800-BSAP.

The maximum stress derived for the steel frame is 394 psi and is not significant compared with the steel allowable of 22 ksi. The maximum shear in the glass is computed as 100 psi while the maximum principal tension is about 70 psi. These stresses are not significant compared with typical glass working stresses. The analyses show also that the in-plane deflections of the bottom edge of the glass plate are much less than the maximum deflections of frame members. This supports the assumption that glass modules would be mainly supported at their corners.

These results show that handling stresses caused by 2g decelerations of a Type A panel unit with 4x8 foot, 3/4 inch thick glass modules have small magnitudes.

4.3.5 Array Support Structure

As discussed, the array support concept chosen for consideration was for a simple structure carrying the preassembled panels. This approach is intended to give some order of magnitude for the sizes of the structural members required to carry the design forces.

The support structure is visualized as a series of simple column frames spaced along the array and carrying two longitudinal beams which support top and bottom edges of the panel assemblies. The column frames are shop fabricated and delivered to the site for erection on suitable foundations. The longitudinal beams are site welded or bolted in place to complete the array support structure. This general arrangement is shown in Figure 4-15.

A parametric study was performed to determine the beam and column frame sizes needed for various beam spans (or column frame spacings). For this work a unit loading of 50 psf was used on the glass modules. In comparison with the critical loads listed in Table 4-3, this figure represents a reasonable upper bound loading. In addition a cleaning gantry was assumed to run along the beams providing a 1000 lb reaction to each beam. This was

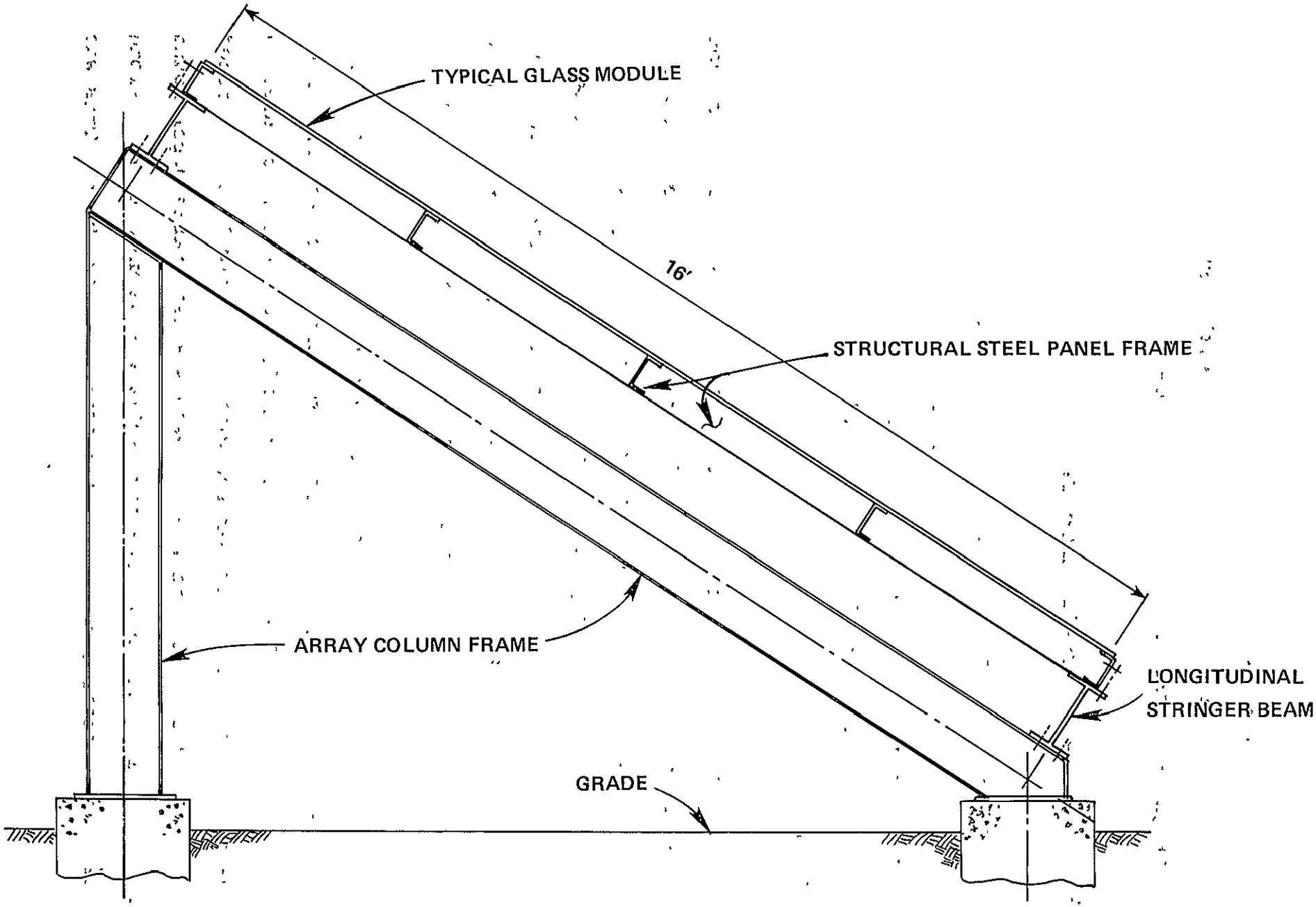


Figure 4 - 16 CONCEPTUAL ARRAY SUPPORT FRAMES

assumed to include an impact allowance. Original calculations included a washing gantry reaction of 2000 lb per beam. This was later reduced to 1000 lb on the advice of a washing system manufacturer. Support beams were assumed to be continuous with moment connections at the column frames. The analyses for varying spans gave beam moments and columns loads. Beam sizes were selected for these cases and then an approximate frame analysis was performed in order to size the column frame members. These frames resist both horizontal and vertical force components and so axial and moment forces are induced in the frame members. The preliminary member sizes are listed in Table 4-5 for the array system with a front height of 2 feet above the ground.

Table 4-5

ARRAY SUPPORT SYSTEM MEMBER SIZES

Stringer Beam Spans	Beam Sections	Column Frames	Net Uplift per Span
16 ft	W6 x 20	M5 x 18.9	10 kips
24 ft	W8 x 31	M6 x 20	14 kips
32 ft	W14 x 48	W6 x 25	18 kips

These preliminary member sizes give an estimate for system dead loads and allow the wind uplift to be checked. Since the wind provides an upward suction over the sloping panels, it may be necessary to provide extra resistance in the system for net upward forces. The calculations show that there is a net upward force due to wind which may be resisted by foundation caissons or

by sizing concrete footings to suit weight requirements. Consideration of foundations is outside the scope of this work, but the net uplift forces per span that should be considered are shown in Table 4-5.

The frame member sizes were checked for the cases when the front of the array system is (a) lowered to ground level as shown in Figure 4-16, and (b) raised to a 6 foot height while maintaining the array inclined angle. The ground level arrangement eliminates much of the moment action in the members, and so sizes can be reduced to 4 and 2 inch structural sections, for example. Raising the front to 6 feet causes an increase in all member forces, and member sizes must increase. These cases were checked only for the assumed maximum 32 feet span between column frames. As a measure of the structural effect of height changes, the approximate weights of steel are listed in Table 4-6 for each typical column frame. Beam sizes are not affected by the changes in height considered in this study. Theoretical considerations would change the wind velocity with height changes, but this is impractical below 30 foot height where the design wind is specified to be uniform.

Table 4-6

INFLUENCE OF HEIGHT ON COLUMN FRAMES

Front Column Height	Column Frame Weights
Zero	200 lbs
2 ft	800 lbs
6 ft	1800 lbs

Temperature effects should be recognized in the array support structure by allowing for expansion at approximately 250 foot intervals along the array. A conventional method at those locations is to have separate, adjacent column frames spaced to allow for temperature closure from winter to summer. The entire array structure including panels and beams are spaced apart at these points. For a seasonal design temperature range of 152°F, the end movement of a 250 foot steel structure, assumed symmetrical about its center, will be 0.1235 foot or 1-1/2 inch. Expansion joints are needed to provide a 3 inch gap at 250 foot intervals along the array.

As discussed in Section 6.2.1, the preassembled panels may be lifted on edge into position, set against a stop on the lower array beam, then clamped down with anchor bolts at top and bottom edges. Two bolts are used on the top edge of each panel frame near the 16 foot edges; two correspondingly located bolts are used along the lower edge. Preliminary analysis led to the selection of anchor bolts inserted into predrilled holes in the

panel frames and stringer beams to provide the needed restraint in an economical manner compatible with ease of installation. Conceptual details for this are given in Figures 4-17 and 4-18.

Seismic considerations at some sites may require additional restraints for the panels against horizontal forces.

4.4 SENSITIVITY TO CRITERIA CHANGES

Changes in the acceptance criteria for the glass modules will alter the selections of glass thicknesses. The empirical allowable stresses were derived in this work from recommendations for window selections (Ref. 5). Those curves are related to a breakage risk of 8 units per 1000 when design loads are applied. This corresponds to a factor of safety of 2.5 to nominal ultimate stress. If a breakage risk of 1 unit per 1000 is preferred, then the safety factor becomes 5.0. The effect of this would be to change the thickness of a 4x8 foot module from 3/8 inch to 1/2 inch, which is a 33% increase in glass weight.

High strength steels may be used to save weight; however, it has been shown that steel stiffness, a function of modulus E, is actually the key design parameter for module frames, and has a constant value for the different types of steel. In any event, weight saving is not important when uplift forces due to wind may require greater dead weight.

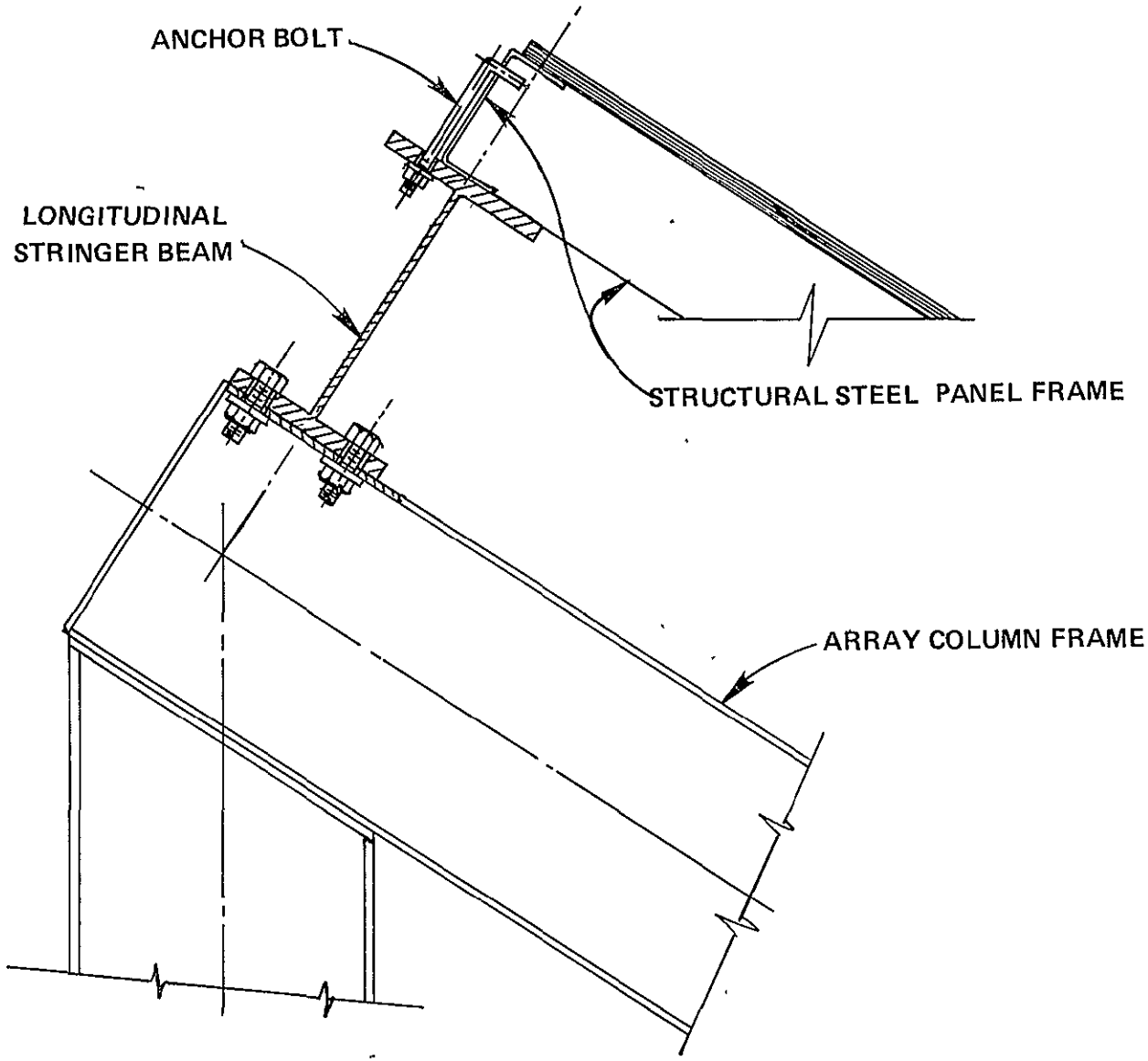


Figure 4-17 DETAIL FOR UPPER CONNECTION CONCEPT

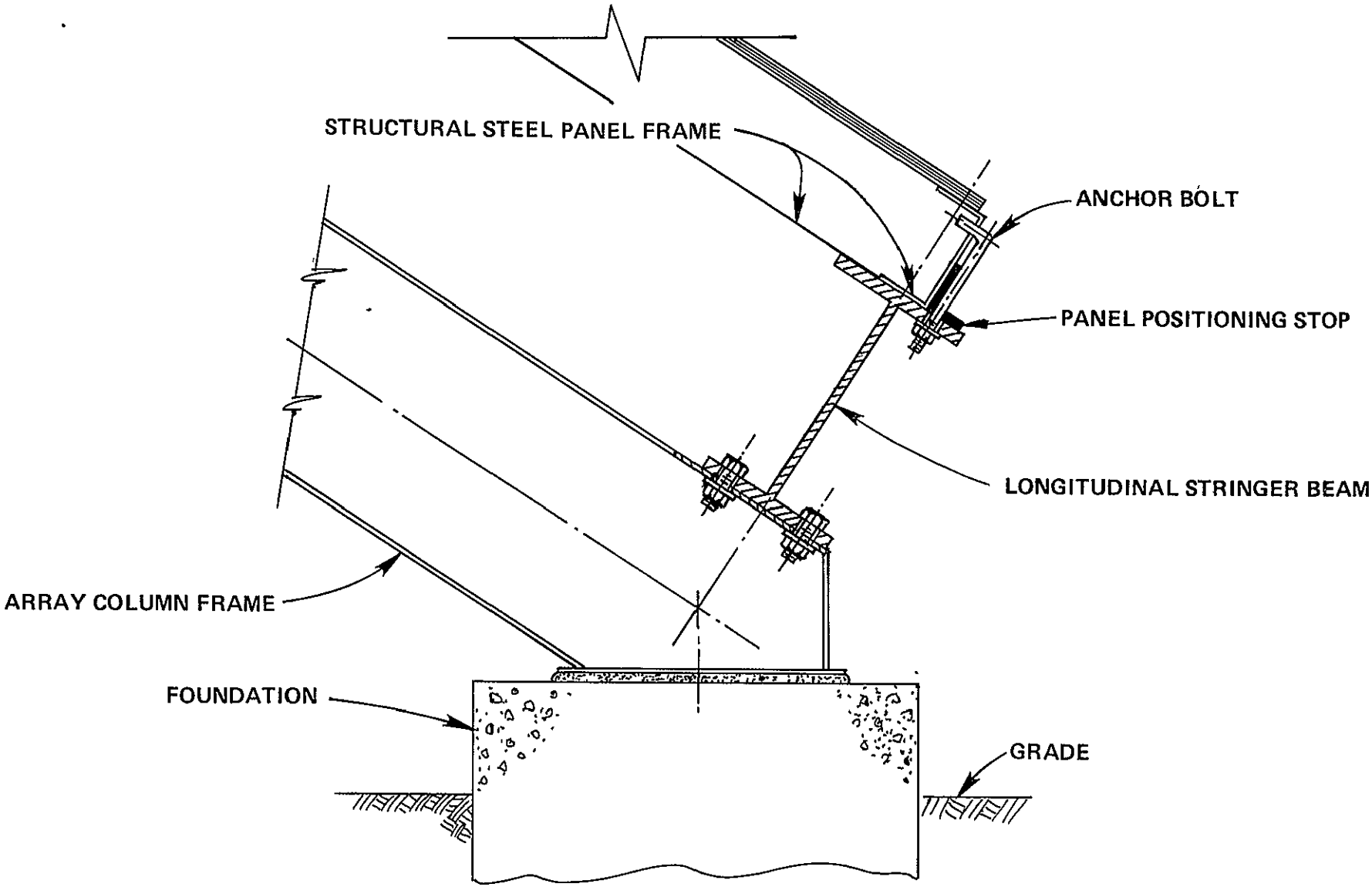


Figure 4-18 DETAIL FOR LOWER CONNECTION CONCEPT

The loading criteria are sensitive to the site environmental conditions. Three key load parameters that are site dependent are the snow load, the wind speed, and the seismic zone coefficient. A study was conducted to survey the major geographical regions of the contiguous U.S. to estimate the maximum critical loading. It is not realistic to find the maximum values for each parameter from different regions and then use them together to find a critical load. Instead a maximum was found for each parameter in turn. This pointed to one or two specific regions of the country. Then a region was selected which tended to maximize an associated parameter. For example, high wind values are found in Florida as well as along the Carolina coastline. However, the snow values for the Carolina coast are greater than for Florida and so the Carolina coast is selected for highest winds.

In this way, a list of maxima is devised and is given in Table 4-7. Next the load combinations are reviewed for each site, using the guideline in Table 4-1, so that the site critical load is obtained. Finally the maximum loading from these selections gives a possible upper bound critical load for any site in the country. For comparison the Phoenix area parameters are added to Table 4-7.

Table 4-7

VARIATIONS IN LOADING PARAMETERS

Maximized Loading	Load Criteria Snow psf	Wind mph	Seismic Zone	Geographical Region
Snow	70*	100	2	Upper New England
Wind	10	120*	1	Carolina Coast
Seismic	10	85	4*	California Coast
-	5	80	2	Phoenix, Arizona (baseline)

*Maximum values

The critical loads are next found for each region using the parameters listed in Table 4-7 and assuming 3/4 inch glass modules. For all cases the seismic loading was relatively small and was never a governing item. The results are as follows:

Maximized Load Parameter	Critical Loading
Snow	102 psf
Wind	86 psf
Seismic	49 psf

Consequently the maximum loading that may have to be considered for a photovoltaic plant in the contiguous U.S. is about 102 psf over the panels. This is more than twice the unit loading of 50 psf used in this study for the Phoenix area.

Calculations show that the glass modules must be changed to 3x6 foot for 3/8 inch glass, or increase the thickness of the 4x8 foot module to 5/8 inch from 3/8 inch. An analysis like that described in preceding sections of this report is necessary to establish the stiffness of the frame members. Extrapolating the results reported in Figures 4-11 and 4-12 confirms that the 3/8 inch glass in a 4x8 foot module remains overstressed for this extreme load case regardless of changes in frame member stiffness properties, and a thickness change is needed.

Further checking of the structural changes was done by reviewing the 32 foot span case. The increased array support beam moments can be handled without a change in section by assuming that the beams are laterally braced at least at 16 foot intervals by the attached frames. It becomes necessary to change from W6x25 to W8x35 sections, representing a 40% increase in weight of these units.

It is therefore demonstrated that a photovoltaic array structure for any part of the country can be developed from the parametric studies reported here. This may be done by choosing appropriate steel sections. Despite the potential large changes in loading criteria, the steel sections do not vary greatly in size.

The foregoing analyses and results would not change for larger plants, e.g., 1000 MW, since such plants would simply be comprised of additional array groups. Similarly, for a small

plant, e.g., 10 MW, it is anticipated that there would be little change and the plant could be comprised of a single array group of the arrays described herein.

Section 5

ELECTRICAL CONSIDERATIONS

Electrical aspects of the modules and the interface between the modules and the arrays are presented in this section.

This area cannot be properly evaluated without considering portions of the design features of the entire plant, since many of these plant features tend to govern selection of the modules' electrical characteristics. Analysis of the module and interface requirements involved evaluation of components associated with the arrays in order to determine design constraints imposed on the modules by these components and to determine their characteristics as a function of module size and other design parameters under consideration. Following this, the characteristics of the electrical components, their interaction and cost are evaluated in conjunction with the structural considerations discussed in Section 4, to arrive at module and interface electrical characteristics which would minimize total plant life-cycle costs.

5.1 ELECTRICAL COMPONENTS

In addition to the modules, connector and converter designs exert a strong influence on the module/array interface.

5.1.1 Modules

Modules are discussed briefly to present the electrical characteristics used as a basis for design considerations.

As defined herein, modules are the smallest electrical unit with which the plant system designer will interface. A module consists of an encapsulated, self-supporting assembly of silicon solar cells. Modules, in turn, may be factory assembled into panels to form a unit which is more economical to ship and install. Internal series and parallel wiring connects the cells and terminates in two wires (positive and negative) emerging from the module. For purposes of this study, the voltage and current behavior of the modules is assumed to be given by a linear scaling of the characteristics of a single solar cell.

Cell Characteristics. The following assumptions regarding solar cell voltage and current characteristics are used in this study:

- The open circuit voltage is 0.6 volt/cell at 28°C (82°F) cell temperature.
- The nominal operating temperature is 45°C (113°F).
- The open circuit voltage decreases by 0.0022 volt per cell per °C. Thus at 45°C, the module's open circuit circuit voltage is 0.563 volt per cell.
- The maximum power point voltage is 0.1 volt per cell less than the open circuit voltage. Thus at 45°C the module's operating voltage is 0.463 volt per cell.
- Short circuit current is 110% of the current at the maximum power point.

Module Characteristics. This study is based on attaining cell efficiency and packing density goals which result in a peak power output of 10 watts per square foot of module surface. It is assumed that this maximum power output occurs at an insolation of 100 mW/cm² and a cell temperature of 45°C.

The baseline design is for a 200 MW central station power plant. Thus, with the above power density, 20 million square feet of module surface is needed. Figure 5-1 shows the number of modules required versus module size. Since each module has one inter-

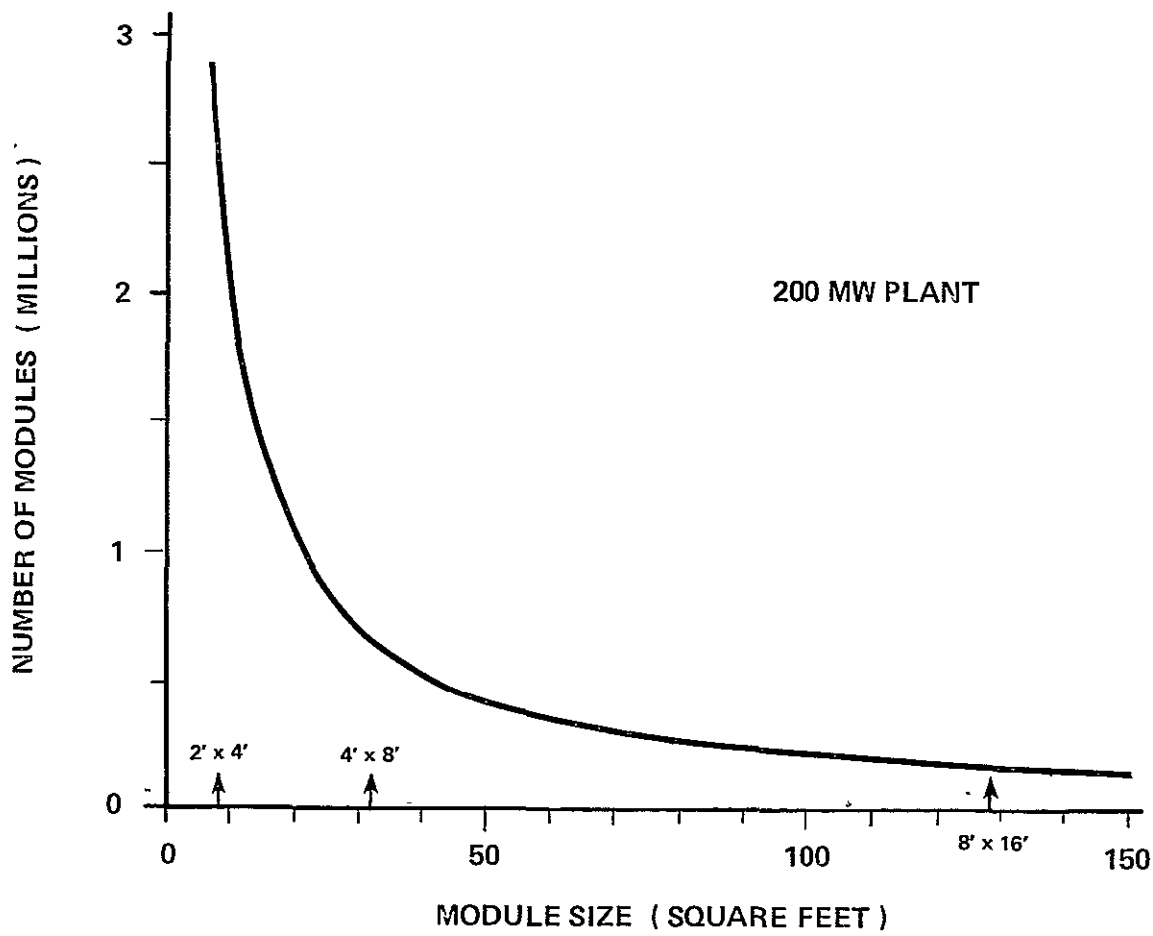


Figure 5 - 1 MODULE QUANTITY VERSUS SIZE

module electrical connector pair associated with it, the figure also shows the number of connector pairs required in a 200 MW plant as a function of module size. Additionally, the figure illustrates the number of module installation operations to be performed. Figure 5-1 is presented on a linear scale to emphasize these latter two points, since they contribute strongly in selecting an optimum module size. The arrows on Figure 5-1 indicate the three module sizes (2x4 foot, 4x8 foot, and 8x16 foot) evaluated in detail in this study.

Series and parallel interconnections of the cells within a module allow a wide range of voltage and current combinations. For economic reasons discussed in subsequent sections of this report, low voltage, high current modules are preferred. Figure 5-2 shows the maximum (i.e., short circuit) module current as a function of module size with open circuit voltage as a parameter.

As mentioned, module characteristics are linearly scaled from cell characteristics. Thus, the module maximum power voltage at the 45°C operating temperature is obtained by multiplying the open circuit voltage at 28°C by 0.771 (0.463/0.6); the corresponding maximum power current is obtained by dividing the short circuit current by 1.1. These basic module characteristics are used in evaluating other system components and designs.

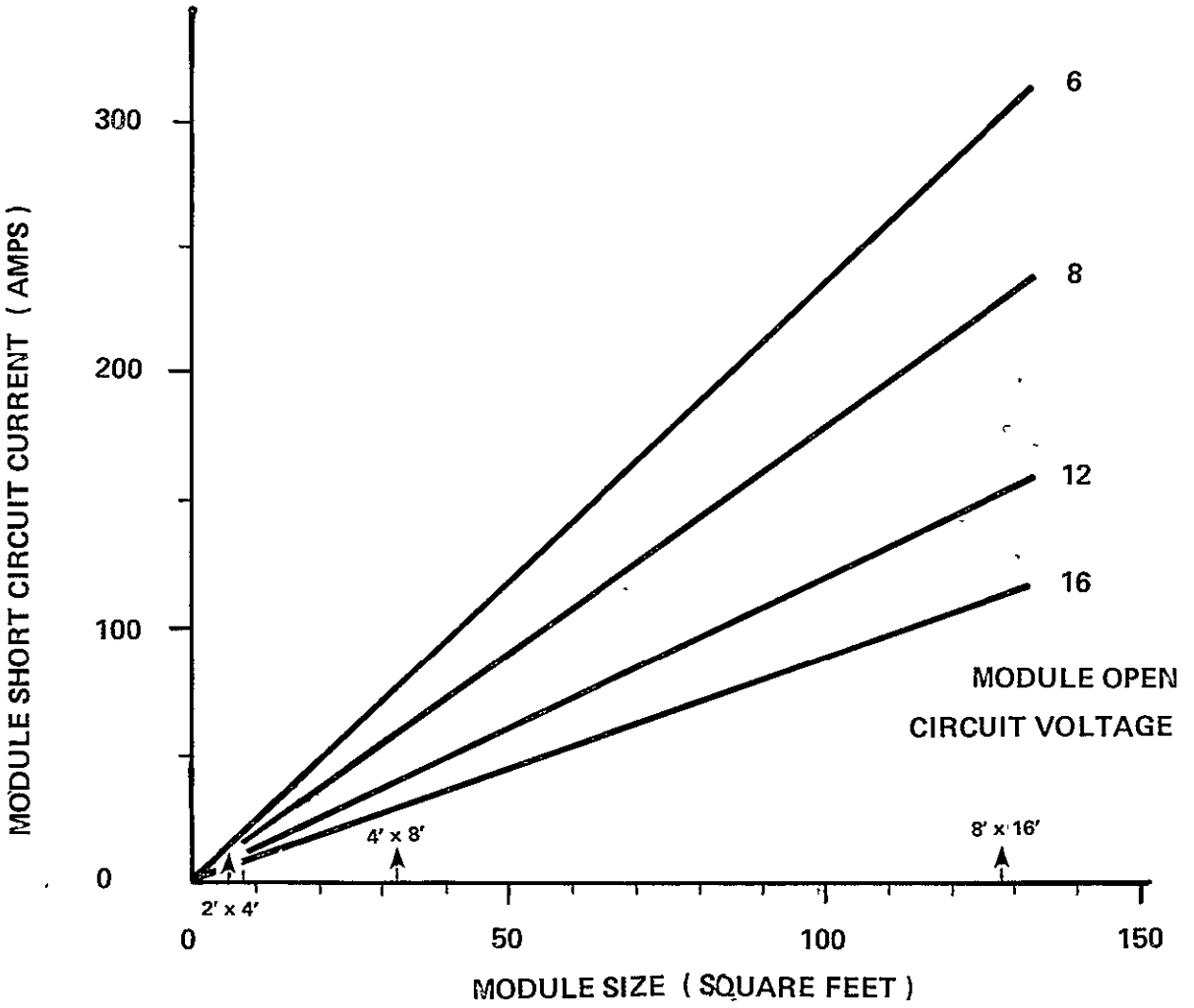


Figure 5 - 2 MODULE CURRENT VERSUS SIZE

5.1.2 Intermodule Connectors

Assembly of individual modules (or panels) into arrays requires that the modules be electrically connected to each other in appropriate series/parallel configurations in order to provide the desired array voltage and power.

General Requirements. Several overall general requirements should be met by the intermodule connections.

Intermodule connections must be capable of continuous operation at normal system currents and voltages. Also, they must not be damaged by transient overvoltages or by operation at maximum short circuit current for short periods. Voltage ratings are dependent upon the selected system operating voltage and the method of system grounding. It is expected that maximum system operating voltages will be in a 1000 to 4000 volt range, with transient voltages of 1000 to 10,000 volts (see Sections 5.1.3 and 5.3). In all cases, connector insulation dielectric breakdown rating should be equal to or greater than the solar cell module insulation ratings. Current ratings are between 10 and 300 amps for the system designs considered in this study.

In view of the number of connections to be made, the connectors should be inexpensive. For reasons of total cost, the connection should require a minimum amount of field labor during initial installation of the modules. Automated assembly methods at the factory should be exploited wherever possible in order to reduce field labor requirements, and hence total installed cost. Further, from an array maintenance viewpoint, it is desirable to have connections that can be easily disconnected. Also, it is anticipated that the modules will be tested at the factory. This increases the need to have a connector that is easily connected and disconnected.

The connectors must be capable of surviving exposure to rain, snow, ice and windborne dirt. Also, the insulation material must

be capable of withstanding long-term exposure to ultraviolet radiation and reactive atmospheric constituents, such as ozone, without significant deterioration of physical or electrical properties.

Because of the large quantity of inter-module connections required (>100,000), frequent connector failures would significantly reduce the plant energy output and create a maintenance problem. In addition to complete failures, slow contact deterioration over a period of years seriously reduces plant output by increasing contact resistance and I^2R losses. The connectors should be designed to minimize such problems.

Connection Types. Several types of connection schemes were evaluated in this study, including the following:

- In-line butt splice
- Wire wrap
- Terminal block
- Two piece, quick-disconnect type connector

The in-line butt splice connection consists of a hollow, cylindrical metal lug. The two wires to be joined are inserted into the lug. One wire is inserted at each end and, with the aid of a mechanical tool, the lug is crimped into the wire, forming a permanent connection. The joint is then insulated by the application of shrinkable tubing, tape or other such means. This

method produces an acceptable connection from an electrical standpoint, but the field labor requirements are relatively high. For example, Bechtel Power Corporation manhour estimates for this type of termination (on 600 volt wire and exclusive of any applied insulation) range from 0.25 manhour for a #14 AWG (10 amp) connection to 0.57 manhour for a #4 AWG (100 amp) connection. These estimates reflect actual field experience. Using a fully burdened labor cost of $25.00/manhour yields costs per connection of $6.25 and $14.25, respectively, for the #14 and #4 sizes. System voltages will be greater than 600 volts and require thicker insulation to insulate the splice and a cover to protect it from the environment. Because of these cost factors and the permanent nature of the connection, the in-line butt splice was eliminated as an intermodule connection method.

Wire wrap connections are made by a machine tool tightly wrapping a wire around a terminal post. They are widely used in the telephone, computer, and other electronics industries. This type of connection has been shown to be a fast and reliable method for making large numbers of connections in the electronics industry. However, its application has been generally limited to low power applications. The largest wire size in use is about a #18 AWG. In addition, the feed-through terminal posts required for intermodule connections would require full dc system voltage rating, and the completed connection would still require insulation in the form of a rubber boot, tape, or other means. Both of these requirements tend to increase the cost and

complexity of the connection. Further, this type of connection is not easily disconnected and reconnected. The lack of experience for wire wrap connections with the ampere ratings required and reconnection difficulty led to the exclusion of wire wrap connections from further consideration at this time.

The configuration of the screw-type of terminal block connection is similar to that of the wire wrap connection, except that the mechanical connection of the wire to the feed-through bushing (terminal block) is accomplished via a screw, mounted on the bushing. Although connections of this type can be made for the ampere ratings required, bushing costs and insulation requirements, along with the level of field labor required to accomplish the connection, make this method less preferable.

Quick disconnect type connectors consist of two connector bodies, one of which contains a male electrical contact and one a female contact. The connectors are assembled and attached to the module at the factory during fabrication. Connector bodies can be either bulkhead mounted directly on the module framework, or installed on wire pig-tail leads. Complete factory assembly of the connector greatly reduces the field labor required to make the connection. Once the modules have been installed on the array structure, the male and female connector bodies are simply "plugged-in." This requires no tools and minimal time. The connection is also amenable to rapid disconnection and subsequent

reconnection. Also, it is readily available in weatherproof versions.

Of the types of connectors considered, the quick-disconnect appears to be best suited for the present application.

Quick-disconnect Connectors. Many types of quick-disconnect connectors are available from a number of manufacturers, such as Amphenol, Cannon, and others. One of these types, the ITT Cannon Sure-Seal Connector, was investigated in detail. Originally developed for the automotive industry, larger versions of the Sure-Seal connector show promise of providing a low-cost, environmentally protected intermodule connector capable of operating under the required current and voltage conditions.

The Sure-Seal was one of the connectors tested by JPL in its program to assess the applicability of commercially available connectors in solar array systems (Ref. 13). Electrical, mechanical, and environmental characteristics were investigated, with the Sure-Seal yielding generally favorable results. Tested specimens successfully withstood a 1 minute, 1500 V ac dielectric withstand test while exhibiting high voltage breakdown characteristics in the range of 5000 volts. Environmental performance was generally good, except that the connector bodies (composed of a nitrile rubber and PVC compound) were attacked harshly in ozone and ultraviolet environments. A non-production version of the connector, which utilizes an Ethylene Propylene

Diene Monomer (EPDM) body, was also tested and exhibited good performance in ozone and ultraviolet environments.

The present line of Sure-Seal connectors has insufficient current carrying capacity for all practical panel sizes and voltages as indicated by the range of required connector current ratings shown in Figure 5-2. ITT Cannon was contacted to determine the feasibility and cost impact of scaling up the Sure-Seal design to meet the intermodule connector requirements. Figure 5-3 presents Cannon's proposed design for a 100 ampere, single contact Sure-Seal type connector.

Budgetary cost estimates for this type of connector were obtained from Cannon. Table 5-1 summarizes these costs in terms of material cost, purchase quantity, and cost to assemble (1977 dollars). In addition, there would be a one-time, partial tooling charge of $18,500.

Table 5-1

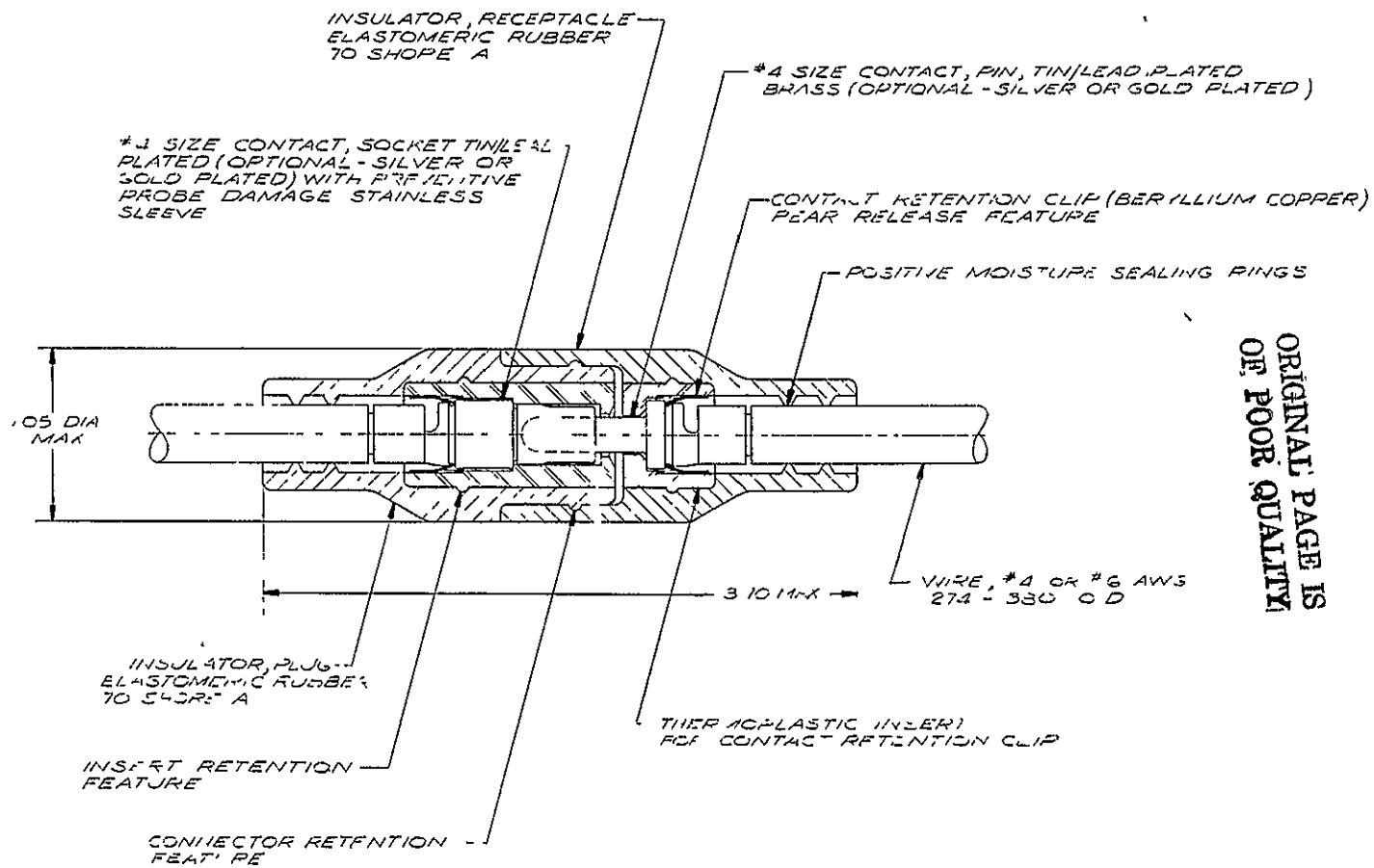
CONNECTOR COST

Connector Rating (Amperes)	Connector Cost ($/mated pair)	Assembly Cost ($/mated pair)	Purchase Quantity*
10	0.29	0.17	1×10^6
25	1.88	0.25	5×10^5
100	3.26	0.33	8×10^4

* The number of connector pairs required is given by the curve in Figure 5-1

THIS IS ISSUED IN STRICT CONFIDENCE ON CONDITION THAT IT IS NOT USED AS A BASIS FOR MANUFACTURE OR SALE, AND THAT IT IS NOT COPIED, REPRINTED OR DISCLOSED TO A THIRD PARTY EITHER WHOLLY OR IN PART WITHOUT THE PRIOR WRITTEN CONSENT OF ITT CANNON ELECTRIC.

REVISIONS				
ZONE	LTR	DESCRIPTION	DATE	APPROVED



REFERENCE	INTENDED USE	PART NUMBER
	PROPOSAL	

DIMENSIONS IN INCHES TOLERANCES FOR DECIMALS AND ANGLES AS SHOWN DO NOT SCALE

MATERIAL

FINISH

TREATMENT

DRAWN	Z CHYLINSKI	3-18 77
CHECKED		
APPROVED		3-18 77
APPROVED		
APPROVED		

ITT CANNON ELECTRIC
666 EAST DYER ROAD
SANTA ANA, CALIFORNIA 92702
A Division of International Telephone and Telegraph Corporation

100 AMP CONNECTOR
SS-1

SIZE	CODE IDENT NO	
C	71468	XC-1138
SCALE 2:1	WT	SHEET

CEC255C HQ (REV 6-66)

Figure 5-3 INTERMODULE ELECTRICAL CONNECTOR

ORIGINAL PAGE IS OF POOR QUALITY

Connector assembly is a factory operation consisting of semi-automated crimping of the connector contact to a precut wire and manual insertion of the contact into the connector body. Possible full automation of the assembly process could lead to cost reductions although, as can be seen in Table 5-1, assembly is not the major cost for the large connector. Connector assembly can be accomplished by the module manufacturer, or a sub-contractor, prior to the installation of the wire on the module.

Cannon indicated that, for the range of system voltages being considered, appropriate connector voltage ratings can be accomplished by varying the thickness of the rubber connector body. This would be done during the initial design phase and would have relatively little impact on overall connector cost, because the quantity of material involved represents a small portion of the total cost.

The data from Table 5-1 are plotted in Figure 5-4, which shows connector cost versus connector rating. The cost of the wire between the module and connector, and the cost of attaching the wire to the cells within the module is not included, since these costs would be present regardless of the type of connector used and would logically be included in the module cost. Similarly, the costs shown do not include the cost to connect the modules after they have been installed on the array framework. The simple operation of pushing the two connector halves together can

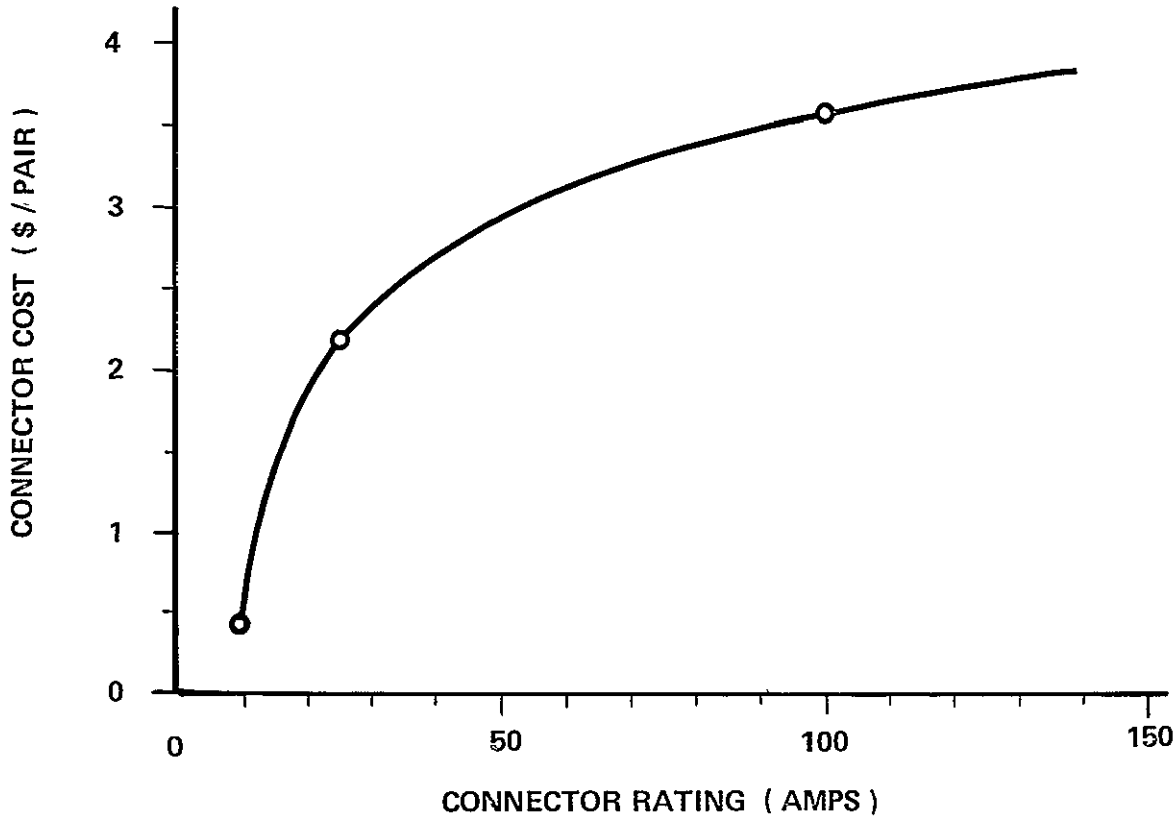


Figure 5 - 4 CONNECTOR COST VERSUS RATING

be accomplished during the mechanical installation of the modules for an added cost that is not significant within the accuracy of the present cost estimate.

A more detailed analysis of connector design and manufacturing costs would likely result in a cost versus size curve that consists of discrete line segments. In practice, designs would be developed for a range of currents (e.g., 0-10 A, 5-30 A, etc.), with an approximately level cost in each range. It is felt that the curve in Figure 5-4 is a reasonable presentation of available data. The leveling-off of connector cost at higher ampere ratings shown by Figure 5-4 generally agrees with Cannon's

assessment of cost variation with size. Also, it is obvious that costs do not continue to decrease to zero or go negative for connector sizes below 8 amperes as might be indicated by extension of the curve in Figure 5-4.

Connector costs from Figure 5-4 are combined with the number of connectors required (Figure 5-1) and module current (Figure 5-2) to calculate connector cost as a function of module size. Calculation results are presented by Figure 5-5. The connector costs in Figure 5-5 are normalized to dollars per watt. The length of the parametric module-open-circuit-voltage curves are such as to encompass connector ratings from approximately 10 to 150 amperes.

As can be seen in Figure 5-5, connector costs generally favor selection of large size modules. The higher costs for large connectors is outweighed by the decreasing number of connectors required. Connector costs are not very sensitive to module voltage for the larger module sizes. Selection of a low module voltage (e.g., 6 volts - open circuit) for a large module size will necessitate development of a connector larger than the 100 ampere version shown in Figure 5-3. However, it is felt that module currents should be limited to about 100 amperes, so that attaching the wire to the intercell wiring within a module will not become overly difficult and expensive.

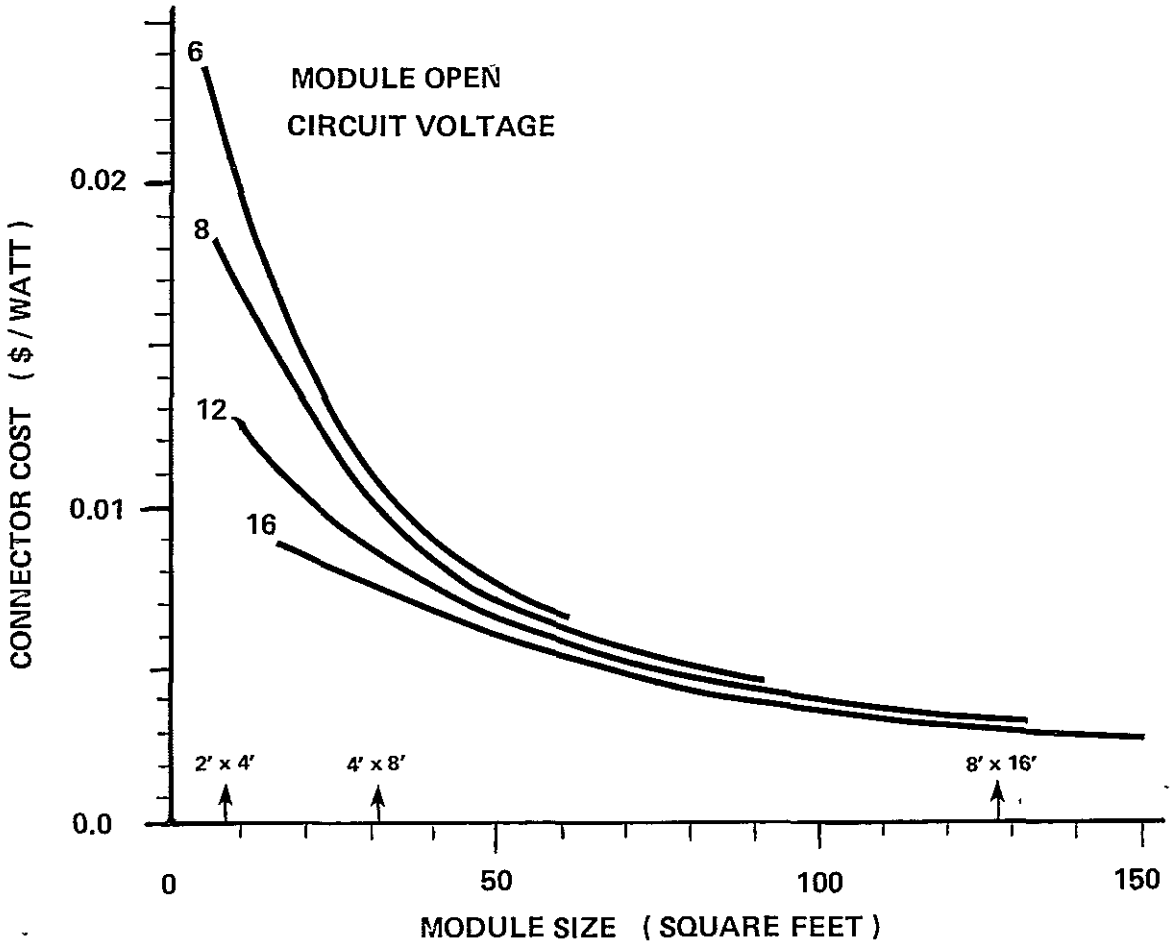


Figure 5-5 CONNECTOR COST VERSUS MODULE SIZE

5.1.3 Converters

Converter equipment must be included in a photovoltaic power system to interface the dc generated by the solar arrays with an ac utility network. While converters per se are not a part of this study, they must be considered, at least to the extent that their parameters affect module design. Thus, converters are discussed briefly herein to support the logic used in setting

module and array system parameters. In particular, the dc voltage rating of the converter determines the selection of the array voltage (or vice versa). Also, the converter's power and current ratings affect the way in which the array outputs are connected in parallel. For the systems considered herein, the parallel output of a group of arrays feeds each of the converter units in the plant.

Converter equipment of the type needed for a photovoltaic central station is currently being developed as a part of the programs to apply fuel cells and battery energy storage in the electric utility industry. Several different converter designs are being pursued by various manufacturers. However, sufficient commonality exists to allow converter system parameters to be postulated for purposes of this study.

Power Level. For the power levels associated with a photovoltaic central station, the converter equipment would be comprised of several smaller converter units whose outputs are paralleled on the ac side. It is expected that each of these units would have a rating in the 2 to 10 MW range. Arrays are paralleled into groups to supply each converter unit with its rated power.

The fact that a plant's converter system will very likely be comprised of small, separable units can be used to advantage. With multiple converter units dispersed throughout the plant, the relatively low voltage, high current (dc) array output is

transported only a short distance before being transformed into a high voltage, low current (ac) waveform. Thus, less copper is required to collect a given amount of power at a fixed I^2R loss. A second advantage is that current levels in the dc bus collecting the array outputs are not built up to a level where fusing and switching become difficult.

Current Level. The maximum dc current input to a converter unit is, to a large extent, governed by the ratings of the available SCRs used in the converter bridge. Most manufacturers tend to avoid paralleling of SCRs in individual bridge legs, preferring rather to parallel bridges within the converter unit in order to increase current levels. This approach also reduces the amount of harmonic filtering required on the ac output. Typically, each converter unit contains 2 or 3 bridges; some may contain 5 (depending on the manufacturer).

Differences in intended application, design, type of SCR required, and a manufacturer's design safety factor philosophy result in various current ratings for bridges and converters. However, evaluation of available data indicates that selecting 4000 amperes as the maximum dc input current to each converter unit is reasonable for purposes of this study.

Voltage Level. As mentioned, selecting the voltage level for the array-converter dc bus system is strongly influenced by the

characteristics of the converter. The driving force in this area is the converter cost as a function of dc voltage.

This cost behavior is shown in Figure 5-6. The curves are based on data for different converter designs from several manufacturers. The data are normalized to give a relative cost of unity at 2500 volts (curves displaced slightly for visual clarity). Three budgetary price estimates averaged $56/kW (1976 dollars) for a converter similar to the type needed in this application. The estimates were for mature production versions of a 20 MW, 2500 volt dc converter to be used in a lead-acid energy storage plant. Shipping and installation costs must be added to the above purchase price.

As can be seen from the figure, dc system voltages below 500 volts should be avoided. Costs continue to decrease rapidly up to about 1200 volts. Above this point costs decrease much more slowly as the voltage increases, so that the optimum converter voltage rating (above about 1200 volts) will be determined by interarray cabling costs, I^2R losses, and the economics of array and module sizing. Above 1200 volts, converter costs vary approximately as voltage to the -0.2 power.

<u>Other Converter Factors</u>. Converter equipment can introduce voltage transients onto the array dc bus. Such transients result from transients on the ac side of the converter being passed through the equipment and from fault interruption. The magnitude

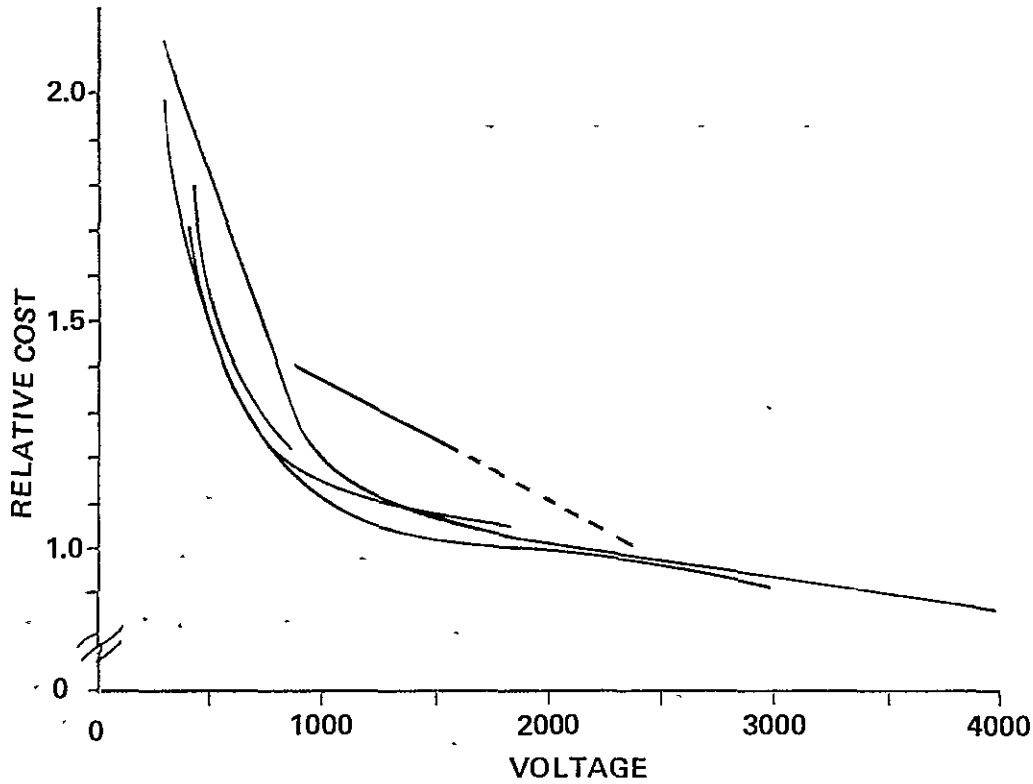


Figure 5 - 6 RELATIVE CONVERTER COST VERSUS VOLTAGE

or existence of such transients at the array terminals depends on several factors the detailed analysis of which is beyond the scope of the current study. Included among these factors are the type of converter, the design of its dc filter, existence of a battery across the dc bus, and the impedances of the array, bus, and any other equipment between the converter and array terminals. Generally, self-commutated type inverters will have much lower voltage transient levels than line-commutated types. A nearby lightning stroke on the ac side of a line-commutated converter may produce a 3 to 4 p.u. (per unit) transient on the dc side, despite a lightning arrestor. It is expected that fault

interruption can cause a 2 p.u. transient. Propagation of a transient toward the array depends on the dc filter design. If capacitors are added to the normal smoothing inductor in a line-commutated converter, the magnitude of the voltage transient would be reduced. A further reduction could result from having a battery across the dc bus. However, interruption of large battery fault currents can give rise to voltage transients. It is likely the present efforts to develop converter equipment for utility energy storage batteries and fuel cells will give rise to equipment in which transients imposed on the source are limited. For the present, it is assumed that 2.5 to 3 p.u. at the array terminals represents a reasonable upper limit for converter related voltage transients. Transients are discussed further in Section 5.3.

As mentioned, a photovoltaic system can include an energy storage battery connected in parallel across the array-converter dc bus. The major impacts on the dc electrical system include an increase in available fault current, an increase operating voltage range, and a slightly more complex control system. It is assumed that a blocking diode is used to prevent battery current from flowing into the array buses. The parameters of interest in this array/module interface study would not be directly affected by the addition of a battery, aside from the aforementioned contribution to transient suppression.

For the most part, it appears that grounding on the dc side of the converter produces relatively small impact on converter cost but may add to the complexity of fault detection and interruption systems. A floating (i.e., ungrounded) system is preferred since two coincident faults are necessary to produce a failure. The second choice would be grounding at the midpoint of the array, and the third choice would be grounding one pole of the dc bus. The third method results in the greatest variability in fault current.

5.2 ARRAY SIZING AND DC WIRING

Modules or panels are fabricated at a factory and shipped to the plant site where they are mounted on an array framework and electrically connected to produce the desired system voltage and current. The total array surface area for any given plant power is a constant (2×10^7 square feet for the baseline 200 MW plant). This section discusses array configurations and electrical parameters needed for the required total array area.

Evaluation of converters (see Section 5.1.3) led to selection of a plant design in which arrays are electrically connected into groups. Each array group feeds one of a number of converters dispersed throughout the plant. Further, a converter dc current of 4000 amperes was selected as representative for the type of equipment needed. Thus, individual arrays are grouped to yield a 4000 ampere converter input. Connector availability and module

lead-wire considerations are expected to limit modules to currents on the order of 100 amperes (see Section 5.1.2).

For reasons of converter economics (see Figure 5-6), the system voltage should be above about 1200 volts dc. To minimize wiring cost (i.e., minimize interarray wiring) the modules are configured so that each array terminal is at the system voltage. Also, for reason of wiring economics, the positive and negative array terminals should be at the same end of the array. Thus wiring for a series string of modules starts at one end of each array, progresses to the opposite end, and then returns, terminating adjacent to the starting point. For this wiring scheme, module leadwires are located at opposite ends of the module at the center of the shorter dimension. This is illustrated in Figure 5-7. The frame of each module is connected to the system ground by means of a bolted connecting jumper to the array structure in order to minimize possible hazards to personnel.

Consideration of structural aspects, interarray access by installation and maintenance vehicles, shipping and installation, and other factors led to the selection of an array configuration with a sloped-face length of 16 feet. Each of one panels evaluated fits onto this array size in even multiples, thus facilitating comparisons. Installation costs, discussed in Section 6.2, indicate panels should be as large as possible. The 8 x 16 foot size was selected. Consideration of module

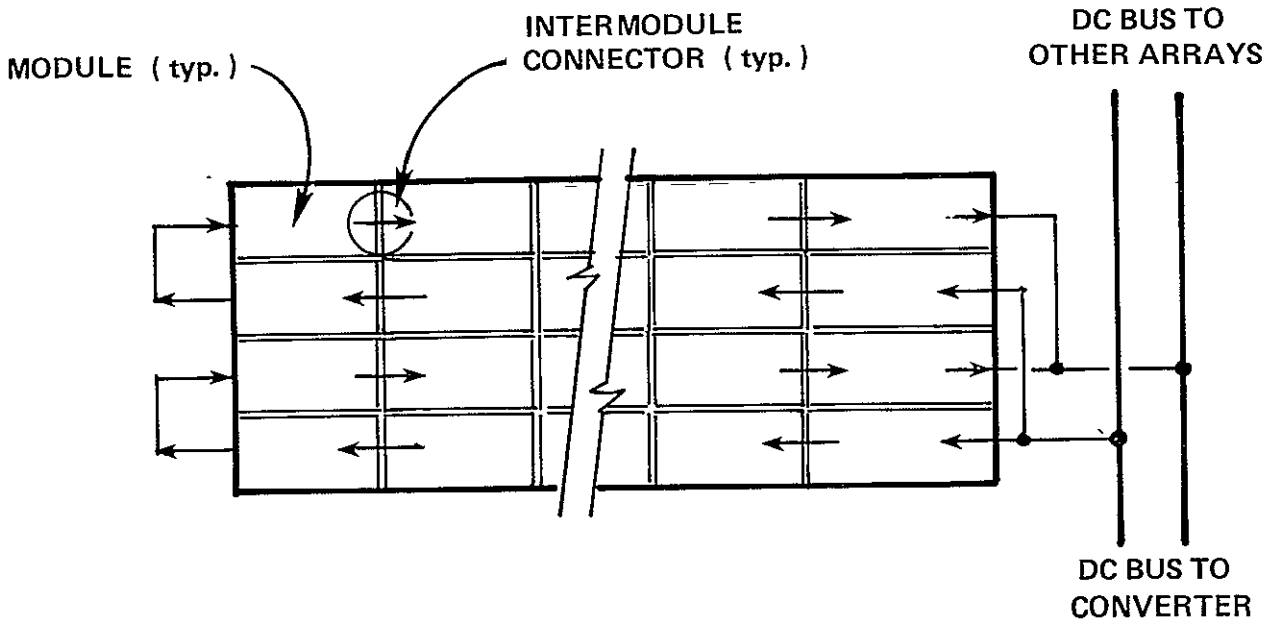


Figure 5-7 ARRAY WIRING SCHEMATIC

fabricating techniques and the size of easily available glass sheets indicate the 4 x 8 foot size is a good baseline module size. These two factors are combined and lead to 8 x 16 foot panels made up of four 4 x 8 foot modules for the baseline case. The array wiring for this panel configuration is shown by Figure 5-7. Each array has two series strings of modules mounted on it.

Array current is equal to twice the module current for two series strings of modules per array. The array voltage is the dc system voltage. The length of the array is obtained by dividing half the system voltage (i.e., the module string is configured down and back on the array) by the module's open circuit voltage and multiplying by the length of the module. These data are presented in Figure 5-8 for a 1500 volt system. The length of

the array at other system voltages is, of course, directly proportional to the length at 1500 volts.

The number of arrays per group or converter is determined by module current, which is a function of module size and voltage. Array length and the number of converters or power per group is determined by the system voltage. The cost of wiring between the arrays in a group and its associated converter is governed by the array current, number of arrays, and array spacing.

Figure 5-9 presents an estimate of the cost of this wiring as a function of module size for a 1500 volt system. These costs, normalized to dollars per watt (1975 dollars), represent the

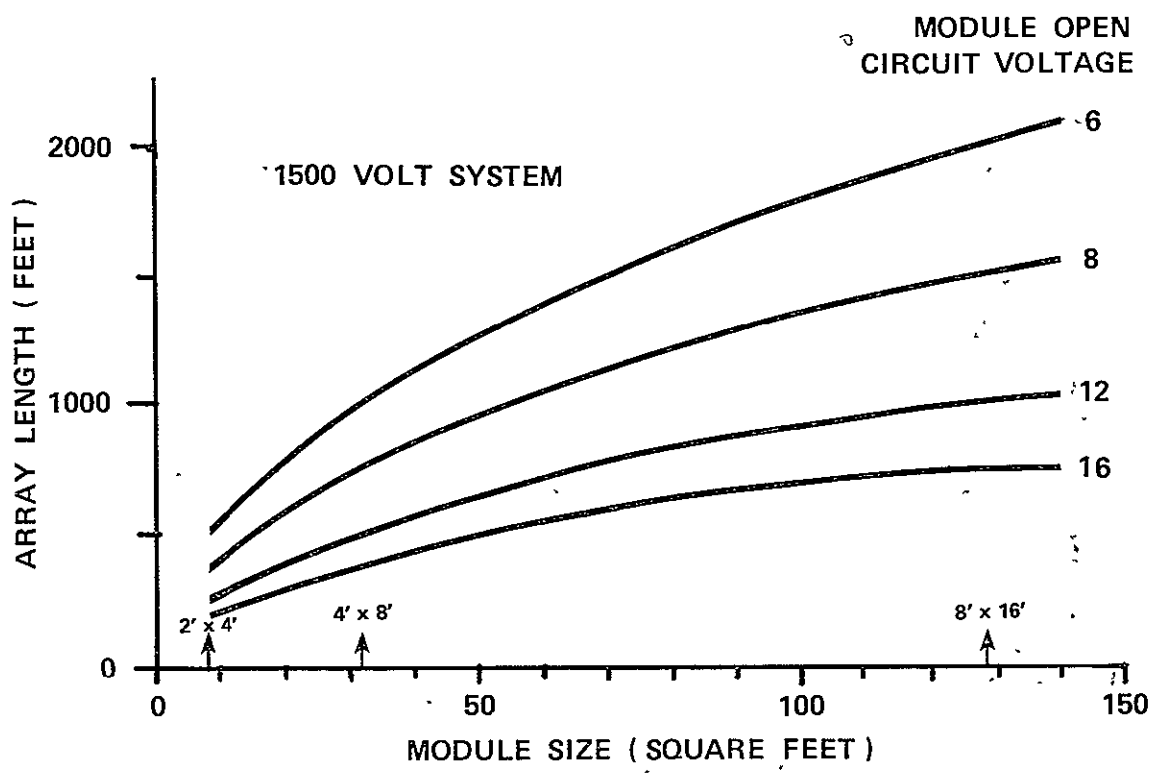


Figure 5-8 ARRAY LENGTH

total installed cost for a direct-buried, two-conductor, copper cable with an armor jacket. The cost of terminating the cable ends is included.

Array wiring requirements are also affected by system voltage. The cost of the wire itself does not increase greatly with increasing voltage. However, for a constant converter current rating, increasing the system voltage increases the power rating of the converter and the power output per array. The result is that increasing the system voltage reduces the quantity of arrays and power conditioning units required to assemble a plant of a given power rating. Figure 5-10 shows this effect of system voltage on wiring cost, normalized to the cost of 1500 volts. These costs vary approximately as voltage to the -0.8 power.

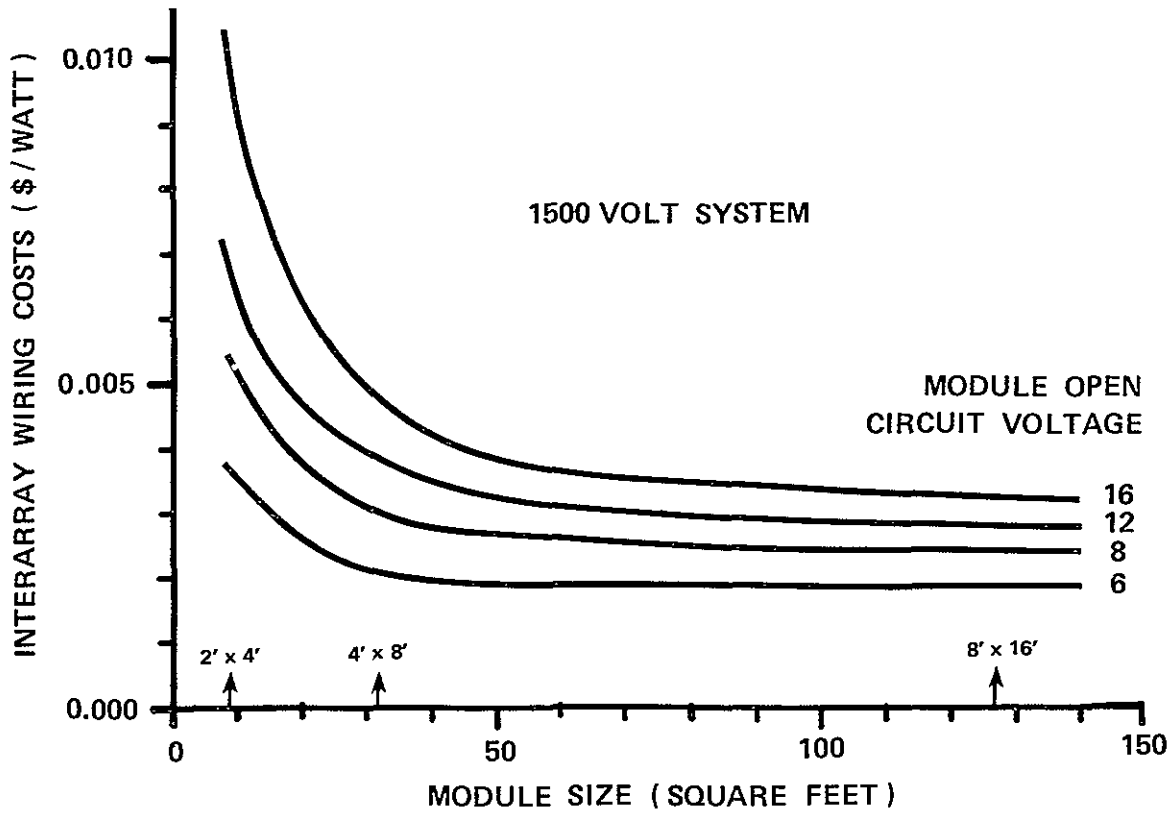


Figure 5-9 INTERARRAY WIRING COSTS

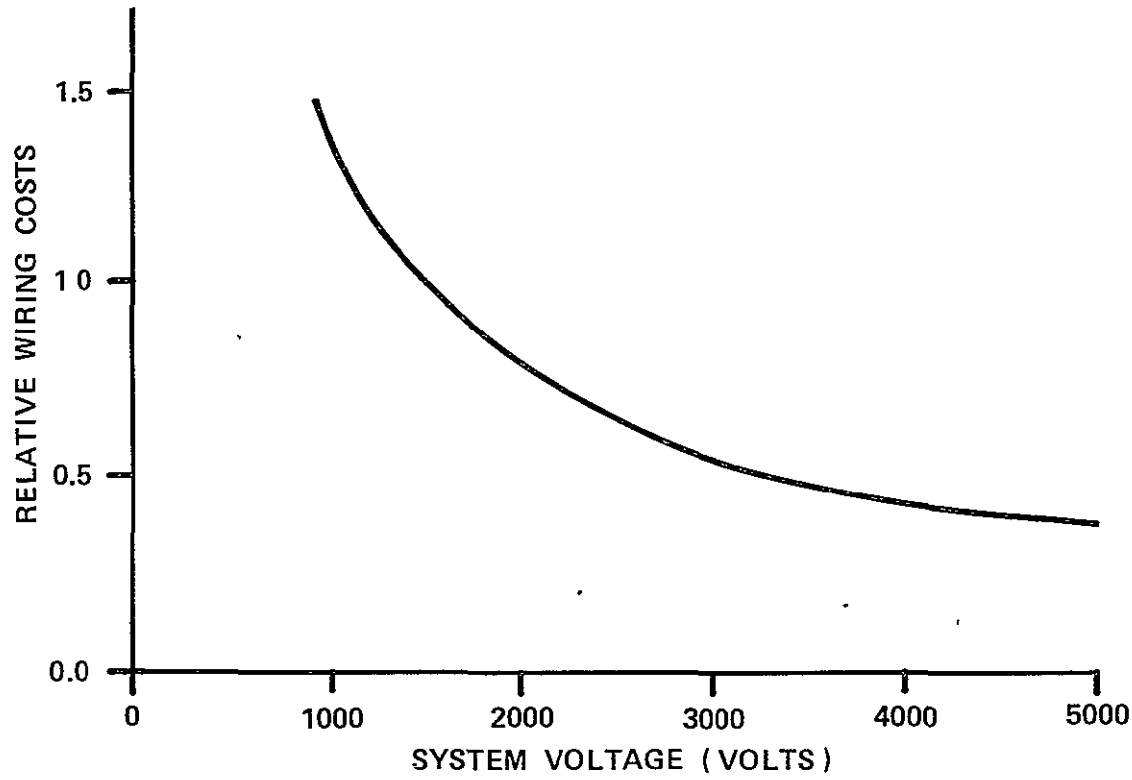


Figure 5-10 WIRING COST VERSUS SYSTEM VOLTAGE

Consideration of wiring cost presented in Figure 5-9 indicates that the module size should be 4x8 foot or larger. Consideration of the behavior of wiring cost versus system voltage (see Figure 5-10) indicates the system voltage should be as high as practical. These tendencies are the same as indicated by connector and converter costs.

Essentially the same electrical designs, developed herein, would apply to other plant sizes. Larger plant sizes would be comprised of additional array groups and smaller plant sizes would consist of fewer array groups. A 10 MW plant could consist of a single array group of the design postulated herein.

5.3 VOLTAGE TRANSIENTS

Electrical components and conductors must be insulated to withstand normal system operating voltages. Additionally, most electrical systems are subjected to occasional transient overvoltages which must be taken into account in specifying insulation levels.

To minimize permanent equipment damage, and to maintain continuity of service, it is standard industry practice to first shield and ground electrical equipment and also to apply auxiliary protective devices such as arrestors to limit surges to a safe level at very close distances to the protected equipment. The selection of appropriate insulation levels involves an economic comparison between the impulse strength of equipment insulation, the level of protection provided by auxiliary devices, and the probability and effect of exposing the equipment insulation to transient voltages in excess of its basic insulation level (BIL). Basic insulation levels for electrical power generating and transmission equipment are determined using a standard 1.5 x 40 microsecond test wave. This terminology indicates a steep wave front with a 1.5 microsecond rise time and a 40 microsecond period for the trailing edge to decay to one half the crest value. For the solar power plant considered herein, two major sources of voltage transients will affect the insulation design for the panels and modules. The first source

is lightning. The second source is converter equipment, which introduces transients via the dc bus.

In order to identify appropriate module insulation levels, the transient overvoltage conditions must be defined.

5.3.1 Lightning Stroke Transients

Lightning discharge currents usually start in clouds as an electrical breakdown of air due to potential differences of hundreds of millions of volts between clouds and the earth. Because of neutralization of the charges, the potential is reduced by the time the stroke hits the earth. Actual strike voltages depend upon the amount of current, the conductivity of the struck object, and the impedance of the path to the ground plane.

The magnitude of currents in lightning discharges may vary from 1000 A to 200 kA. Table 5-2 (Ref. 14) gives the range of currents terminating on grounded structures. In North America, about half the discharges have crest values exceeding 20 kA, and extreme values of at least 200 kA occur in about one stroke out of a thousand.

Table 5-2

RANGE OF LIGHTNING STROKE CURRENTS

Minimum Current Magnitude	Frequency of Occurrence
200,000 A	0.1%
100,000 A	0.7%
60,000 A	5.0%
15,000 A	50.0%

Lightning strokes have rise times on the order of a few microseconds.

The probability of a given surface receiving a lightning discharge depends upon its size, its distance from the equator, and the average number of thunderstorm days per year (i.e., isokeraunic level). Storm activity varies with geographic location and climate, with the highest activity in equatorial regions. In this country, the average is about 40 thunderstorm days per year. The isokeraunic levels for the U.S. as reported by the Environmental Science Service Administration are shown in Figure 5-11 (Ref. 15).

The large size of the array field results in a higher probability of having the structures struck by lightning than a more conventional utility substation. Using an isokeraunic level of 30 thunderstorm days per year for the Phoenix area (see Figure 5-11), an array field area of attraction of 4 square kilometers, and the methodology in Reference 16, the number of strikes into

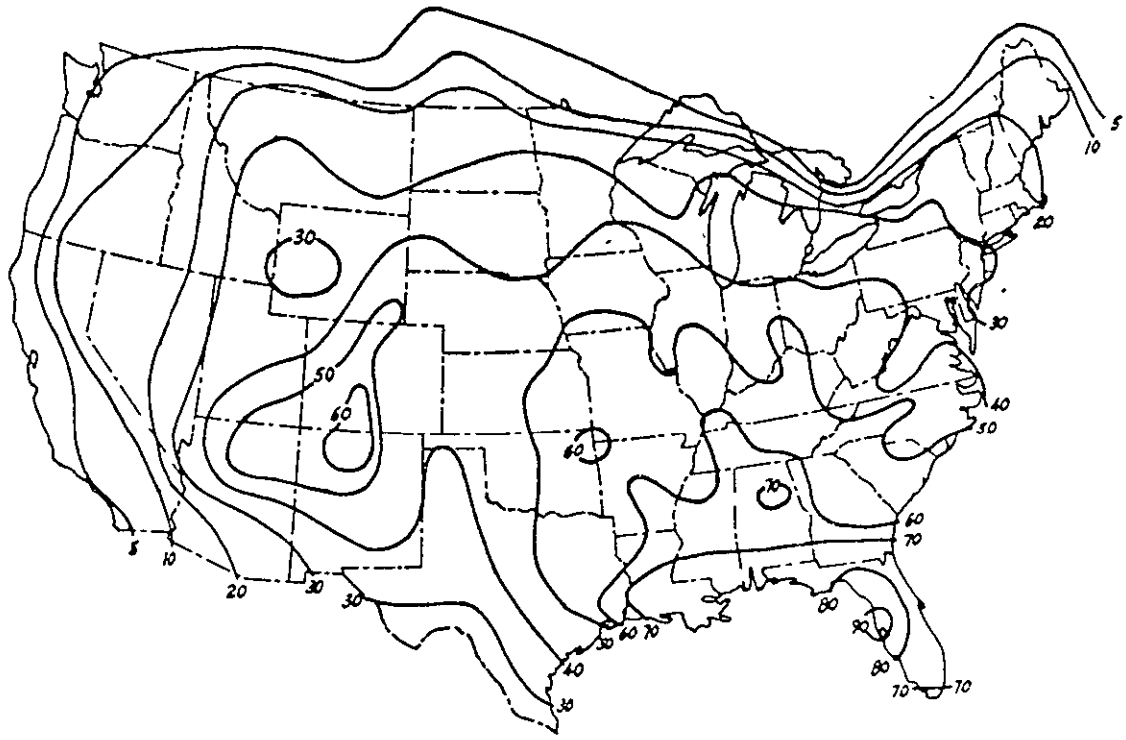


Figure 5 - 11 ISOKERAUNIC MAP OF THE UNITED STATES

the array field is estimated to range from 5 to 16 per year. This range can be used to determine the minimum economical insulation levels within the modules and the need for a grounding system for lightning protection.

Lightning strokes will be attracted to the array framework and discharged to ground. The lightning strike will raise the potential of the array structure, with respect to ground, during the period when the lightning current is flowing in the structure. The crest value of the voltage transient and the voltage wave shape in the array structure are determined by the

current magnitude of the lightning stroke, and the impedance of the array structure and ground grid system.

As a result of the current flow throughout the array support members, voltages will be induced upon the dc conductors within the adjacent solar cell modules. The magnitude of the induced voltage is governed by the inductive coupling between the array structure and module internal current-carrying components. This coupling is a function of the geometry and configuration of the conductive paths that are formed by the array structure, panel and module framing, and the dc wiring.

In the immediate area of the strike, module insulation will be stressed by a voltage equal to the difference in induced voltage between the structures and the dc wiring system. With modules interconnected electrically, the induced voltage will propagate through the system outside of the vicinity of the lightning strike. In these areas the module insulation will be stressed by the magnitude of this voltage as it propagates throughout the dc wiring system.

Lightning strikes to the array supports can be largely eliminated by providing grounding masts or ground wires to intercept direct strokes and conduct them to ground. Both lightning masts and overhead ground wires could be installed in a number of configurations depending upon economic and operating trade-offs. The general risk level used in the design of shielding systems is

to allow for a 0.1% exposure of a strike. The higher that masts and ground wires are installed and the closer together that they are placed, the greater the level of protection for the equipment which they shield. Several possibilities exist for these approaches.

Shielding masts could be placed in a square matrix pattern within the array field with each mast connected directly to the ground grid. The height of the mast and the elevation above grade of exposed objects to be protected determine the spacing:

A) High Masts. These would be approximately 50 feet in height, rising approximately 40 feet above the top of the array support framework. The horizontal separation would be on the order of 100 feet in both coordinate directions of the grid.

B) Low Masts. The spacing of these might be constrained by the 25 foot separation of arrays. These masts would be about 20 feet in height, rising approximately 10 feet above the top of the array support framework. This scheme would result in 4 times as many foundations as for the high masts, unless air terminals (i.e., lightning rods) could be attached directly to the array structure. This approach would have to be coordinated with panel washing requirements.

Alternately, horizontal ground wires might be run atop 45 ft poles parallel to the length of the arrays and spaced at intervals of 110 ft between rows of arrays. Typically, these wires are 3/8" EHS steel strand, hot dipped galvanized. The size of conductor is usually determined by mechanical strength considerations, rather than by current-carrying capacity.

Once a suitable air terminal has been chosen, the next consideration is the development of a buried earth-electrode system to dissipate lightning discharges to ground potential. Since the potential difference between the point of the lightning contact and the ground is directly proportional to the value of ground system resistance, it is desired to minimize this ground resistance to reduce the magnitude of surge voltages. Various types of ground grids can be designed employing horizontal conductors, rods, and ground wells. The extent to which these elements are utilized depends upon the characteristics of the soil and the desired ground resistance value.

Ground resistance is directly proportional to the resistivity of the soil. The resistivity of soils varies with the depth from the surface, the moisture content, and with the temperature of the soil. Because soil is frequently nonhomogenous, resistivity will often vary considerably in the vicinity of any installation. Representative values of resistivity for general types of soils are given in Table 5-3 (Ref. 17).

Table 5-3

RESISTIVITY OF DIFFERENT SOILS

Soil	Resistivity (ohm-meters) Minimum	Average	Maximum
Ashes, cinder, brine waste	6	24	70
Clay, shale, gumbo loam	3	41	163
Same, with varying proportions of sands and gravel	10	158	1350
Gravel, sand, stones with little clay or loam	590	940	4580

Some of the smaller utility substations and many industrial plants have grounding systems designed to a resistance of 5 ohms. The National Electrical Code states that the maximum resistance shall not exceed 25 ohms.

If a ground grid were constructed using copper conductors at approximately 30 foot intervals in both directions in a dry sandy soil of approximately 1000 ohm-meters specific resistance, a grid resistance of about 5 ohms would be anticipated. If a representative lightning stroke of 20 kA were to hit an overhead air terminal, a crest voltage of 100 kV would be developed to ground as the charge dissipates. This voltage may be reduced up to 60% if ground wells down to the water table are incorporated to reduce the ground resistance down to 2 ohms or less.

Connecting the overhead air terminals directly to the ground grid would lessen the voltage rises in the array modules. However, some inductive coupling to the modules may exist, which would cause observable voltages to be induced. Further investigation, including some modeling, should be carried out to determine the maximum voltage stresses to be expected within the modules.

5.3.2 Lightning Flash Transients

In addition to the transients induced by lightning stroke currents propagating on the grounding system, the flash of light from a nearby lightning strike may cause a transient voltage across the array terminals. The level of light from a nearby lightning flash is estimated to be on the order of 50 suns.

If it is assumed that the spectral distribution of this light energy duplicates that of sunlight, the magnitude of the resultant transient can be estimated. Using a standard form of the equation (Ref. 18), the open circuit voltage, V, of a solar cell is given by:

$$V = \frac{kT}{e} \ln(1 + g_o L/gL')$$

Taking the ratio of known open circuit cell voltages at normal insolation levels to that at 50 suns results in module transient voltages on the order of 1.2 to 1.7 per unit. The magnitude

depends on the assumptions made for the physical properties of the semiconductor material and saturation effects.

At present it does not appear that this effect will govern setting of module insulation levels.

ORIGINAL PAGE IS
OF POOR QUALITY

5.3.3 Converter Transients

Converter-caused transients are discussed in Section 5.1.3 where it is concluded that such transients may reach 2.5 to 3 per unit. The exact magnitudes of these transients are dependent on the converter and plant design.

5.3.4 Protective Devices

The effects of transient overvoltages on module insulation can be ameliorated by the installation of protective devices, such as voltage clamps, in the dc system. When located at the array terminals, voltage clamps will act to limit the magnitude of any transient at the array.

For the array wiring scheme shown in Figure 5-7 (i.e., two series strings of modules per array), two clamps would be used per array. The positive terminal of the two module strings are connected together at the dc bus and to ground through a clamp. A similar arrangement is used at the negative terminal.

Generally, this type of device is a nonlinear resistor whose resistance decreases as the voltage applied across its terminals increases. Such devices are available from several manufacturers, including Westinghouse's "Voltrap," General Electric's "MOV" (metal oxide varistor), and Panasonic's "ZNR Transient/Surge Absorber."

The ZNR device is a ceramic/zinc-oxide voltage clamp, manufactured by the Panasonic Division of Matsushita Electric Corporation of America. Typically, this device draws less than 1 milliampere at the rated system voltage. At about 2 p.u. of system voltage, it shunts approximately 25 amperes. At 3 p.u., it will shunt approximately 500 amperes.

Prices for Panasonic's ERZ-C14 and ERZ-C20 models range from about $600 to $1400 each, depending on system voltage. These prices are in 1977 dollars and for the range of quantities needed for a 200 MW plant. The variation of price and quantity needed varies with array system voltage in a manner that results in an almost constant cost of approximately $0.01/watt (1975 dollars) for the range of voltages under consideration. Costs for weather proofing and installation must be added.

The effect of this type of device, and the entire lightning and surge protection design, should be the subject of further study, as discussed in the following section.

5.3.5 Insulation Level

Final setting of transient voltage insulation levels for the modules, connectors, and wiring is governed by aspects of plant design that are beyond the scope of this present study. In particular, estimating the level of expected transient voltages requires consideration of at least the following:

- The design of a lightning protection system
- The coupling between the lightning protection system, array framework, and dc wiring system
- The impedance of the array framework to ground
- The resistance of the soil at the selected site
- The isokeraunic level at the selected site
- The size and configuration of the plant
- The type of converter used
- The impedance of any energy storage battery across the dc bus
- The impedance of the dc wiring system to the array terminals
- The impedance at the array terminals
- The characteristics of auxiliary protective devices.

After consideration of the above factors, as far as is possible at the present stage of plant design, it is estimated that expected values of transient voltages will be on the order of 2.5 to 3 times the dc system voltage. This estimate is preliminary in nature and should be the subject of further study as plant design progresses.

Section 6

MAINTENANCE

Once the solar power plant has been put into service, maintenance activities will be needed to keep the plant operating as designed. Provisions for these future activities must be considered during the design of the plant and, therefore, in the design of the modules and the array interface.

Three aspects of maintenance (module cleaning, failure detection, and replacement) are addressed in this section. Module replacement applies also to initial installation of the modules, since essentially the same equipment and procedures are used in both instances. Cost data for all three maintenance aspects are presented and their impact on design noted. Unless otherwise stated, all costs are given in 1975 dollars. A brief discussion of warrantees is also included.

6.1 ARRAY CLEANING

It is known that the power output of the plant will decrease with time because of the accumulation of dust and dirt on the array surfaces. Thus, cleaning of the arrays to restore lost power (and revenue) becomes important. Two methods of array cleaning, manual and automated, were considered and their costs were estimated. Additionally, curves have been developed to show the

effects on plant revenue and optimum frequency of cleaning with cost of power and rate of dirt accumulation as parameters.

6.1.1 Cleaning Methods

The cleaning methods proposed and their costs are based on a 200 MW plant (2×10^7 ft^2 of modules) located in the Phoenix area. The plant and array configuration are as described in Sections 3 and 4. It is assumed that the surfaces to be cleaned are glass or glass-like in nature as far as cleaning is concerned.

Manual Cleaning. The manual array cleaning method consists of conventional window washing techniques. Standard glass cleaning tools are used (i.e., buckets, brushes, squeegees, and chemicals). A cleaning subcontract is proposed. Since there are no window cleaner's unions in the Phoenix area, a wage scale of $5.00 per hour is used for unskilled labor hired to perform the washing. A total subcontract labor cost of $8.00 per hour is obtained by adding a 60% burden to the base wage. The burden includes the cost of materials (e.g., brushes, chemicals, etc.) and the subcontractor's overhead and profit. Productivity estimates obtained from commercial contractors in conjunction with the cost estimates indicated that one man will be able to wash 20,000 ft^2 per 8 hour shift. Combining the above figures yields a one-time array cleaning cost of $65,000. This

translates to 3.25 mills per ft^2 per cleaning for the manual method.

Water consumption for manual cleaning was estimated to be 10 gallons per shift per man. It is assumed that there is no water supply available at the site. Therefore the capital cost of wells and a purification system was estimated. The amortized cost of the water supply system, along with its operating and maintenance costs, resulted in an annual water cost of $7,000 per year. This cost must be added to the above labor costs.

Automated Cleaning. At present, automated window washing machines are used on many tall buildings, including: the World Trade Center, New York; Sears Tower, Chicago; Century Plaza Towers, Los Angeles; and Bechtel's San Francisco headquarters. Discussions with a manufacturer of this equipment, Steeplejac Division of Alpana Aluminum Products, Inc., indicate that a suitable machine can be built for array cleaning.

Currently available machines utilize spray nozzles and non-rotating brushes followed by squeegees. Excess water is vacuumed from the surfaces, filtered, and reused. Mullions on the building surface form a captured track along which the self-contained unit is propelled by cables.

A similar machine is proposed for use in array cleaning. In this case, however, the separate washing head contains only the spray

nozzles, brushes, and squeegees. The washing head proper is about 8 inches wide by 16 feet long (the sloped length of the array). It is mounted on a framework approximately 8 feet wide to provide for tracking along the arrays. It is estimated that the total weight of the washing head unit which travels on the array framework is less than 1000 lb. Wheels on the washing head framework capture the unit to the array framework. It is estimated that the squeegees will exert a force of 10 lb per linear foot of sloped array width (e.g., 160 lb for a 16 foot array). Use of non-rotating brushes minimizes vibrational forces on the arrays.

The washing head is propelled along the array by a separate rubber-tired service unit traveling on the ground next to the array. A guidance system tracks the edge of the array framework. Motive power for propulsion and the pumps is propane gas. Water tanks, pumps, and other heavy equipment are mounted on the ground unit. Hoses and structural framework connect the ground unit to the washing head. Use of this separate service unit on the ground minimizes the weight of the washing head on the array. Therefore no additional structural support is necessary in the array framework to accommodate the washing head.

According to the manufacturer, the unit can travel at 25 to 30 feet per minute. Thus the unit can wash 400 to 480 ft^2 per minute on a 16 foot array.

Steeplejac estimates that the water consumption per machine will be 8 gallons per 8 hour shift for daytime operation and 1 gallon per machine if the arrays are washed at night. Only about 1 gallon of water is consumed per machine per day. However, the entire tank of dirty water is disposed of after each 8 hour shift. Thus, the water requirement is 50 gallons per mechanical washer per 8 hour shift.

Budgetary cost estimates for a machine designed for this application were obtained from Steeplejac. These capital cost estimates, expressed in 1975 dollars, are presented in Table 6-1 below.

Table 6-1

AUTOMATED WASHER CAPITAL COST

Quantity	Price per Unit
Design and 1 prototype machine	$275,000
2 to 10 machines	$150,000
11 to 25 machines	$130,000

The automated cleaning costs were estimated on the following basis:

- Movable structural supports are included to allow the machine to cross interarray spaces.
- An allowance is made for minimal surface preparation of the ground for the service unit to travel on.
- Purchase of automated washers and overhaul every 5 years of the washers' 20 year life are included.

- Labor, operating, and maintenance costs are included.
- Squeegees are replaced after every 500 hours of operation.
- Water and propane fuel costs are included.

Separate estimates for total washing cost were made for 2, 5, and 10 automated washers. Other washing costs were obtained by interpolating the variable portions of the three complete estimates. Total washing costs are presented in Figure 6-1 in terms of dollars per square foot of array surface as a function of wash interval (1975 dollars). Manual washing costs are also included. The reduction in automated washing cost as wash interval decreases is mostly due to price discounts as the washers purchased increases. These costs are used in Section 6.1.2 to evaluate the economics of cleaning.

6.1.2 Cleaning Economics

The reason for cleaning the accumulated dirt from the arrays is to restore the plant's power output, thereby increasing the revenue from the plant. However, what must be increased is net revenue. That is to say, the cost of cleaning should not exceed the revenue from the accompanying increase in energy sold. This problem is analyzed by considering the cleaning costs developed in the preceding section in conjunction with a parametric set of dirt accumulation rates and values of energy from the plant.

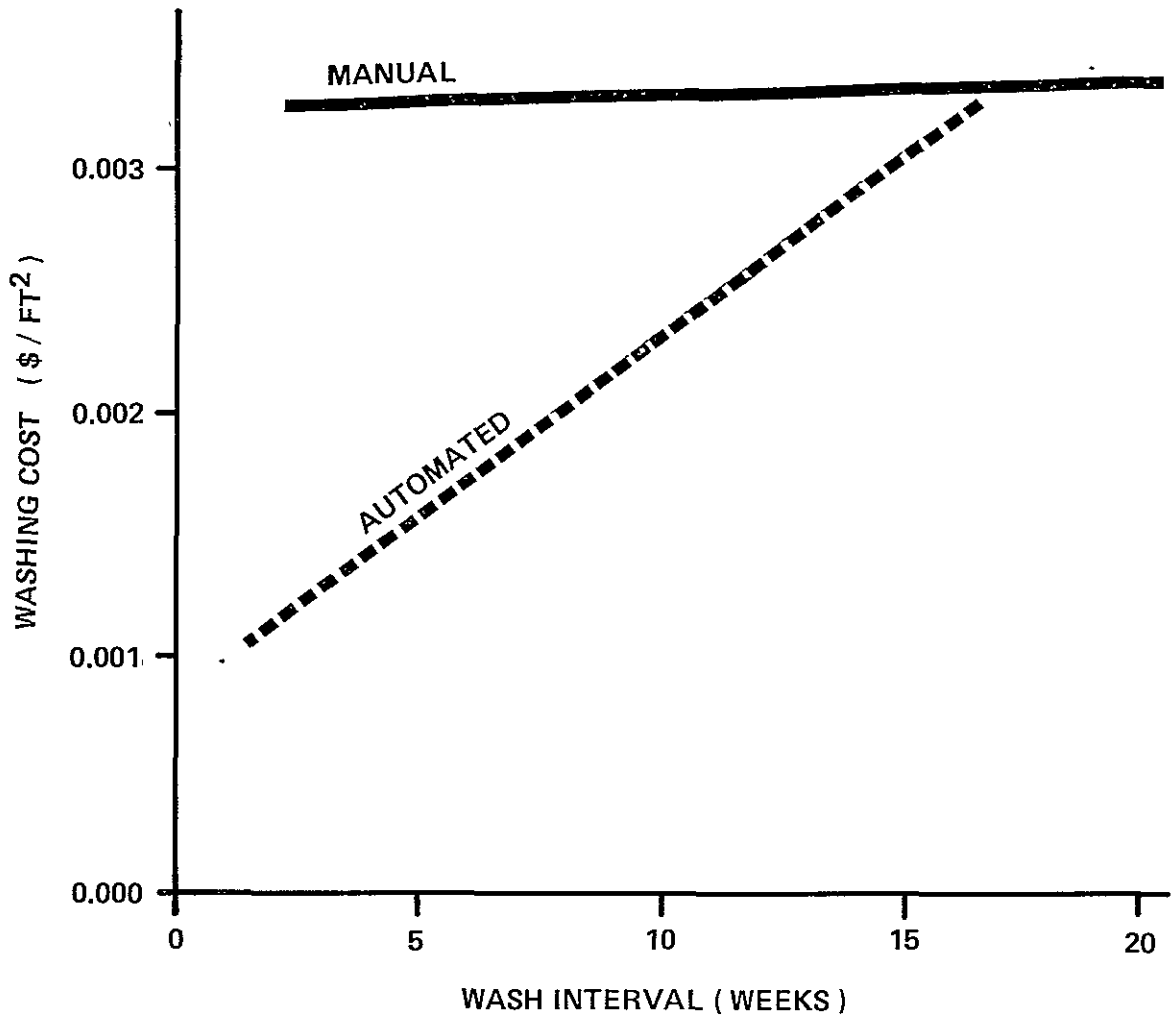


Figure 6-1 ARRAY WASHING COST

It is known that the array power output will decrease with time as a result of dirt accumulation. Unfortunately, little information is available on exactly how this degradation varies with time. For purposes of this analysis it is assumed that array power will decrease exponentially with time as shown in Figure 6-2. A complete analysis would account for geographic and seasonal variations.

As can be seen in Figure 6-2, the assumed variation in power output asymptotically approaches a final value, 1-K. Values from

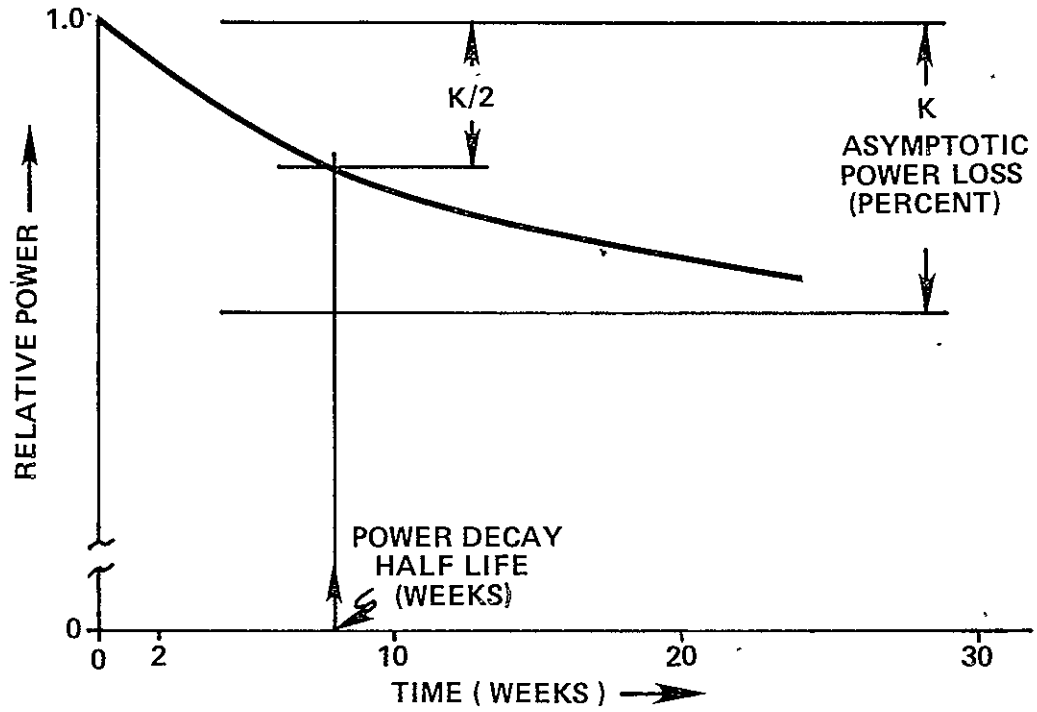


Figure 6-2 ARRAY POWER VARIATION

0.95 to 0.65 of the initial value were considered parametrically. That is, asymptotic power losses, K, ranged from 5 to 35 percent.

In addition to these final values, the shape of the curve was determined by specifying how fast final values are approached. This is accomplished by specifying the length of time (i.e., power decay half-life) taken to reach one half of the asymptotic power loss, K/2. Values of 2, 4, 8, 16 and 32 weeks for the power decay half life were evaluated for each value of asymptotic power loss.

In this analysis, only power loss due to dirt accumulation is considered. Effects of long-term module degradation, encapsulant yellowing, etc., are not included. Further, it is assumed that washing the arrays restores the power to its initial value, and

that after each washing, the pattern of exponential decrease in power is repeated. This is illustrated in Figure 6-3.

The areas under the two curves can be integrated to determine the plant's energy output with and without washing. The cross-hatched area in Figure 6-3 shows the increase in energy output obtained by washing. This analysis of cleaning economics is based on JPL's premise that the plant's average daily energy output is given by multiplying its peak power rating by 5 hours and on the assumption that the plant would operate 365 days per year.

The plant's annual energy output can be expressed as a function of asymptotic power loss, power decay half-life, and wash interval. Net annual revenue is then obtained by multiplying the

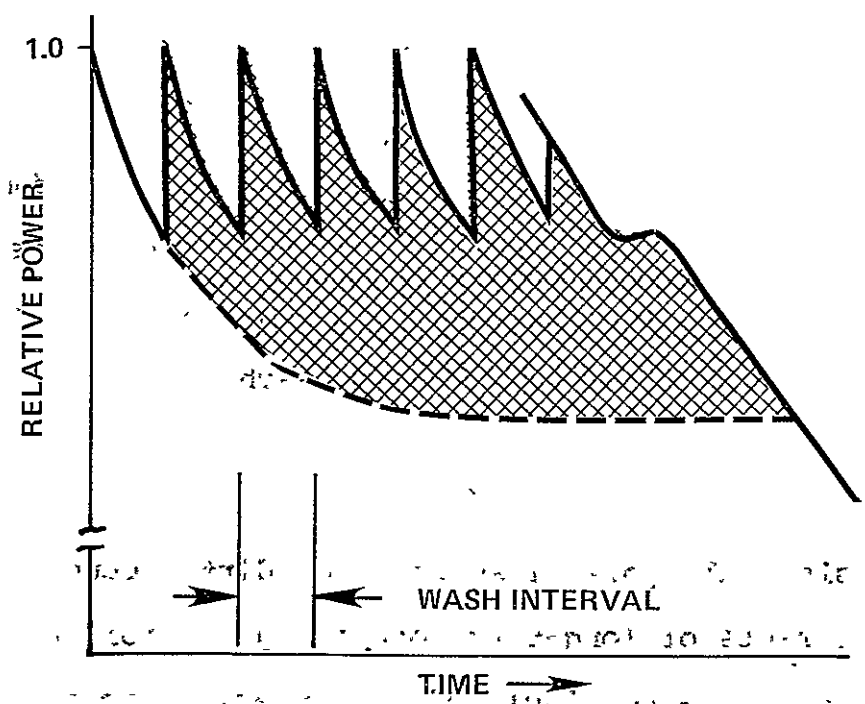


Figure 6-3 ARRAY POWER VARIATION WITH WASHING

energy by its unit cost (i.e., mills/kWh) and subtracting the cost of automated washing (from Figure 6-1).

The results of one such set of calculations are presented in Figure 6-4, which shows net revenue increase as a function of wash interval. This particular set of curves is for a power cost of 35 mills/kWh and a power decay half-life of 2 weeks. The curves are normalized by dividing the net annual revenue with washing by the revenue without washing and are expressed as a percent increase.

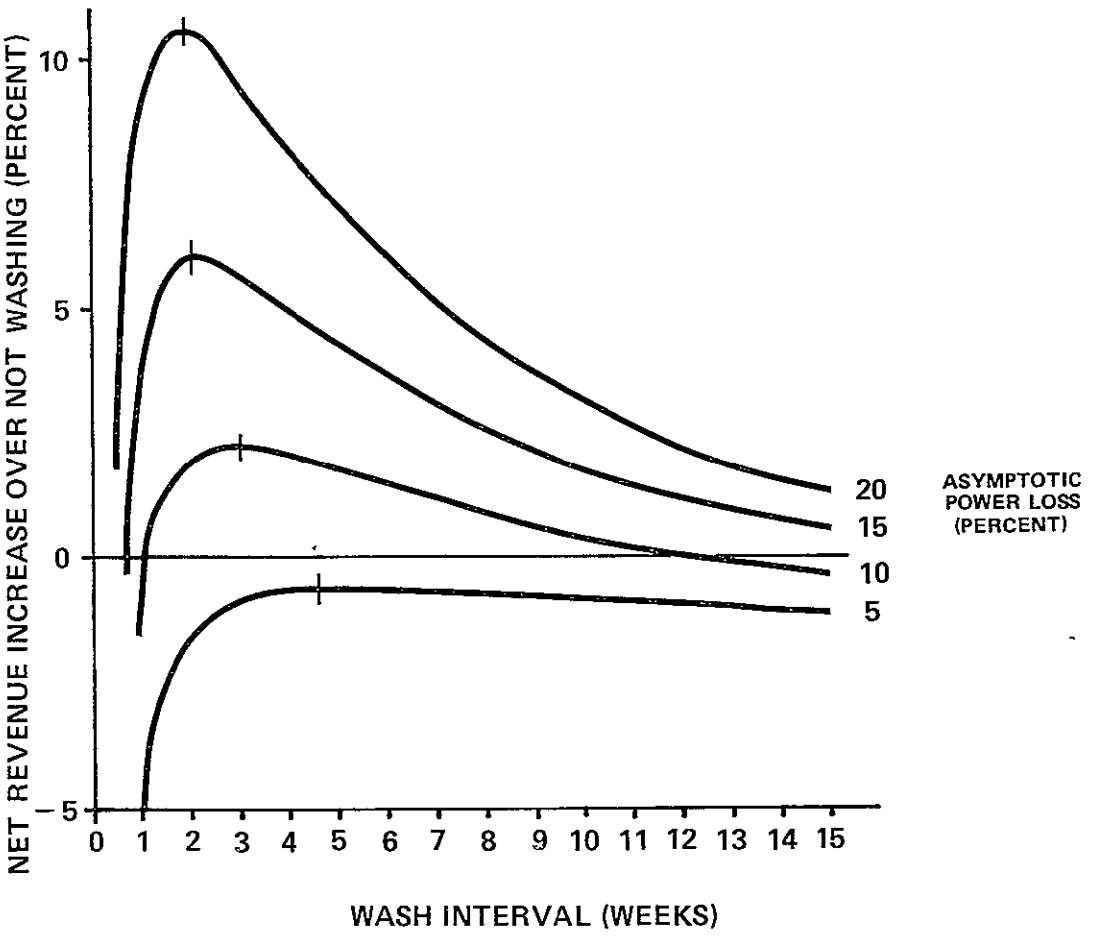


Figure 6-4 NET REVENUE VERSUS WASH INTERVAL

From Figure 6-4, it can be seen that for a 5% asymptotic power loss it does not pay to wash the arrays (for a 2 week decay and 35 mills/kWh). It can also be seen that there is an optimum wash interval which maximizes net revenue for each value of asymptotic power loss. These maxima are indicated on each of the curves.

Such maxima in plant net revenue exist for other power decay half-lives and energy costs. Figures 6-5 through 6-9 show these maximum increases in net revenue and optimum wash intervals for several costs of energy. In using these figures, an appropriate cost of energy is selected and the position on the graph is located for the dirt accumulation rate thought to exist. For example, for an energy value of 45 mills/kWh, an asymptotic power loss of 10 percent and power decay half-life of 8 weeks (i.e., the power degrades to .95 in 8 weeks), Figure 6-6 shows the optimum wash interval to be 4 weeks. Also, in this case, washing the arrays every 4 weeks yields a plant net revenue about 4 percent higher than for not washing. The range of parameters encompassed by Figures 6-5 through 6-8 should permit estimates to be made of the advantages of washing for most actual situations.

Figure 6-9 summarizes the foregoing data and presents them with a slightly different normalization. In this figure, the net plant revenue is compared with that of an ideal plant in which there is no power loss due to dirt accumulation or other factors. Data for net revenue with washing (shaded regions) and without washing (solid lines) are presented for two rates of dirt accumulation

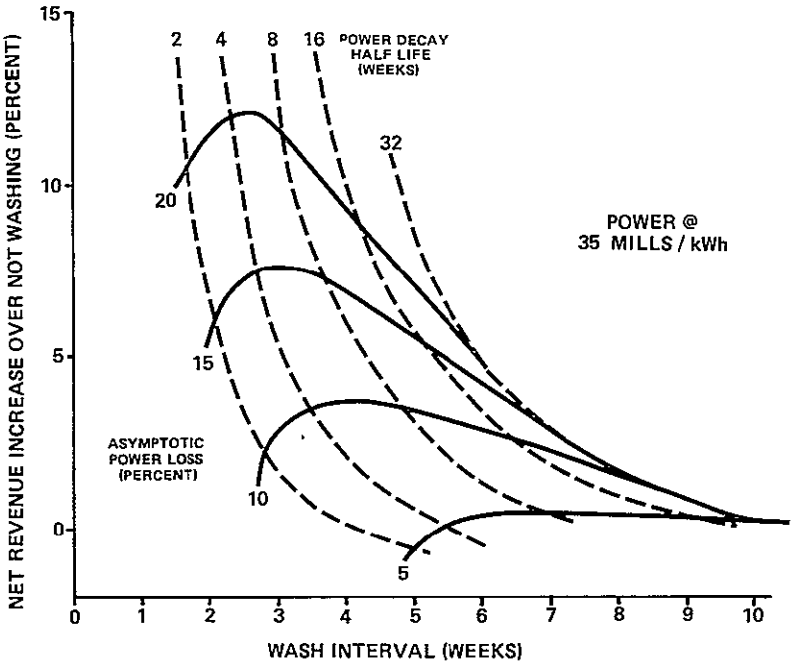


Figure 6-5 NET REVENUE INCREASE WITH WASHING (35 MILLS/kWh)

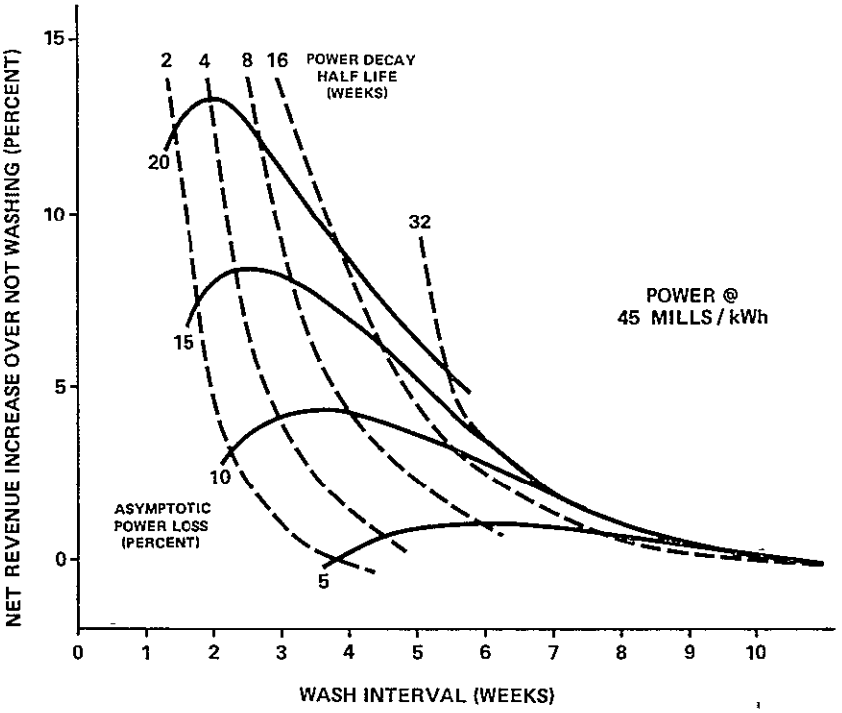


Figure 6-6 NET REVENUE INCREASE WITH WASHING (45 MILLS/kWh)

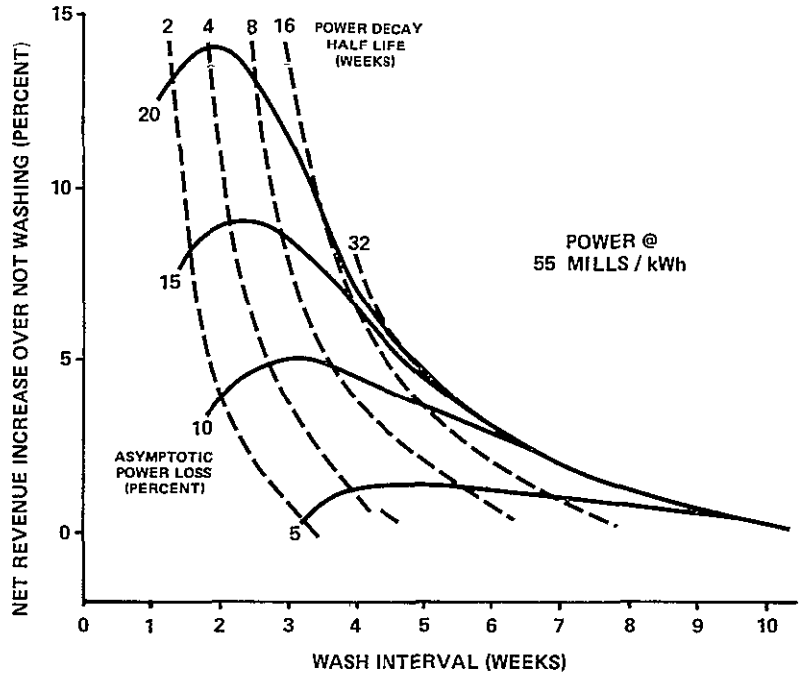


Figure 6-7 NET REVENUE INCREASE WITH WASHING (55 MILLS/kWh)

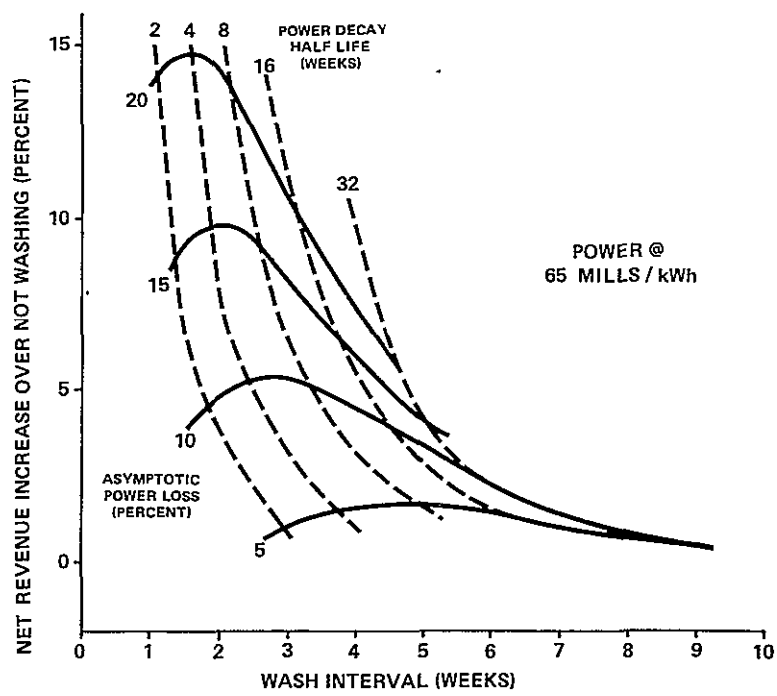


Figure 6-8 NET REVENUE INCREASE WITH WASHING (65 MILLS/kWh)

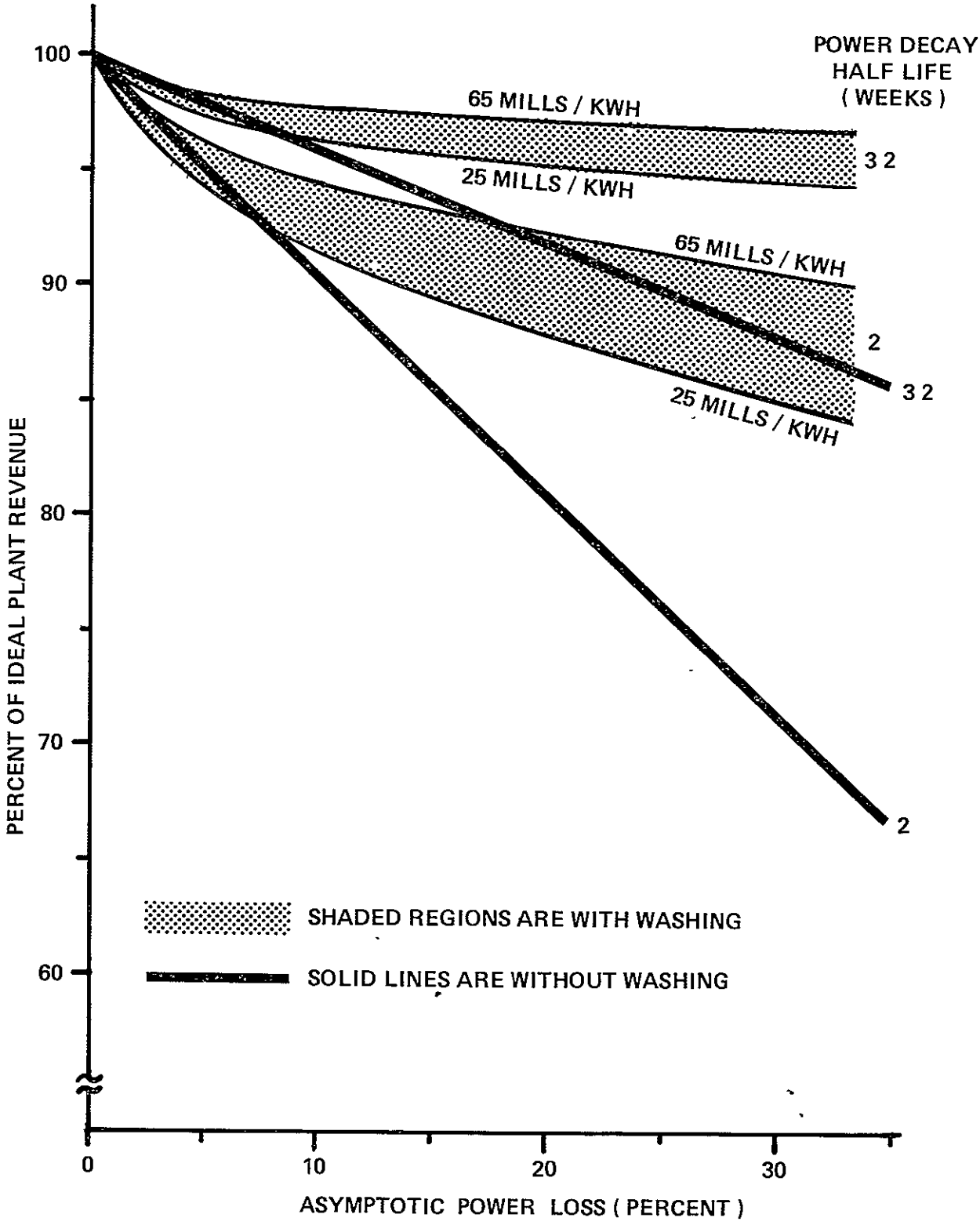


Figure 6-9 IMPACT OF WASHING ON REVENUE

(i.e., 2 and 32 weeks to reach half of the asymptotic power loss). Without washing the annual energy from the plant with dirt accumulation and from the ideal plant are both multiplied by the same energy cost. Thus, normalizing eliminates the energy cost factor. Whereas washing decreases gross revenue by an amount that is not related to energy cost, the net revenues with washing are dependent on energy cost.

As might be expected, washing the arrays becomes more advantageous as the amount and rate of power loss due to dirt accumulation increases. Also, Figure 6-9 and the foregoing analysis show washing will increase the plant's net revenue in cases where the asymptotic loss is greater than 8 percent and energy is sold at 25 mills/kWh, and in all cases if energy is sold at 65 mills/kWh.

The foregoing analysis is based on the smooth variation of washing cost with wash interval shown in Figure 6-1. Since an integral number of machines must be used, the actual washing cost is a discontinuous function. However, use of the more accurate curve results in discontinuous revenue data which cannot be easily plotted to convey the essential results of the analysis. Thus the smoothed, average curve is used.

Additionally, the present analysis is based on an unvarying exponential rate of dirt accumulation for an entire year. This obviously is not the case. Rain and seasonal weather variations

will alter the assumed pattern. The curves must be cautiously used to approximate impacts on annual revenue by summing contributions for periods of time during which dirt accumulation is uniform. Thus, it is felt that the analysis presents a reasonable methodology that is useful for a first order approximation.

The foregoing analysis would change little for larger plants (e.g., 1000 MW). Washing cost may decrease slightly owing to volume purchase discount of washing units (see Table 6-1). For small plants (e.g., 10 MW), washing cost would increase, since the full capability of a single washer would not be fully utilized and the manual washing method might be preferred.

6.2 PANEL INSTALLATION AND REPLACEMENT

Methods of installing and replacing panels on the array framework are discussed in this section. The same basic methods and equipment are used for initial installation and replacement. Handling methods and associated costs are developed for three panel sizes (2x4 foot, 4x8 foot, and 8x16 foot). These costs are then used in Section 6.3 to evaluate the economics of panel replacement.

6.2.1 Handling Methods

Two basic methods of handling are developed: one for the small sized panels, and a second method for the two larger panel sizes.

Small Panels. The method developed for initial installation of the small (2x4 foot) panels in 2 years requires 16 crews of eight members each. Two members of each crew are involved in receiving operations and six in installing the panels.

After arriving at the jobsite, boxes of panels are unloaded by means of a conventional forklift and placed on a small trailer. These trailers are then towed and deposited along the array area being worked on. Two of the crew unpack and move the panels to a movable scaffold. Two pairs of workers on the scaffold take the panels, fasten them into place, and make the electrical connections. As a section is completed, the scaffold is moved along the array and the operation is continued.

Large Panels. The same basic handling method is used for both the 4x8 foot and 8x16 foot panels. For the 8x16 foot panels, the panels arrive at the jobsite in reusable 10x9x17 foot carrier boxes in an air-cushioned, flat-bed truck. Each truck, carrying two boxes, is driver into the array area. A modified straddle-carrier, such as the Drott Company's Travelift, straddles the truck and loads the boxes onto a platform on the carrier. The boxes are placed in a vertical position as shown by Figure 6-10.

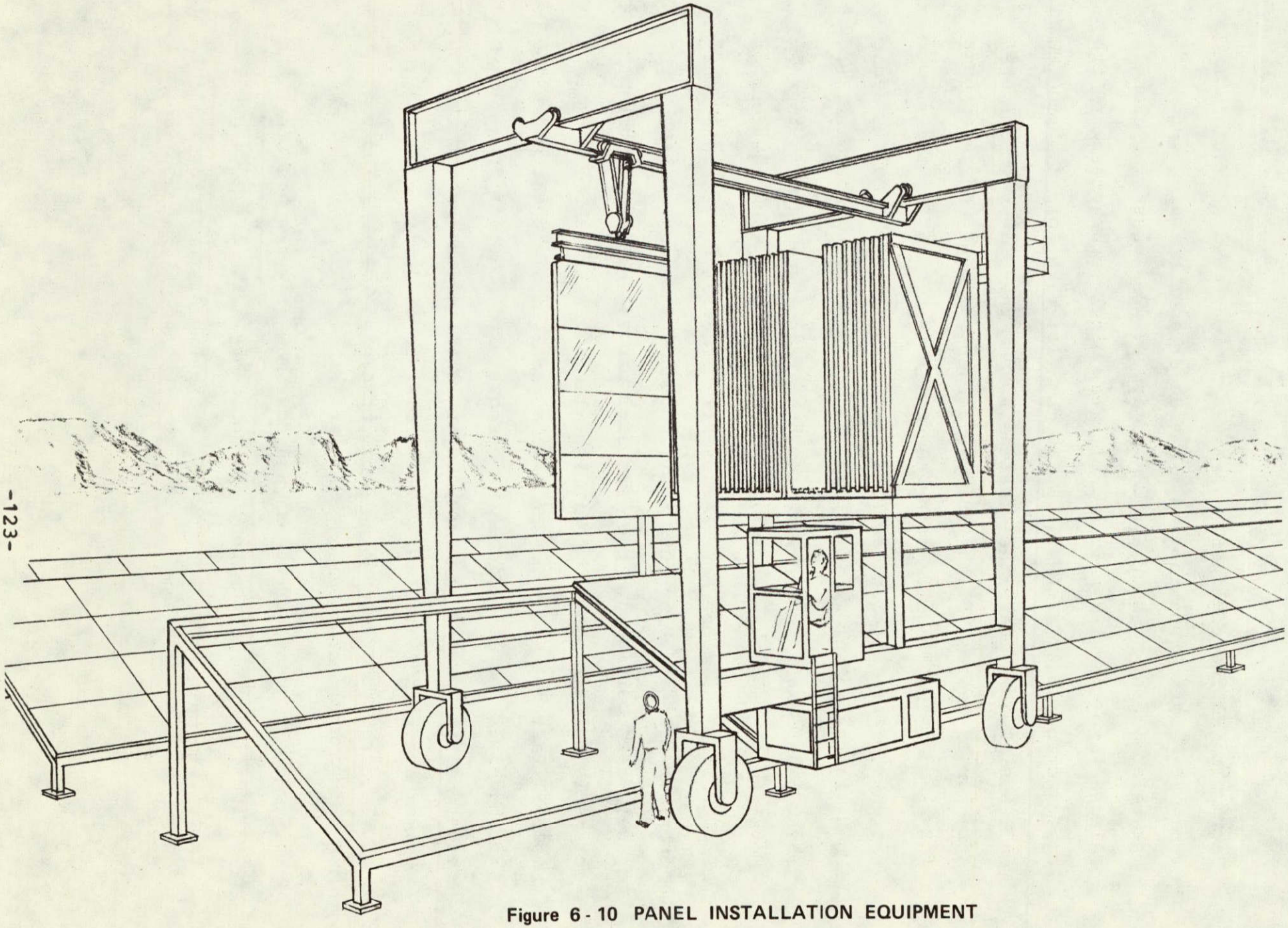


Figure 6 - 10 PANEL INSTALLATION EQUIPMENT

Having loaded the boxes of panels, the carrier straddles the array framework. The top and one side of each box are removed to provide access to the panels. One worker connects a spreader bar to the top of a panel. The panel is then lifted slightly and moved sideways, along the array. The panel is lowered vertically and positioned over the fasteners on the lower transverse structural member of the array framework, guided by a member of the crew on the ground. After the panel is nested in the lower fastener, the lifting cable is slackened while the hoist saddle is moved toward the top of the array. The panel pivots on its lower edge and is inclined to the array slope, coming to rest with its top edge against the top structural member of the array framework. A member of the installation crew guides the crane-operator/driver during this positioning of the panel. After the panel is positioned, the spreader bar is unhooked. While the crane is being repositioned to install the next panel, a crew member fastens the top edge on the panel, and the worker on the ground mates the electrical connectors and fastens the lower edge. This process is repeated until all of the panels in both boxes have been installed. The carrier is then driven to the end of the array to off-load the empty boxes and load full boxes.

The same equipment, procedure and four-man crew are used for the 4x8 foot panels, since they are too heavy to be lifted manually. Except, in this case, more trips to the end of the array will be needed.

6.2.2 Handling Costs

Cost estimates were developed to compare the methods of handling different-sized panels. For initial installation, an average direct manual wage rate of $17.00 per manhour (1975 dollars) was used for construction crews. Replacement of panels is assumed to be done by the utility's maintenance crews having an average direct manual wage rate of $14.00 per hour. Added to these costs are the distributable field costs of 50 percent and 25 percent of direct manual labor for installation and replacement, respectively.

Each of the handling methods for the initial installation was based on the same two-year installation schedule for a 200 MW plant. However, the total labor work force varies with the method employed.

Initial Installation. The initial installation of 2x4 foot panels is estimated to require 500,000 manhours for the 2.5 million panels. At 1975 price levels, this labor-intensive method would cost $9.0 million. This installation cost does not include engineering, home office support, or contingency.

A 200 MW plant requires 625,000 4x8 foot panels. The initial installation would require 160,000 manhours and would cost 3.8 million dollars at 1975 levels. Included in this estimated

installation cost is the purchase and modification of seven straddle carriers.

The largest panel size, 8x16 foot, requires the least field handling, which reduces the comparative installation cost. The installation of 156,000 of these panels would require 67,500 manhours and is estimated to cost about $1.7 million (1975 dollars). This cost includes three straddle carriers and modifications.

The above cost estimates, normalized to dollars per watt, are graphically summarized in Figure 6-11. These costs vary approximately as panel size to the -2/3 power.

Field installation of panel sizes larger than 8x16 foot could possibly reduce installation costs, but the 8x16 foot panel is the largest practical size for truck transportation without special truck routing and permit procedures.

Complete Replacement of Panels. It is assumed that after the photovoltaic power plant has been in operation for approximately 15 years, all of the installed panels will be systematically replaced with new panels. This scheduled "maintenance" operation is similar to the initial construction installation. For the 8x16 foot panels, two of the three straddle carriers used in the initial installation are used in the replacement operation. The straddle carrier and a four-man crew move down an array and

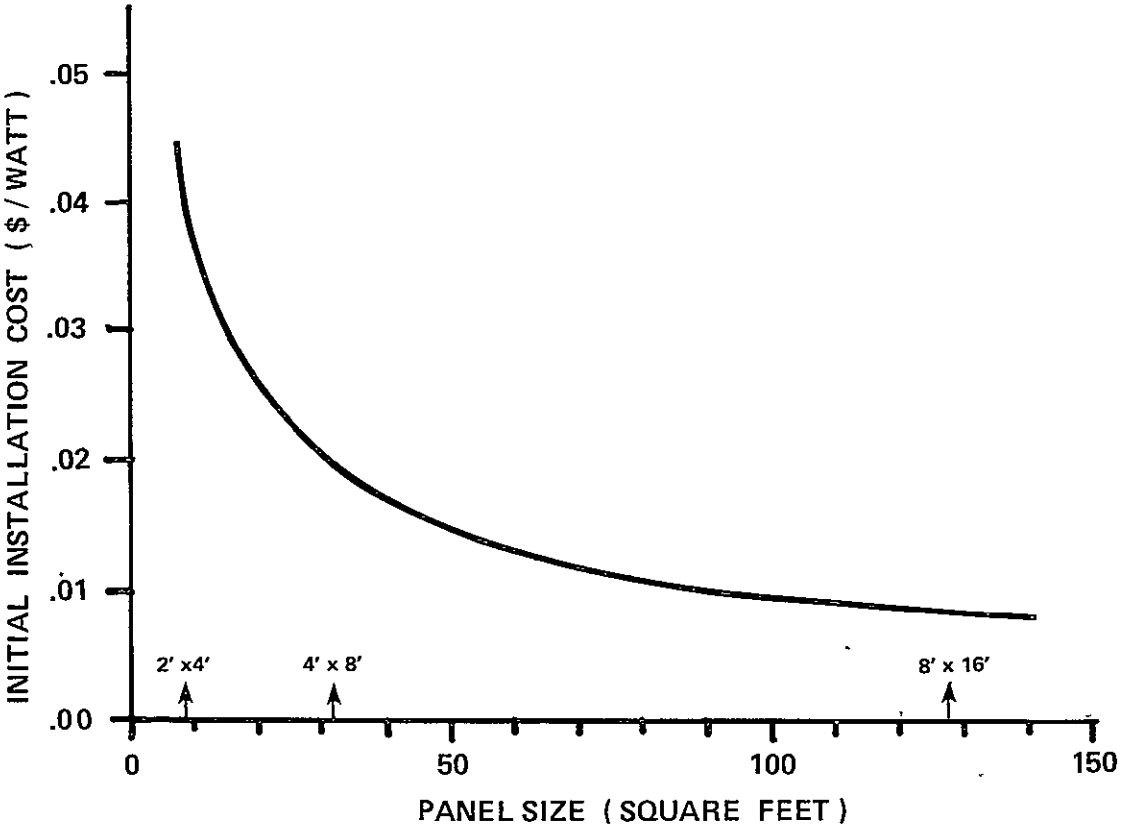


Figure 6 - 11 INITIAL INSTALLATION COST

disconnect, lift, and store the old panel in an empty carrier box. A new panel is lowered and installed in the same position as the old panel. The cycle of removing an old 8x16 foot panel and installing a new panel is estimated to take approximately 8 minutes. When the carrier box containing the old array panels is full and the new panel box is empty, the straddle carrier returns to the air-cushioned flat-bed truck. At the truck, the straddle carrier loads the box full of old array panels onto the truck, picks up a box of new panels, and returns to the array to continue replacement operations.

The estimated cost of replacing the 20,000,000 square feet of old panels and installing new panels is $1,740,000 (1975 dollars). Included in this cost are the overhead costs of two of the straddle carriers used during the construction period. With two straddle carriers used, six years would be required to replace all of the 8x16 foot panels.

Selective Replacement of Panels. As a part of the ongoing operation of the power plant, the performance of all array sections are continuously monitored as described in Section 6.3. As the performance falls to a predetermined level, certain panels are identified as requiring replacement. These would likely be distributed in a random fashion throughout the array field. The locations of these identified panels are assumed to be listed by operations personnel before the maintenance crews proceed with replacement.

The straddle carriers would be scheduled to proceed along each array structure and replace entire 8x16 foot array panels containing failed 4x8 foot modules which have been designated for removal. With the exception of selectivity, the operations involved in random panel replacement are similar to those of systematically replacing all the old panels as described in the previous section. The cycle time of 8 minutes in the previous case, however, is assumed to increase to 15 minutes per 8x16 foot panel. This includes added allowances for starting and stopping the operations and travel of the carrier between failed panel

locations. The cost of replacing an 8x16 foot panel is estimated at $21.00. This cost includes the amortization of a straddle carrier's overhaul cost and its operation and maintenance cost. One straddle carrier with a crew of four people can replace approximately 8,000 8x16 foot panels per year.

For larger plants, the same procedures would be used. For smaller plants (e.g., 10 MW), fewer installation and maintenance personnel would be needed and the procedures and panel size would have to be reevaluated to optimize costs.

6.3 FAILURE SCENARIOS

During the life of the solar power plant, a percentage of modules can be expected to fail in one of several modes. While some failures can be tolerated, certain abnormal conditions will lead to economically unacceptable losses in plant capacity, or present safety hazards to plant personnel and equipment.

6.3.1 Failure Rates and Categories

Failure rates and mechanisms for large, terrestrial photovoltaic modules in a central plant are not well defined at this time. The assumptions used in this study are presented below.

Failure Rates. Based on preliminary analyses conducted by the Jet Propulsion Laboratory, it is expected that failure rates can be divided into three time frames as follows:

- Infant mortality period
- Service period
- Failure period

During the infant mortality period, it is anticipated that approximately 5 percent of all modules will fail within 6 months of their initial installation.

During service life (between 6 months and 15 years after initial installation), modules will fail at a rate of approximately 2 percent per year.

Approximately 15 years after initial installation the failure rate will begin to increase exponentially, with 60 percent of all modules having failed by the end of 20 years. As discussed in the preceding section, there will be a scheduled replacement of all panels to extend the useful life of the plant.

Failure Categories. Module failures which affect the operation of the solar power system are categorized as follows:

- Complete module open circuit
- Solar cell interconnection open circuit

- Ground fault

The complete open circuit failure of any module will result in the loss of power from all modules connected in series with the failed unit. Module open circuit failures may occur as the result of connector failure, failure of the module power lead joint, or other types of internal failures.

Individual solar cell failures, in the form of cracked cells or broken intercell connections, will result from thermal cycling and other physical causes. Corrosion of cell interconnections can result from water vapor penetrating a module's encapsulant and condensing on the intercell connections. Modules will consist of parallel connected series strings of individual solar cells. Individual solar cell or intercell connection failures will result in the loss of the series string in which the failure occurs.

Under normal conditions, all electrical conductors on the array structure which operate at potentials other than ground will be insulated from the array framework, as well as all other possible contact with the station ground. Depending on the method of converter grounding, failure of this insulation (i.e., module, module connector, or wiring) can pose a safety hazard to plant personnel and/or station equipment. In an ungrounded dc system a single ground fault does not create a short circuit condition, and therefore does not require immediate protective action, nor

does it affect system operation. However, plant personnel, especially maintenance crews, could be exposed to dangerous potentials by simultaneously contacting both the array structure and either polarity of the dc bus. In a grounded dc system, any ground fault creates a short circuit condition which affects system operation.

6.3.2 Failure Detection

The detection of module related failures which significantly affect either system operation, plant energy output, or equipment and personnel safety involves first determining the existence of an abnormal condition, and then locating the cause.

Module Open Circuit Failure. As discussed, the complete open circuit failure of a module results in the loss of all modules in series with the failed unit. For the baseline case in this study (two module strings per array, see Figure 5-7), half the power from the array is lost. Such failures can be detected by monitoring the current level at the array terminals, and comparing each array current magnitude with the average value of several arrays in the area.

Direct current sensors, with ranges of up to 1000 amperes, can be provided for this purpose at a cost of about $275 each (1975 dollars). These current sensors resemble "window-type" ac current transformers in that they provide complete isolation

between the current carrying conductor and the output signal. The sensor's output is a linear 0-5 V dc signal, and accuracy is ±1% of full scale.

It is assumed that the plant design includes a central control room and a data link to each of the converters in the array field. This link provides for control of the converter and for monitoring the operation of the converter. Assuming further that this system contains an analog to digital converter for some of the converter data (e.g., ac voltage, power factor), only additional multiplexer channels need be added to accommodate monitoring the current from arrays. This can be accomplished at a cost of about $50 per channel (1975 dollars) for a flying capacitor type scanner. In operation, the current sensor outputs would be remotely scanned. The data would then be processed by the central computer, and a list of out-of-tolerance readings compiled.

In the baseline system design, six series module strings (three arrays) are paralleled in the field via a tapered bus and connected to the converter dc input by a single two-conductor cable. Locating the current sensors on these cables, at the converter, eliminates the need for long wires for analog signal transmission between the sensors and the multiplexer. Thus, the total (uninstalled) cost per data point is on the order of $325, or about $0.0009 per watt.

The total current at the design point for the six parallel strings is approximately 300 amperes. Since an open circuit failure would reduce the current from 300 amperes to 250 amperes, a change of 16.7 percent, the failure should be easily detectable. A maintenance crew could then be dispatched to the out-of-tolerance array wiring group to locate, and possibly repair, the failure. The failed string can be quickly identified in the field by the use of a portable clamp on type dc current sensor. The maintenance crew would monitor each string in the out-of-tolerance wiring group, until a string with zero current flow is located, indicating the failed string. Pinpointing the exact location of the failed module in the string can be accomplished using equipment similar to commercially available cable tracing and underground fault locating equipment. This equipment consists of a portable high impedance audio frequency signal generator (transmitter) and an inductive coil "probe" connected to a portable audio amplifier (receiver). To locate the failed module the following procedure is followed:

- The failed string is isolated from the dc system via disconnect switches, if provided, or by disconnecting the module connectors on the first and last modules in the string. This operation is greatly facilitated by the use of quick disconnect module connectors, discussed in Section 5.1.2. However, with this latter method, a zero current condition must be verified as the connectors are not rated for load-break operation.

- The transmitter output is connected between the array structure (ground) and either polarity of the failed string.

- Using the receiver, a member of the maintenance crew follows the transmitter's signal through the string by placing the inductive probe of the receiver in close proximity to each module. The weak electromagnetic radiation produced by the applied transmitter signal

will be detected at each module in the string that is electrically connected to the transmitter.

- The point at which the signal can no longer be detected indicates the location of the open circuit failure.

Intercell Connection Failures. Modules are composed of a number of parallel strings of series-connected solar cells. This is done to provide the desired module voltage and current levels, to increase module reliability, and to limit the effects of "hot spot" cell heating in the event of an individual cell failure (Ref. 19).

For example, using 3 inch diameter solar cells, the 4x8 foot module of the baseline design would be composed of about 35 parallel strings of 14 series cells per string (8.4 volts open circuit). This assumes a 1 inch border and 0.05 inch between cells. For a 1500 volt system, 178 modules would be connected in series. Thus each string has 35 cells in parallel in 178 series blocks. A string of this design would be virtually unaffected by loss of a single cell or intercell connection failure. The loss in generating capacity is essentially limited to the loss of power from 14 cells out of 87,220 in the affected string (e.g., 0.016%). The limited effect of these type of failures on array performance makes their detection and location extremely difficult.

One possible method of detecting this type of failure involves the use of an infrared camera to detect temperature differences

between operating and non-operating cells. For the module design postulated (i.e., 35 parallel and 14 series cells), loss of one series string of cells would result in a 3 percent increase in current through the remaining 34 strings. It is anticipated that this will not reverse bias the operating cells or cause a temperature rise. Assuming that the absorbed solar energy which is not removed as electrical energy is convected and radiated away in the form of thermal energy, indicates that a temperature rise might be expected for the non-operating string of cells. There will be critical module sizes and cell configurations in which the above effect and "hot-spot" effects result in the same temperatures for both operating and non-operating cells. If such points are avoided in module design, measurable temperature differences should exist for non-operating cells. The string of non-operating cells would be either hotter or colder than adjacent strings, depending on module design and which effect predominates.

Detection of such temperature differences could be accomplished by any one of several infrared cameras such as are commercially available from AGA Thermovision, Barnes Engineering, and others. For instance, a device such as AGA Thermovision's model 750 could be truck mounted and driven slowly through the array field. This device can detect temperature differences as small as 0.2°C on a 30°C surface. Temperature is displaced as a color difference on a CRT monitor. The cost of this device and its accessories is about $45,000 (1975 dollars). In evaluating this detection

system, the costs of maintenance personnel labor, liquid nitrogen (needed to operate the detector), and a truck must be added to the cost of the device itself.

The problem of interference from solar infrared reflections from the surface of the module may be ameliorated by adding an IR filter to exclude radiation outside of the detector's 2 to 5.6 μm spectral range and by aiming the camera to avoid reflections. Also, it is anticipated that the normal thermal gradients on the module (e.g., cooler edges) will not greatly interfere with the detection of failed strings of cells.

This general method was previously used in testing arrays for space applications (Ref. 20). Results under solar similator testing were poor owing to multiple IR reflections and variations in adhesive thickness. Satisfactory results were obtained by applying a reverse bias to heat the cells. Should testing under solar illumination prove infeasible, it may be possible to employ this latter method.

A second possible method of detecting open strings within a module consists of measuring the I-V curve for each module. This method involves comparing a module against a standard (or its neighbors). Portable equipment needed includes a programmable variable resistance load, a standard cell to measure solar insolation, one or more thermocouples to measure module temperature, and a truck to carry the equipment. This labor-

intensive method involves disconnecting each module, connecting it to the portable test equipment, and measuring its characteristics.

The estimated cost of the test equipment (including the truck) is $4,000. For the baseline design, the testing of all modules mounted on a single array structure is estimated to require 21 hours. The testing cost per array structure is $1,100, based on a 3 man crew and a maintenance labor cost of $14.00 per hour direct cost with 25 percent for distributables. All costs are in 1975 dollars.

Testing of all modules in the 200 MW baseline design plant (624,000 modules on 1667 array structures) could be accomplished at a cost of $\$1.83 \times 10^6$, and would require 35,000 hours, or about 4,375 eight-hour shifts. A single test crew and truck working 5 days a week, 52 weeks a year, would require 16.8 years to complete a single test sequence. Twenty crews working simultaneously could test all of the modules in a 10 month period, and would require a capital investment of $80,000 for the twenty test vehicles.

An alternative to testing all modules would be to test each module string, with individual modules being tested only on those strings which show unacceptable performance. However, even with these procedures, it may be difficult to differentiate between expected degradation and failures.

Ground Fault. The nature and severity of a ground fault will depend on the method of system grounding and, in some cases, on the location of the fault within the system.

The operation of an ungrounded system is unaffected by the occurrence of any single ground fault. For this reason it is the preferred configuration from a converter design viewpoint, as discussed in Section 5.1.4. Detection and repair of ground faults is required, however, to prevent the occurence of two concurrent ground faults on the same converter bus, which would lead to equipment damage and possibly to a personnel hazard.

A ground fault on a normally grounded system will create a short circuit condition. All modules in the faulted string which are located between the normal system ground and the ground fault will be forced to operate into a short circuit, via the metal array framework.

Proper system design and insulation coordination should minimize the occurrence of ground faults. Therefore, remote detection and indication requirements can probably be limited to the monitoring of each converter bus. This can be accomplished at minimum cost via a resistor network, current relays, and the data acquisition system utilized for module open circuit detection.

A ground fault would be alarmed in the central control room whereupon the operator would dispatch a maintenance crew to the

affected power conditioning unit. The exact location of the fault could then be located utilizing equipment and techniques similar to those described for locating module open circuits.

6.3.3 Replacement Economics

After a failure is detected, it may not be repaired unless it is economical to do so. This point is addressed below for the types of failure evaluated herein.

Module Open Circuit Failure. If a module fails open, power is lost from the entire string of modules. This amounts to 60 kW in the baseline case discussed in Section 5.2. Thus, on the average, the revenue from 300 kWh is lost each day. For energy values of 25 to 65 mills per kWh, this corresponds to $7.50 to $19.50 per day, respectively. The cost to replace the panel containing the defective module is estimated to average $21. In addition, the cost of the panel must be included. This cost is assumed to be $0.50 per watt or $640 per 8x16 foot panel, assuming no scrap value for three good modules in the panel. Thus, the replacement is paid for in 34 to 88 days, depending on the value of the energy sold.

Analysis of the data in preceding sections of this report shows that this number-of-days-to-breakeven is inversely proportional to the selling price of energy and system voltage, and is directly proportional to module voltage. Additionally, the days-

to-breakeven vary approximately as the inverse of panel size below 25 square feet and about to a -0.2 power above that size, assuming that replacement costs vary in proportion to installation cost. Thus, the longest payback time is for a system with a low system voltage, small modules, a high module voltage and a low value for the energy sold. For the range of system parameters evaluated herein the worst case might be quantified as a 1500 volt system of 2'x4' modules having an open circuit voltage of 16 volts and a value of energy sold at 25 mills per kWh. These parameters indicate a breakeven time of about 160 days. Thus it may be concluded that unless the plant is within half a year of a scheduled replacement of all panels, individual panels should be replaced as they fail.

Intercell Connection Failures. Intercell connection failures on the larger panel (and module) sizes discussed in the preceding section (Section 6.3.2) will not result in a significant reduction of power output from the affected array. Thus, it is not economical to replace the panel for this type of failure.

Occurrence or accumulation of multiple failures of this type in a single module may eventually lead to power losses that are significant. In this instance, such failures would be detectable by the current-monitoring scheme previously described. Alternatively, the resultant hot-spot temperatures at this stage of multiple failure may become readily detectable by means of the infrared camera, or even with less sophisticated equipment if

there are enough open cell strings. At this point, the economic logic used in discussions of module open circuit failures would apply and the defective modules should be replaced.

Ground Faults. The first ground fault on a segment of the dc wiring system may be a precursor of a second fault. Two coincident faults can damage the equipment and expose personnel to an unnecessary safety hazard. For this reason, ground faults should be repaired when they occur.

6.4 WARRANTEES

In the engineering and construction of conventional steam-electric power plants, warranteee provisions are generally included in the terms of the purchase orders for equipment used. They cover the integrity of the equipment and protect the owner against defects in material and workmanship for a specified period of time, usually one year following the date of commercial operation of the entire power plant. In many instances warrantees are negotiated. For example, some manufacturers limit their liability only to the replacement of parts or exclude corrosion of metal parts from coverage of the agreement. Manufacturers of smaller items tend to offer a warrantee starting at the date of arrival of their equipment at the jobsite.

For large pieces of equipment which may have been purchased under a performance specification, the owner may withhold 5 to 10% of

the total payment until acceptance tests are completed. Depending upon the results of these standardized performance tests, the vendor may have the final payment adjusted by either an incentive or a penalty clause in the contract.

An equipment manufacturer may recommend certain procedures for the operation of his product and may also have specific recommendations on the frequency and extent of maintenance work. Both of these considerations bear upon the useful life of the product and the manufacturer's risk of entering into a long term warrantee. While scheduled maintenance is performed on a more uniform basis in the power field than in other industries expecting much shorter economic payback periods, it is still difficult to get an equipment manufacturer to make a long term commitment on his product. This can be linked to both the variability of operating and maintenance practices and manufacturer's hesitancy to become responsible for consequential damages (e.g., lost power revenues) due to failures statistically expected on the near side of a normal distribution curve.

Because of this practice of not extending equipment warrantees into a significant portion of a power plant's useful life of 20-30 years, the owner through his agent, the architect/engineer, is generally conservative in design philosophy. He is also cautious in selecting who is invited to bid on equipment in a power plant. In the power industry, most utilities rely upon manufacturers' experience and reputation.

Section 7

CONCLUSIONS

Major conclusions derived from this engineering study of the module/array interface from the viewpoint of an equipment installer and maintainer are presented in this section.

The conceptual structures in this study are able to use readily available steel and glass materials even when using maximum snow, wind, and seismic loads predicted for the continental U.S. (excluding Alaska).

For the baseline plant design in the Phoenix area, wind forces dominate the array structural design. Wind or snow loads dominate at other site locations, but seismic forces do not dominate.

Wind forces can produce net uplift on the array structures and must be resisted by dead weight or foundation designs.

The interaction of glass modules and their steel frames must be carefully analyzed for a prototype in order to prove that adequate edge support is provided for the glass. If the metal frame is too flexible, then glass stresses can exceed allowable limits.

The present study focuses mainly on the module/array interface without detailed consideration of the array framework. For the large array systems evaluated herein, the division of the array into two structural groups (i.e., array framework and panel framework) is consistent with the logical division of fabrication responsibilities. However, further optimization of total plant design and life cycle cost may be derived from future structural evaluations of the array in its entirety (i.e., from the soil and foundation through the module).

Of the several types of intermodule connection schemes evaluated, the quick-disconnect type is preferred for reasons of cost and ease of installation. High dc system voltage, current rating, and exposure to the weather do not appear to present any major problems for this type of connector.

Intermodule connector costs generally decrease with increasing module size. Connector costs for a 4x8 foot module with an 8 volt open circuit voltage are estimated to contribute $0.01 per watt to the plant cost.

For purposes of this study, module currents were limited to less than 100 amperes in detailed evaluations in order to ameliorate wiring difficulty within the module. The preferred cell configuration postulated for the 4x8 foot module has a short circuit current on the order of 50 amperes.

Interarray wiring costs decrease with increasing module size up to about 50 square feet per module and then level off. These costs also decrease with decreasing module voltage.

For the designs postulated herein, interarray wiring cost and converter costs decrease with increasing dc system voltage. Wiring costs vary approximately as voltage to the -0.8 power and converter costs (above 1000 volts) vary as voltage to the -0.2 power. For a 2500 volt dc system, converters costs contribute on the order of $0.065/watt to the plant cost; interarray wiring contributes less than one twentieth of that amount.

For reasons of converter cost, the dc system voltage should be at least 1200 volts.

Preliminary analyses, based on available data on plant design, indicate that modules may be exposed to voltage transients of about 3 per unit (e.g., a 2500 volt dc system may be exposed to voltage transients on the order of 7500 volts).

Final selection of a dc system voltage and module voltage withstand requirements will depend on analyses of module cost versus voltage withstand capability and plant design features such as the type of converter used and the design of the lightning protection system.

Within the bounds of the study, panel installation costs decrease with increasing panel size, varying approximately as panel size to the -2/3 power. Initial installation of 8x16 foot panels are estimated to contribute $0.009 per watt to the plant costs. Panels much larger than 8 feet in width become increasingly difficult to ship.

Minimizing installation costs indicates that large panel sizes (e.g., 8x16 foot) should be selected. Available data on module fabrication technology indicate that sizes smaller than this are being considered in JPL's Automated Array Assembly studies. Both of these factors can be accommodated by factory assembly of several small modules into a large panel for shipping and field installation (e.g., assembly of four 4x8 foot modules to constitute an 8x16 foot panel).

A preliminary analysis, based on available data, has shown array cleaning by means of an automated washing unit to be economically justified in instances where energy is sold for more than 65 mills/kWh or where energy is sold for more than 25 mills/kWh and power loss due to dirt accumulation exceeds 8 percent.

A preliminary analysis of the economics indicates that, for the design postulated herein, completely failed modules should be replaced as such failures occur. Replacement of modules with one or two open strings of cells is not economically justified.

Ground faults should be repaired as they occur to prevent equipment damage.

Failure of a single intercell connection in high-current, low-voltage module designs produces relatively little effect on system performance. Thus, for designs where this type of failure is difficult to detect, the need to detect and repair such failures becomes less significant.

Section 8

RECOMMENDATIONS

The recommendations presented in this section are offered for the purpose of assisting JPL in accomplishing the goals of the LSSA program.

Wind effects on a large field of arrays should be investigated in order to provide more detail on drag and lift forces. This investigation should include the effects of wind turbulence around arrays in a field of array structures. The results of such investigations will enable more accurate structural design calculations to be made, as well as enable more accurate calculations of module temperature and thermal gradients.

Estimates of module cost as a function of size and voltage withstand capability should be developed and combined with the data presented in this report in order to develop module and system designs that minimize plant life-cycle costs.

Many of the module's electrical characteristics are governed by plant design features. In particular, further analyses of converter and lightning protection systems should be performed before module insulation levels are set. Also, the interarray dc wiring system should be further analyzed with respect to initial cost and I^2R losses before array configurations and module

current levels are selected. Such studies would aid in designing modules which minimize total plant life-cycle costs.

Glass modules were selected as the most likely candidate for large, terrestrial arrays. Depending on the likelihood of their use, the structural analyses described herein should be expanded to incorporate other structural concepts, such as plastic or aluminum module substrates with polymeric covers.

As design concepts and module sizes are developed, the present finite-element computer analyses should be iterated to optimize selection of framing member sizes and, perhaps, further extended to evaluate the panel members in conjunction with the entire array structural system in order to utilize any synergistic effects which may be present.

Structural analyses of the module design concepts presented herein should be expanded to include other modules shapes, frame configurations, and framing materials in order to allow selection of designs which minimize costs. Further, selected module designs should be computer analyzed to determine their natural frequencies, with the results related to possible amplification by site seismic and wind spectra.

The preliminary analyses of module failure detection and replacement should be expanded to reanalyze the problem with

module design, failure rates, types of failures, and plant size as parameters.

Section 9

NEW TECHNOLOGY

No reportable items of new technology have been identified by Bechtel during the conduct of this work.

REFERENCES

(1) Bechtel Corporation, Preliminary Report on a Conceptual Design of a Photovoltaic Central Station Power Plant, prepared for Spectrolab Inc., under Contract No. 66725, January 1976

(2) Energy Research and Development Administration, Review of World Experience And Properties Of Materials For Encapsulation Of Terrestrial Photovoltaic Arrays; Final Report, ERDA/JPL/954328-76/4, July 21, 1976

(3) E. B. Shand, Glass Engineering Handbook, Second Edition 1958, McGraw-Hill Book Company

(4) American Institute of Steel Construction, Manual of Steel Construction, 7th Edition, 1970

(5) Pittsburg Plate Glass Company, Wind Load Performance, Technical Service Report No. 101A

(6) American National Standards Institute, Building Code Requirements For Minimum Design Loads IN Buildings And Other Structures, ANSI A58.1-1972

(7) U.S. National Oceanic and Atmospheric Administration, Climates Of The States; Volume 2, Western States, 1974

(8) Weather Trends Inc., Climatological Atlas Of The Continental United States: Precipitation, New York 1966

(9) S. C. Hollister, "The Engineering Interpretation Of Weather Bureau Records For Wind Loading On Structures", National Building Service, Report BSS30, November 1970

(10) H. C. S. Thom, "New Distribution Of Extreme Winds In The United States", Journal of the ASCE, Vol. 94, No. ST7, July 1968

(11) International Conference of Building Officials, Uniform Building Code, 1976 Edition

(12) Timoshenko & Woinowsky-Krieger, Theory Of Plates And Shells, New York, McGraw-Hill, 1959

(13) A. H. Cantu, Test Program on Low-Cost Connectors for Solar-Array Modules, LSSA Task Report 5101-20, Jet Propulsion Laboratory, February 28, 1977

(14) General Electric Company, "On the Nature of Lightning", Transmission, Vol. 3, No. 2, October 1971, pp. 2-6

(15) Westinghouse Electric Corporation, "Lightning Phenomenon", Chapter One, Surge Protection of Power Systems, September 1971, pp. 1-11

(16) J. L. Marshal, Lightning Protection, John Wiley and Sons, 1973

(17) IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems, Std 142-1972, New York, Institute of Electrical and Electronics Engineers, Inc., 1972, p. 87

(18) R. L. Cummerow, "Photovoltaic Effect in P-N Junctions", Physical Review, Vol. 95, No. 1, July 1954

(19) R. G. Ross, Jr., "Interface Design Considerations for Terrestrial Solar Cell Modules", Proceedings of the IEEE Photovoltaic Specialists Conference-1976, Baton Rouge LA, pp. 801-806

(20) R. R. Prudhomme, D. Waddington and H. Over, "Infrared Testing of Solar Cell Arrays", presented at the National Fall Conference of the American Society for Nondestructive Testing, October 1971