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Photovoltaics Program
Program Analysis and Integration Center

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Sensitivities of Projected 1990 Photovoltaic System Costs to Major System Cost Drivers

L.W. Zimmerman
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December 15, 1984

Prepared for
U.S. Department of Energy
Through an Agreement with
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ABSTRACT

This report examines the sensitivity of projected 1990 photovoltaic (PV) system costs to major system cost drivers, including (1) module costs and module efficiencies, (2) area-related balance-of-system (BOS) costs, (3) inverter costs and efficiencies, and (4) module marketing and distribution markups and system integration fees. The report reviews recent PV system cost experiences, illustrating the high costs of electricity from the systems. Based on a review of selected PV engineering literature, 1990 system costs are then projected for five classes of PV systems, including four ground-mounted 5-MW_p systems and one residential 5-kW_p system. System cost projections are derived by first projecting costs and efficiencies for all subsystems and components. Sensitivity analyses reveal that reductions in module cost (including marketing markups) and engineering and system integration fees seem to have the greatest potential for contributing to system cost reduction. Although module cost is clearly the prime candidate for fruitful PV research and development activities, engineering and system integration fees seem to be more amenable to reduction through appropriate choice of system size and market strategy. Inverter costs are not as significant to total system costs as are other cost categories. But increases in inverter as well as module efficiency yield significant benefits, especially for systems with high area-related costs.

FOREWORD

This report documents work done by the Photovoltaics Program Analysis and Integration Center at the Jet Propulsion Laboratory during 1983 in support of the U.S. Department of Energy (DOE) National Photovoltaics Program. It examines the sensitivity of projected 1990 costs of grid-interconnected photovoltaic (PV) systems to major system cost drivers. DOE supports a sizable research and development program specifically aimed at reducing the costs of PV systems by or before 1990; continued examination of the importance of major subsystem costs and efficiencies to projected 1990 PV system costs is an essential element of informed, responsive PV program management and resource allocation.

To meet its purpose, it is necessary that this report project total PV system costs to 1990. However, these projections should not be interpreted as PV system cost predictions, because important, unresolved uncertainties about PV system costs and performance do not allow such predictions with confidence. As the report reveals, the uncertainty bounds of the cost projections are large, as expected in any research and development program. The report's projections reflect only present knowledge of 1990 PV technology, and their only purpose is to serve as a baseline for sensitivity analyses. These projections and sensitivities reflect the views of the author and not necessarily those of DOE.

CONTENTS

Figures

Tables

PART ONE

Executive Summary

EXECUTIVE SUMMARY

This report examines the sensitivity of projected 1990 photovoltaic (PV) system costs to major system cost drivers, including (1) module costs and module efficiencies, (2) area-related balance-of-system (BOS) costs, (3) inverter costs and efficiencies, and (4) module marketing and distribution markups and system integration fees. Because the primary limitation to widespread use of photovoltaic systems is their present high cost, and because the federal government invests about $50 million annually in research and development (R&D) aimed at PV system and component cost reduction, detailed understanding of the likely effects of technology improvements and other system or subsystem design changes or approaches on installed PV costs is valuable. Such information is useful in guiding both federal and private R&D in a search for competitive bulk-power PV systems.

The report begins with a brief review of recent PV system cost experience. As expected, present systems are expensive and do not generate power at costs competitive with bulk-power sources (e.g., oil, gas, nuclear, and coal). Recently installed grid-connected systems range in cost from as low as \$10/$W_p$dc to as high as \$90/$W_p$dc. Many of these systems were highly instrumented, experimental, first-generation designs for which system performance was the key attribute and costs were a secondary consideration. However, even the most recent and least expensive privately funded systems (\$11-\$13/W_p) produce electricity at costs four to eight times those of U.S. electric utilities.

Section III reviews selected engineering literature for the purpose of projecting 1990 PV system costs. All cost projections, including these, contain inherent uncertainties. No one can accurately and completely foresee technological progress. Thus, the projections contained herein are simply a reflection of the present understanding of the most likely path of future technical progress in PV systems as embodied in PV engineering literature. Unforeseen or proprietary advances are necessarily excluded from the projections. For this reason, module cost projections have been limited to crystalline silicon materials. Technical uncertainties about other PV materials are believed to be substantially greater than for crystalline silicon.

Based on the review of selected PV engineering literature, 1990 system costs are projected for five classes of PV systems, including four ground-mounted 5-MW_p systems and one residential 5-kW_p system. These systems are believed to represent adequately the types of systems that are or will become available in the early 1990's. The ground-mounted systems include three flat-plate systems (fixed, single-axis tracking and two-axis tracking, respectively) and one concentrator system. In all cases, the cell technology assumed is crystalline silicon. All systems are grid-connected without energy storage.

System cost projections are derived by first projecting costs and efficiencies for all subsystems and components. Three points on the cost probability distribution are projected for each subsystem or component: the 25%, 50%, and 75% cumulative probability points. That is, for each subsystem or component, the costs or efficiencies that are believed to have a 25%, 50%, and 75% chance, respectively, of being higher than the 1990 actual costs or efficiencies for that subsystem or component, are projected. Baseline system costs are then projected by adding the 50th percentile projections together. In Section VI the ranges established by the 25% and 75% points are discussed.

Baseline 1990 PV system cost projections are shown in Table E-1. Note that a site-specific ac system rating that partially corrects for insolation and temperature differences across sites has been adopted. Thus, different system costs are projected for three cities (Phoenix, Miami, and Boston) to reflect different-sized array fields necessary to achieve equivalent peak output at these sites.

As noted above, these projections should not be interpreted as PV system cost predictions. Furthermore, such system cost projections are not an appropriate basis upon which to compare different PV system designs because important system costs and benefits are omitted from a comparison based on

Table E-1. Installed 1990 Photovoltaic System Cost Projections, 1982 $

System	Projected System Cost, $\$/W_pac$		
	Phoenix	Miami	Boston
Ground-Mounted ($5MW_pac$)[a]			
Flat-Plate			
Fixed	2.45	2.78	3.13
Single-Axis Tracking	2.62	2.98	3.35
Two-Axis Tracking	3.14	3.58	4.04
Concentrator			
Planar Silicon	3.80	4.76	5.50
Roof-Mounted ($5kW_pac$)			
Tract House	2.83	3.17	3.52
Custom House	4.22	4.73	5.26

[a]These are site-specific peak power ratings based on the Electric Power Research Institute's nominal peak operating conditions (NPOC) rating method.

costs per rated peak watt, regardless of how systems are rated. For example, sun-tracking systems will collect and produce as much as 40% more energy than fixed-tilt systems with equal ratings. A more appropriate basis for comparing systems is levelized bus-bar energy cost as illustrated in Appendix A, although even this method does not fully capture all potential system discriminators (e.g., differences in time-of-day or seasonal valuations of electricity).

Section IV examines sensitivities to major system cost drivers in two ways. First, by assuming that the costs of all subsystems move together (are perfectly dependent), a range of projected system costs can be generated. For this case, the total of the subsystem and component costs is calculated at the 25th percentile and 75th percentile, respectively. The resulting system cost range reflects much more than a 50% confidence interval because technological progress is likely to occur somewhat independently among subsystems. A second approach to system cost sensitivities is also presented. In this case, all subsystem and component costs but one are held at their baseline value while the effects of changes in costs of one major subsystem on total system costs are examined. In this manner, the sensitivity of projected system costs to each major cost driver is isolated.

In addition to technical uncertainties, market size can have a major impact on PV system, subsystem, and component costs. To isolate the technological uncertainties as much as possible, all cost projections in this report are made on the basis of an assumed world market for grid-connected photovoltaic systems of 100 to 200 MW_p annually by 1990, allowing realization of significant economies of scale.

The sensitivity analyses of Section IV reveal that reductions in module cost (including marketing markups), and engineering and system integration fees seem to have the greatest potential for contributing to system cost reduction. These costs not only represent a significant proportion of total system costs, but also are highly uncertain. They are also partially dependent upon market structure and size. While module cost is clearly the prime candidate for fruitful PV research and development activities, engineering and system integration fees seem to be more amenable to reduction through appropriate choice of system size and market strategy.

Area-related costs are also a significant portion of total costs, but the range of potential area-related costs is not of the same magnitude as module costs or engineering and integration fees. Inverter costs are not as significant to total system costs as are other cost categories. But increases in inverter as well as module efficiency yield significant benefits, especially for systems with high area-related costs.

PART TWO

Probable Effects of Technology Improvements, Design Changes and Approaches

SECTION I

INTRODUCTION

This report examines the sensitivity of projected 1990 photovoltaic (PV) system costs to major system cost drivers including (1) module costs and module efficiencies, (2) area-related balance-of-system (BOS) costs, (3) inverter costs and efficiencies, and (4) module marketing and distribution markups and system integration fees. Because the primary limitation to widespread use of photovoltaic systems is their present high cost, and because the federal government invests about $50 million annually in research and development (R&D) aimed at system and component cost reduction, an understanding of the probable effects of technology improvements and other system or subsystem design changes or approaches on installed PV costs would be useful in guiding both federal and private R&D in developing competitive bulk-power PV systems.

The report begins with a brief review of recent PV system cost experience. As expected, present systems are expensive and do not generate power at costs competitive with bulk-power sources (e.g., oil, gas, nuclear, and coal). Section III reviews selected engineering literature for the purpose of projecting 1990 PV system costs. All cost projections, including these, necessarily contain uncertainties. No one can accurately and completely foresee technological progress. Thus, the projections herein simply reflect present understanding of the most likely path of future technical progress in PV systems as embodied in the PV engineering literature. Unforeseen or proprietary advances are necessarily excluded from the projections. For this reason, module cost projections have been limited to those using crystalline silicon materials. Technical uncertainties concerning other PV materials are substantially greater than for crystalline silicon.

Based on the review of selected PV engineering literature, baseline 1990 system costs are projected for five classes of PV systems, including four ground-mounted 5-MW_p systems and one residential 5-kW_p system. These are believed to represent adequately the types that are or will become available in the early 1990's. The ground-mounted systems include three flat-plate systems (fixed, one-axis tracking and two-axis tracking, respectively) and one concentrator system. In all cases, the cell technology assumed is crystalline silicon. All systems are grid-connected without energy storage.

System cost projections are derived by first projecting costs and efficiencies for all subsystems and components. Three points on the cost probability distribution are projected for each subsystem or component: the 25%, 50%, and 75% cumulative probability points. That is, for each subsystem or component, the projected costs or efficiencies that are believed to have a 25%, 50%, and 75% chance, respectively, of being higher than the 1990[1]

[1]Although we refer to cost projections for 1990, this should be interpreted throughout the report as being within the period 1990-1992.

actual costs or efficiencies for that subsystem or component, are projected. Baseline system costs are then projected by adding the 50th percentile projections together.

Sensitivities to major cost drivers are examined in two ways. First, by assuming that the costs of all subsystems move together (are perfectly interdependent), a range of projected system costs can be generated. For this case, we simply total the subsystem and component costs at the 25th and 75th percentiles, respectively. The resulting system cost range reflects much more than a 50% confidence interval, given that technological progress is likely to occur somewhat independently among subsystems. A second approach to system cost sensitivities is also presented: in this case, all subsystem costs but one are held at their baseline value while the effects of changes in costs of one major subsystem on total system costs are examined. Thus, the sensitivity of projected system costs to each major cost driver is isolated.

In addition to technical uncertainties, market size can have a major effect on PV system, subsystem, and component costs. To isolate the technological uncertainties as much as possible, all cost projections in this report are made on the basis of an assumed world market for grid-connected photovoltaic systems of 100 to 200 MW_p annually by 1990, allowing realization of significant economies of scale. (Currently, the U.S. PV industry markets about 15 MW_p annually.)

Appendix A presents and exercises a method of calculating the real busbar energy costs (1982 $/kWh) of electricity that would be generated by PV plants having projected costs based upon this report's 1990 baseline.

Appendix B presents the conditions under which modules are rated with respect to their direct-current outputs for four distinct module-rating schemes.

SECTION II

RECENT PHOTOVOLTAIC SYSTEM COST EXPERIENCE

A. INTRODUCTION

This section reviews briefly the cost experiences of photovoltaic systems recently constructed in the United States, with emphasis on larger and grid-connected systems. The first section reviews utility-scale experimental systems, followed by brief reviews of intermediate-sized and residential-sized systems.

B. CENTRAL POWER STATION APPLICATIONS

One of the largest installed photovoltaic systems is the 1-MW ARCO Solar, Inc., installation at Hesperia, California. This field has two-axis tracking structures with flat-plate PV panels mounted on torque tubes. The tracking structure uses an ARCO heliostat originally designed for a solar-thermal system. The system has three dc/ac inverters, a 1-MW_p Garrett AiResearch Manufacturing Co. unit and two 500-kW_p Helionetics, Inc., DECC inverters. This provides significant redundancy in power-conditioning capacity to improve overall system reliability. ARCO's system was privately financed, and system cost information is not available. The system supplies electricity to the Southern California Edison Co.

In addition, ARCO is installing a larger (6-MW) PV system featuring a two-axis tracking structure with mirror-enhanced flat-plate panels at Carissa Plain, California. Again, complete system cost information has not been made public, although some details are known about the power conversion subsystem. ARCO has contracted with Helionetics for nine 750-kW inverters at a price of $0.35/W in current dollars. An additional $0.05/W is being charged by Helionetics to cover ac system integration and procurement.

Another 1.2 MW_pdc[2] field is under construction at the Sacramento Municipal Utility District (SMUD) Rancho Seco nuclear reactor site. The SMUD Phase I design is one-axis tracking, where the modules track from east to west, lying horizontally at solar noon. The PV inverter is a Windworks, Inc., fixed-voltage unit with a peak operating efficiency of 97%. The 1-MW field is the first phase of a planned 100-MW installation scheduled to be completed in 1993. Estimated Phase I system costs are given in Table 1.

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[2]Photovoltaic modules are rated by direct current (dc) output observed under a set of standard conditions (see Reference 1). At least three sets of ratings and associated standard conditions are in use: standard test conditions (STC); nominal operating conditions (NOC), and standard operating conditions (SOC). These conditions are shown in Table B-1, Appendix B. Ratings for PV systems often are quoted as simply the sum of the dc module ratings for the entire array field of the system, multiplied by the efficiency of the BOS to give an alternating current (ac) rating. This report adopts a different site-specific system rating scheme, discussed in III H 1.

Table 1. Cost Forecast for SMUD 1.2 MW_pdc (STC) (1.0 MW_pac) Phase I Photovoltaic System, 1983 $ x 1000

Description	Estimate as of June 1983[a], $	Implied Unit Cost
PV Panel Procurement (includes shipping)	7,167	\$4.95/$W_p$dc (STC) (modules f.o.b.)
PCU[b] Procurement (includes testing and circuit switchgear)	401	\$0.401/$W_p$ac
Array Field Construction	1,460	\$110/m^2
System Integration		33% of direct costs
A&E[c] Subcontract	1,933	
SMUD (through 9/85)	459	
Construction Contingency	400	
Operational Contingency	180	
Total	\$12,000	\$12/$W_p$ac

[a]SMUD Phase I Construction Readiness Review, June 1983.

[b]PCU = power conversion unit

[c]A&E = architectural and engineering

The second phase of the SMUD project, a 1-MW_pdc field, also is under contract. This field deploys 900 kW_p of ARCO modules at a cost slightly less than that of Phase I (\$4.84/W versus \$4.95/W) plus 100 kW_p of Solarex Corp. modules. The SMUD Phase II Toshiba inverter cost \$546,000, or \$0.68/Wac if the field is rated at 800 kW_pac.

C. INTERMEDIATE APPLICATIONS

Under the Federal Program Research and Development Announcement (PRDA) program, nine prototype PV systems ranging in size from 17.5 to 225 kW_pdc were installed across the country. Installed system costs varied from \$24/W_p to \$32/W_p for flat-plate systems and from \$18/W_p to \$68/W_p for concentrator systems (1983\$). An additional intermediate-sized concentrator system, the 350-kW Saudi Arabian Village Project, was installed in Egypt under the Soleras program, the project agreement for cooperation in the field of

Table 2. Installed Costs of Several Intermediate-Sized Photovoltaic Systems (Current $)

Project	Design Size, kW_p(dc)	Date of Initial Operation	Collector Cost $\$/W_p$dc	Area-Related BOS Cost, $\$/m^2$	Inverter Cost $\$/W_p$dc	Cost of Thermal Subsystems, $\$/W_p$dc	System Design & Engineering, % of Subtotal	Total System Cost, $\$W_p$dc
Flat-Plate Systems								
El Paso Electric UPS[a] El Paso, Texas	17.5	1/81	9.43	543	—	—	79	32.40
Battelle Installation[b] Albuquerque, New Mexico	30	1/83	7.61	146	0.60	—	N/A	N/A
Hughes Installation[c] Albuquerque, New Mexico	30	2/83	8.79	163	0.60	—	N/A	N/A
CDC Manufacturing[a] San Bernardino, California	35	1/82	13.63	501	1.71	—	51	30.28
Beverly High School[a] Beverly, Massachusettes	97	1/81	11.20	578	2.45	—	43	32.16
Lovington Shopping Ctr.[a] Lovington, New Mexico	104	3/81	11.01	376	2.61	—	49	29.53
Science and Art Ctr.[a] Oklahoma City, Oklahoma	135	2/82	13.08	715	0.50	—	24	24.11
Concentrator systems[d]								
DFW Airport[a] Dallas/Fort Worth, Texas	27	6/82	22.44	946	1.00	3.48	56	55.47
G. N. Wilcock Hospital[a] Lihue, Kauai, Hawaii	35	1/82	23.11	640	1.37	2.06	97	68.49
BDM Corp. Office[a] Albuquerque, New Mexico	47	5/82	8.96	229	0.87	1.17	166	38.37
Sky Harbor Airport[a] Phoenix, Arizona	225	6/82	10.69	210	0.98	—	35	18.37

[a] Reference 1

[b] Reference 2

[c] Reference 3

[d] Comparable data are not available for the 280-kW_pdc Soleras concentrator system installed in Saudi Arabia, which was first operated in March 1982. However, contract costs exceeded $25 million, implying system costs of at least $90/$W_p$dc.

solar energy between the United States and Saudi Arabia. These systems were generally characterized by high system costs. Two additional intermediate-sized flat-plate systems were recently installed to demonstrate low-cost array field designs, but system costs were raised by conservative installation contracts with local contractors and extensive oversight by both Hughes Aircraft Co. and Battelle Columbus Laboratories engineers. Table 2 summarizes the costs of these intermediate-sized systems.

D. RESIDENTIAL APPLICATIONS

Small photovoltaic systems are currently being marketed in remote areas of the United States where there is no electric utility grid economically available. These systems are frequently smaller than 500 W_p; most are mounted directly on roofs. Typical ARCO systems sold for between $\$10/W_p$ and $\$12/W_p$ in 1983 (with owner installation), which includes PV panels, a battery bank, and a regulator, but no inverter.[3] These systems are an economical source of electricity for any residence in the U.S. located more than a half mile from the electric grid because of the high cost of grid

Table 3. System Cost Experience for Publicly Funded Grid-Connected Photovoltaic Residences[a], Current $

Project	Nominal Array Output, kW_pdc	Completion Date	Total System Cost, $\$/W_p$dc
Carlisle Carlisle, Massachusetts	7.8	2/8	14
FSEC[b] Cape Canaveral, Florida	4.0	8/80	--
Hawaii Houses Hawaii	3.3	5/81	29
Long House Phoenix, Arizona	6.6	5/80	39
University of Texas Arlington, Texas	8.0	10/78	21

[a]Reference 4

[b]FSEC = Florida Solar Energy Commission

[3]Telephone conversation with Joel Davidson, author of The Solar Electric Home: A PV How-to-Handbook and an ARCO Solar distributor.

connection (residences closer to the grid may prefer PV systems if state tax incentives are available, as in California).

Currently, there are only a few residential PV systems connected to utility grids. DOE has funded most of these, either independently or at a Residential Experiment Station (RES). System cost data from government-funded individual residences are shown in Table 3.

Detailed cost data from the Northeast (NE) RES and Southwest (SW) RES are given in Table 4. Three prototype systems have been installed at the SE RES but no cost data are presently available.

Actual system costs for publicly funded installations do not include design and integration costs or overhead and profit. Labor costs are calculated based on observed man-hours and an assumed wage rate of $15/hour. Installed system costs vary from $9/W$_p$dc to $34/W$_p$dc. If a 25% integration charge is included, system costs run from $11/W$_p$ to $42/W$_p$. Experience with other systems suggests that the latter range is more reasonable for privately installed systems.

The prototype systems at the NE RES and SW RES generally had very high installation costs due to the first-of-a-kind nature of each design. These cost figures cannot be considered up to date; currently, residential PV systems are being installed for less than these figures suggest. For example, two privately funded residential systems have been designed and installed by Solar Design Associates. Their cost experience is summarized in Table 5.

E. CONCLUSION

The cost of installed PV systems has varied widely. The cost of the PRDA installations varied from $18 to $68/W$_p$dc, with no clear-cut trend toward lower system costs with either time or increased size of the installation. Similar variation in system costs is observed at both the NE and SW Residential Experiment Stations. This wide divergence is largely explained by the experimental nature of each of these government-funded installations.

More recent experience with private-sector installations has shown greater cost consistency, with system costs falling in the $11-13/W$_p$ac range. Nevertheless, these costs remain approximately an order of magnitude above levels that will allow competition with conventional bulk power sources. The next section discusses projected PV systems costs for selected system designs to 1990.

Table 4. Cost Experience at the Northeast and Southwest Photovoltaic Residential Experiment Stations, Current $

	Northeast PES (Reference 5)					Southwest RES (Reference 6)							
	GE	MIT	SX	TSC	WST	ARTU	ARCO	BDM	GE	SX	TEA	TSC	WST
Nominal Power, kW_p dc (STC)	6.6	6.8	5.0	4.8	5.1	4.9	7.4	4.5	6.7	5.1	4.3	5.3	5.5
System Turn-On	5/6/81	11/29/80	7/9/81	12/10/80	2/5/81								
Mounting Type	Direct	Stand-off	Stand-off	Integral	Integral	Stand-off	Direct	Stand-off	Direct	Stand-off	Rack	Integral	Integral
Active Array Area	76.8	84.9	68.4	47.2	69.2	55.2	88.2	54	76.2	68.4	49.4	58	73.4
Cost Component, $/$W_p$ dc													
Array	$20.55	$12.35	$14.65	$32.43	$12.03	$10.95	$ 7.06	$18.24	$19.64	$16.87	$14.54	$20.03	$10.42
Array Installation	0.26	1.06	1.18	0.45	2.38	2.90	1.08	0.46	0.28	0.90	1.31	1.01	2.61
Roof Credit[a]	-0.11	-	-	-0.19	-0.29	-0.20	-0.08	-	-0.11	-	-	-0.22	-0.16
Array Wiring	0.21	0.40	0.28	0.33	0.71	0.46	0.16	0.43	0.23	0.21	0.66	0.30	0.59
Inverter	1.83	0.47	2.56	0.73	3.33	0.76	0.58	2.73	1.80	2.51	2.81	0.64	2.32
Electric/PCU Installation	0.13	0.01	0.02	0.14	0.01	0.08	0.24	0.04	0.09	0.01	0.43	0.04	-
	$22.97	$14.29	$18.69	$33.88	$17.66	$14.95	$ 9.04	$21.90	$21.93	$20.50	$19.73	$21.80	$15.85

[a]Based on reported material costs at date of installation and a standard labor rate of $15/hr, roof credits are calculated as follows: Plywood sheathing: 0.66 $\$/ft^2$; Roofing felt: 0.17 $\$/ft^2$; Asphalt shingles: 0.92 $\$/ft^2$

GE = General Electric
MIT = Massachusetts Institute of Technology
SX = Solarex
TSC = TriSolar Corp.
WST = Westinghouse
ARTU = Applied Research & Technology of Utah Corp.
ARCO = ARCO Solar, Inc.
BDM = BDM Corp.
TEA = Total Environmental Action, Inc.

Table 5. System Cost Experience with Two Privately Funded Grid-Connected Photovoltaic Residences, 1982 $[a]

Residence	Nominal Array Output, $kW_p dc$	Completion Date	Total System Cost, $\$/W_p dc$
Massachusetts	4.5	12/1981	12-13
New Mexico	3.0	2/1982	12

[a]Information provided by Steven Strong of Solar Design Associates in telephone conversation. These costs include design, procurement, and installation. Both systems include inverters.

SECTION III

PHOTOVOLTAIC SYSTEM COST PROJECTIONS

A. OVERVIEW

A body of literature offers subsystem cost estimates for future PV systems, including array field design studies aimed at reducing installed system costs, manufacturing cost analyses for various system components, and studies of subsystem interfaces and user requirements. These studies, combined with field experience to date, provide the data base for this report. This information has been reviewed and is selectively summarized here in the context of future PV subsystem cost ranges for five PV system configurations: three 5-MW ground-mounted flat-plate systems with structures (fixed at latitude tilt, one-axis tracking with no latitude lilt, and two-axis tracking), a 5-MW ground-mounted two-axis tracking concentrator system, and a 5-kW roof-mounted residential system.

These projections should not be viewed as predictions of actual 1990 system costs. Their only purpose is to serve as baselines for examination of major system cost sensitivities (see Section IV). Technical and market uncertainties are too large to allow predictions of future PV system costs with any confidence.

The major PV cost categories and subsystems are (1) PV modules (flat-plate and concentrator), (2) dc/ac inverter, (3) array field costs, (4) land, (5) ac wiring, and (6) system integration costs. This section discusses each of these in detail.

B. FLAT-PLATE MODULES

A flat-plate module is composed of PV cells connected electrically and protected from the environment under a sheet of glass or clear plastic material. The cost of these modules can be expressed as an f.o.b. (free on board) figure that covers all factory costs (including a normal profit). In addition to the f.o.b. cost, marketing and distribution costs are usually incurred.

Projecting module costs is the most difficult and the most important component of PV system cost projections. It is the most difficult because of the multitude of promising module technologies and their wide-ranging and well funded R&D. It is the most important because of the sensitivity of system costs to module costs (see Section IV) and the widespread expectation of rapid and dramatic improvements in module technology. This report is limited to an examination of silicon modules only because of the speculative nature and the paucity of cost data on more exotic module technologies.

JPL has recently completed a comprehensive probabilistic study of potential price-efficiency combinations for flat-plate silicon modules in 1990 (Reference 1). It examined three of the more mature flat-plate module technologies (i.e., Czochralski ingot, polycrystalline ribbons, and single-crystal web). Using a Monte Carlo simulation involving 2500 different scenarios, joint probability tables on projected module cost (f.o.b.), and efficiency (NOC) were constructed (Tables 6 through 9). This analysis assumes continued funding of silicon module development by the National Photovoltaics Program and the PV industry, and assigns probabilities to the achievement of several specific technological goals. For example, the Czochralski (Cz) ingot table (Table 6) is based upon silicon material prices varying between \$12 and \$32/kg, squared-off ingots, two to five ingots pulled per crucible (at present, two have been demonstrated), three alternative sawing techniques, and a plant size of at least 25-MW/year capacity. Product yield is allowed to vary at key points in the production process. Similar assumptions are made for polycrystalline ribbon (Table 7) and single-crystal web (Table 8) cell techniques. In the case of single-crystal web, a 25% failure rate is attached to solving the remaining technical problems associated with high-speed production growth rates. This leads to a bimodal distribution.

Results for the three silicon module technologies are combined in Table 9. In each of 2500 Monte Carlo simulations, three module price and efficiency combinations are generated: one each for Cz ingot, polycrystalline ribbon, and single-crystal web. One or more of these module technologies may be dominated by one of the others. Domination is determined by total system cost.[4] As long as a module technology has projected system costs within 10% of the lowest-cost technology, it is considered competitive (not dominated) and remains in Table 9.

The data in Table 9 show a mean efficiency of 13% and a mean price of \$0.68/$W_p$ac. This study adopts the 13% efficiency mean as its projected efficiency value but has increased the projected price to \$0.85/$W_p$ac to reflect the effects of market dynamics. It does not seem likely that the PV market will settle down to a competitive equilibrium by 1990 with the requisite number of fully integrated 25-MW_p (or larger) flat-plate module facilities. Rather, the market and industry will undoubtedly be in transition, with higher markups and inefficiencies resulting in a somewhat higher average market price. This study uses 50% confidence intervals of 11% to 14% for module efficiency and \$0.60/$W_p$ac to \$1.20/$W_p$ac for module market price.

The module marketing and distribution (M&D) markup covers the expenses of advertising, maintaining an inventory, and profit along the distribution chain. This markup usually varies inversely with the size of the purchase. Therefore, large purchases (in this case, 5 MW) will tend to have a lower M&D markup than a 5-kW residential purchase. This report includes a projected marketing markup of 20% of module cost on the 5-MW purchase, and a distribution markup of \$0.027/$W_p$dc (or \$3.5/m^2). Corresponding ranges of 10% to 25% and \$0.02/W_p to 0.05/W_p were projected.

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[4]An area-related BOS cost of \$61/m^2 is assumed to obtain the system price-efficiency trade-off.

Table 6. Probability of Achieving Various Module Efficiency and Price Combinations in 1990 Using Cz Ingot Techniques, % (Reference 7)

Price (f.o.b.) 1982$	Efficiency (at NOC), %						
	10	11	12	13	14	15	16
0.43	--	--	--	--	--	--	--
0.49	--	--	--	--	--	--	--
0.55	--	--	--	--	--	--	--
0.61	--	--	--	--	--	--	--
0.67	--	--	--	--	--	--	0.04
0.73	--	--	--	--	0.12	0.24	0.08
0.79	--	--	--	--	1.04	1.68	0.52
0.86	--	--	--	1.00	6.76	7.52	1.80
0.98	--	--	0.04	5.96	16.72	10.52	1.76
1.10	--	--	--	4.80	12.80	5.16	0.72
1.22	--	--	--	2.76	5.36	2.36	0.52
1.35	--	--	--	1.96	2.52	0.96	0.12
1.47	--	--	--	0.76	2.08	0.32	--
1.59	--	--	--	0.20	0.44	0.08	--
1.71	--	--	--	0.16	0.12	--	--
1.83	--	--	--	--	--	--	--

Mean efficiency: 14%
Mean price: $\$1.05/W_p$dc

For residential PV systems, marketing and distribution markups and project design and integration fees are expected to vary greatly between tract and custom houses. Significantly different markups on major equipment (i.e., modules and inverters) are postulated for each case. Other costs, including installation costs, are assumed to be the same for both. These scenarios attempt to capture the uncertainty surrounding the structure of the residential photovoltaic industry and market in the next decade.

The residential module markup (which includes distribution) is projected at 35% of module cost (range 25% to 50%) for a tract-house purchase and 70% (range 50% to 100%) for a custom-house purchase. The higher residential figures reflect the longer distribution chain, i.e., manufacturer to central distributor to local distributor to subcontractor. The tract-house scenario

Table 7. Probability of Achieving Various Module Efficiency and Price Combinations in 1990 Using Polycrystalline Ribbon, % (Reference 7)

Price (f.o.b.) 1982$	Efficiency (at NOC), %						
	10	11	12	13	14	15	16
0.43	--	--	0.08	0.04	--	--	--
0.49	--	0.32	1.32	1.24	--	--	--
0.55	0.16	1.52	6.64	3.48	--	--	--
0.61	0.32	4.44	12.64	4.80	--	--	--
0.67	0.60	8.00	11.88	2.92	--	--	--
0.73	1.12	6.80	8.48	1.96	--	--	--
0.79	0.80	3.92	3.56	1.00	--	--	--
0.86	0.68	2.76	3.16	0.68	--	--	--
0.98	0.36	1.72	0.96	0.20	--	--	--
1.10	0.16	0.44	0.56	0.04	--	--	--
1.22	0.04	0.08	0.20	0.08	--	--	--
1.35	0.12	0.20	0.12	0.04	--	--	--
1.47	--	0.16	0.08	--	--	--	--
1.59	--	0.12	--	--	--	--	--
1.71	--	--	--	--	--	--	--
1.83	--	--	--	--	--	--	--

Mean efficiency: 12%
Mean price: $0.70/W_p dc

presumes a bulk purchase by the general contractor from the manufacturer or central distributor. We include a 2% fee for residential array warranty for completeness (range 0% to 3%), although no similar cost is assessed against the larger ground-mounted systems.

C. CONCENTRATOR MODULES

The most recent detailed study of concentrator module costs under large-scale production is a Martin Marietta array optimization study published in December 1982 (Reference 8). It projects a cost of $215/m^2 (1982$), which includes modules and inter-module dc wiring, module mounts, support tube, drive, and the controller with its cables. The array design is the second-generation Martin Marietta design. This projection assumes continued

Table 8. Probability of Achieving Various Module Efficiency and Price Combinations in 1990 Using Single Crystalline Web Techniques, % (Reference 7)

Price (f.o.b.) 1982$	Efficiency (at NOC), %						
	10	11	12	13	14	15	16
0.43	--	--	--	--	--	--	--
0.49	--	--	--	--	0.08	0.04	0.20
0.55	--	--	--	1.08	7.12	6.88	1.36
0.61	--	--	--	1.08	7.12	6.88	1.36
0.67	--	--	0.04	3.08	12.12	6.56	0.68
0.73	--	--	--	3.72	8.08	2.20	0.24
0.79	--	--	--	2.36	2.96	1.00	0.32
0.86	--	--	--	1.04	1.92	0.44	0.04
0.98	--	--	--	0.52	0.68	0.12	--
1.10	--	--	--	--	--	--	0.92
1.22	--	--	--	--	0.20	1.16	0.68
1.35	--	--	--	0.20	5.08	5.60	0.12
1.47	--	--	--	2.84	6.60	2.00	--
1.59	--	--	--	2.20	1.80	0.36	--
1.71	--	--	--	0.28	0.24	0.04	--
1.83	--	--	--	0.16	--	--	--

Mean efficiency: 14%
Mean price: $0.75/W_p$dc

technical development, a plant production rate of 3000 arrays/year (approximately 13 MW_p at STC), and long-term cost reductions in cells, lenses, and interconnects as a result of increased demand for these module production inputs. These long-term input prices are based on large-scale production.

However, plants producing only 13 MW/year cannot benefit from all of the economies of scale associated with vertically integrating the production process, i.e., producing cells and modules at the same facility. In recognition of this problem, Sandia has made an initial analysis of a 100 MW/yr concentrator production plant (Reference 9). Economies of scale in the production of photovoltaic modules are obtained by vertical integration of the entire manufacturing process, including the production of PV cells.

Table 9. Probability of Achieving Various Flat-Plate Silicon Module Efficiency and Price Combinations in 1990, % (Reference 7)

Price (f.o.b.), 1982$	Efficiency (at NOC), % 10	11	12	13	14	15	16
0.43	--	--	0.06	0.03	--	--	--
0.49	--	0.19	0.92	0.86	0.06	0.03	0.14
0.55	0.06	0.89	4.31	2.45	0.75	1.70	0.67
0.61	0.08	2.00	7.65	3.87	4.95	4.78	0.95
0.67	0.17	3.25	6.54	3.92	8.37	4.56	0.47
0.73	0.36	2.50	3.95	3.28	5.34	1.53	0.19
0.79	0.14	0.97	1.45	1.92	2.06	0.81	0.28
0.86	0.11	0.67	1.34	1.08	1.84	1.00	0.28
0.98	0.06	0.39	0.25	0.53	1.25	0.78	0.03
1.10	0.03	0.03	0.08	0.08	0.31	0.22	0.06
1.22	--	--	--	--	--	0.06	--
1.35	--	--	0.03	--	--	--	--

Mean efficiency: 13%
Mean price: $0.68/W_p$dc

Whereas the economies of scale appear to be exhausted at 25-30 MW_p production levels for flat-plate modules, a much larger plant size is required to achieve the economies of scale for concentrator arrays. The Sandia analysis suggests that material and labor costs of $90/m^2 to $130/m^2 (1982 $) may be possible for a 100 MW/yr production plant. A manufacturing multiplier of 1.3 to 1.5 to account for indirect manufacturing costs is applicable in such a case (Reference 10). Therefore, the Sandia study projects a range of planar silicon concentrator module costs in the neighborhood of $120/m^2 to $200/m^2 f.o.b. in 1990. In this report, the projected value is $150/m^2 with a 50% confidence interval of $120/m^2 to $250/m^2, at a module efficiency (sun to dc electricity) of 15% at NOC (17% at STC). This implies a nominal module cost of $1.00/$W_p$. A 15% NOC efficiency with a 13% to 16% range is projected. Marketing costs for concentrator modules are projected at 20% of module cost, the same as large flat-plate systems. However, shipping costs of $8/m^2 (range $6/m^2 to $12/m^2) are approximately twice those for flat-plate ground-mounted systems.

Concentrator modules are most attractive with high-efficiency cells. While planar silicon module efficiencies are not expected to greatly exceed 15% (at NOC) in the next several years, two alternatives offer the potential for high efficiency. Black and Veatch Engineers-Architects, under an Electric Power Research Institute (EPRI) contract (Reference 11), has developed a conceptual design for a 1995 system using a high-efficiency silicon concentrator module with a secondary concentrator. Multijunction cells have the potential to exceed 20% (at NOC), but are not expected to be commercially available by 1990. Varian Associates (Reference 12) has made some tentative cost projections for a gallium arsenide module, which may be available by the end of the decade. Although this report does not attempt to project costs for advanced concentrator systems, Table 10 gives module cost projections for the EPRI and Varian advanced concepts.

Marketing charges for concentrator modules are assumed to be the same as for the ground-mounted flat-plate system (20% of module f.o.b. costs). Distribution costs of $\$8/m^2$ (range $\$6/m^2$ to $\$12/m^2$) are based on the Martin Marietta array study.

Table 10. Advanced Concentrator Module and Installation Costs, 1982 $\$/m^2$

	EPRI Silicon 500:1 Concentrator	Varian Gallium Arsenide 400:1 Concentrator
Cell Efficiency	27% (NOC)	25% (STC)
Module Efficiency	20% (NOC)	20% (STC)
Cell Cost	31.6-63.2 (1.00-2.00/cell)	80
Module Structure		127
Module Housing	69	
Lens Parquet[a]	23-28	
Cell Package	19	
Total Module Cost	142.6 - 179.2	207
Array Structure and Installation	139	307
Total	$\$282/m^2$ to $\$318/m^2$	$\$514/m^2$

[a]Black and Veatch Engineers-Architects concept: 36 polymer lenses (6 x 6) molded on top of a glass sheet.

D. DC/AC INVERTERS

1. Large Ground Mounted

Although both 5-kW and 5-MW dc/ac inverters serve the same function (i.e., converting the direct current produced by the PV array into alternating current), the technologies involved can be quite different. Therefore, individual studies have tended to focus on inverters of a specific size. This section reviews the literature on costs of intermediate and large inverters and then addresses residential-sized inverters.

Several studies of intermediate and large PV inverters have been completed. The results of four contractor studies of intermediate-sized PV inverters are shown in Table 11 (Reference 13). Efficiencies are all close to 95%; cost projections vary from $0.11/W_pac to $0.31/W_pac (f.o.b.). These studies are based upon production runs of 100 to 1000 units/year in 1986. For the 300-kW Westinghouse Electric Corp. unit (made up of two 150-kW units), this represents an annual PV installation of 30 to 300 MW per year. Westinghouse also studied a 600-kW unit (four 150-kW units), but projected only a slight decrease from the 300-kW unit cost.

In addition, Westinghouse projected selling prices for fuel-cell inverters sized for central power station applications (3.75 to 20 MW_pac) (Reference 14). They projected selling prices of $0.09/W_pac and $0.07/W_pac for single and 10-unit production runs, respectively, of a 20-MW inverter and $0.11/W_pac and $0.09/W_pac for single and 10-unit production levels, respectively of a 5-MW_p inverter. All of these projections represent factory prices (f.o.b.) after all initial development costs have been recovered.

More recent data suggest that inverters for large ground-mounted systems will probably achieve peak efficiencies of at least 97%. At rated conditions, the estimated peak efficiency for the 750 kW_pac Helionetics inverter is 97%,

Table 11. Results of Contractor Studies of Intermediate-Range Dc/Ac Inverters

Power Output, kWac		Efficiency (Full Load/ Half/Load)	Selling Cost[a] (f.o.b.), 1982 $/$W_p$
United Technologies	80	95.4/95.5	0.143
General Electric	82	95.3/94.3	0.143
Westinghouse	90	94.2/93.7	0.172-0.208
Westinghouse	150	94.84/93.5	0.121-0.144
Garrett AiResearch	200	94	0.311
Westinghouse	300	94.69 - 93	0.106-0.127

[a]Manufacturing multiplier of 1.6 is used.

and this unit may eventually sell for close to $\$0.10/W_p$ (f.o.b.). Whether this price will be achieved by 1990 depends in large part on PV industry growth. This study's fairly conservative projection of $\$0.24/W_p$ (1982 $) for large inverters includes the installation costs. Under favorable market conditions, inverters might be installed for as little as $\$0.12/W_p$, but under unfavorable conditions prices might remain close to today's level ($\$0.35/W_p$ for nine 750-kW_p Helionetics inverters).

2. Residential

National Photovoltaics Program experience with residential power conversion units at the NE RES and Massachusetts Institute of Technology Lincoln Laboratories (MIT-LL) has generally been favorable (Reference 15). The need for automatic turn-off switches, reduced noise and radio interference levels, and other performance modifications were identified during the first year of operation. Manufacturers were generally successful in making the needed modifications, and with an exception or two the resulting second-generation devices have had an acceptable operating history. Table 12 compares four of the current (second-generation) units. Of these units, only

Table 12. Manufacturers' Price Estimates of Large-Quantity Sales of Recent Residential Inverters (Reference 15)

Manufacturer	Rated ac Output, kW	Peak Efficiency, %	Selling Price (f.o.b.), $\$/W_pac$ (1982 $)	Comments
Acheval	10.0	92	0.23 (high-quantity)	No night switch or isolation transformer. Current waveform and pcver factor probably unacceptable
Windworks, Inc.	7.4	92	0.54 (high-quantity)	Includes ac filter night switch, and isolation transformer
Helionetics, Inc. (DECC)	5.5	91	0.57 (hundreds) 0.25 (mass-produced)	Includes isolation transformer, but no night switch
American Power Conversion Corp.	4.0	92	0.49 (1000/year)	Includes isolation transformer and night switch

the Acheval Wind Electronics model is still considered unsatisfactory due to low power factor and high harmonic levels, although RF interference and noise levels still need improvement in all models. High-quantity production is expected to reduce manufacturing costs significantly.

Using the existing technology as a starting point, Sandia organized four generic studies of issues for residential and intermediate-sized inverters (References 16 through 19). The goals of the contractor studies included reduced cost, increased efficiency and reliability, and reduced harmonic propagation and volt-ampere reactive loading. Contractors were instructed to design and cost units based on 1986 technology projections and market sizes of 1000 units. Of the four contractors -- Garrett AiResearch, General Electric Co., United Technologies Corp., and Westinghouse -- only the GE design could be considered a radical departure from the current commercial technology. All contractors tended to use advanced semiconductor material, advanced transistor chip techniques, and improved logic circuits, but their conceptual designs (with the exception of GE's) were self-commutated, voltage-sourced, and either a pulse-width-modulated or a programmed-waveform inverter using power transistors. In comparison, the GE conceptual design included a high-frequency link and thyristors in the output end of the unit.

Cost projections varied greatly among the four contractors. Table 13 gives selling prices (f.o.b.) based on an indirect cost multiplier of 2.5 for GE and 1.6 for the other contractors. General Electric was treated differently due to the more innovative nature of its design, the large portion of the costs associated with components still to be designed (30%), and their own estimate of 2.5 for the manufacturing cost multiplier. The figures reported for Westinghouse include technical improvements. Judging by current rates of technology development, such improvements probably will be available by 1990. While the GE design is more innovative than the other contractor approaches, their use of high-frequency switching techniques is similar to at least three residential inverters being developed for commercial application. The high-frequency option tends to increase unit costs due to the increased number of parts, but allows the use of a 3-lb isolation transformer rather than the 70-lb units being used in more conventional units. American Power Conversion Corp.'s most recent model has a half-load efficiency of 93%, so the high-frequency option does not seem to affect inverter efficiencies significantly.

Table 13. A Comparison of Contractor Price Projections for 1986 Technology in Residential Inverters, 1982 $

Contractor	Rated ac Output, kW	Efficiency Peak/Half-Load, %	Manufacturer's Selling Price (f.o.b.), $\$/W_p$ac	Manufacturing Multiplier Used
Garrett Airesearch	8.0	90/89	0.31	1.65
General Electric Co.	10.0	94/93	0.21	2.5
United Technologies Corp.	10.0	93/91.5	0.26	1.6
Westinghouse Electric Corp.	10.0	91/91	0.33-0.39	1.6-1.9
	5.0	89/91	0.49-0.58	1.6-1.9

Several conclusions can be drawn from National Photovoltaics Program experience with required residential inverter design. A 60-Hz isolation transformer appears to limit inverter efficiency technically to 93% or less. Sandia has recently completed a requirements study for a transformerless inverter. This study concluded that eliminating the transformer might lead to a 30% reduction in unit cost as well as a 1% or 2% increase in efficiency (Reference 20).

Experience indicates that cost per peak watt increases substantially as the size of residential units decreases. A 4-kW_p to 5-kW_p unit appears to cost 1.4 to 1.5 times as much as a 10-kW_p unit in $\$/W_p$, due to fixed cost elements such as controls, capacitors, and certain labor and packaging inputs. Therefore, the GE design might cost \$0.29 to $\$0.31/W_p$ for a 4-kW_p or 5-kW_p unit. Even if this estimate is optimistic for GE's production assumption of 1000 units/year, it is consistent with Helionetic's estimate of mass-production costs for their current technology inverter ($\$0.25/W_p$ for their 5.5-kW_p unit). Generally speaking, residential inverter costs are expected to fall between $\$0.25/W_p$ (assuming mass production) and $\$0.50/W_p$ (if production rates are low). Residential inverters are presently selling at $\$1.00/W_p$ to $1.50/W_p$ for production rates of less than 10. The projection is $\$0.31/W_p$ for a 5-kW_p inverter (f.o.b.), with a range of $\$0.25/W_p$ to $\$0.50/W_p$.

Marketing and distributing markup percentages for residential inverters are assumed to be equivalent to the markups on residential arrays: 35% and 70% of inverter f.o.b. costs for tract and custom houses, respectively, with corresponding ranges of 25%-50% and 50%-100%.

Inverter installation costs are expected to decrease as inverter designs improve. The new high-frequency switching designs have greatly reduced the size and weight of residential units. Installation of inverters is assumed to take place at the same time that the wiring, metering, and lightning protection devices are installed (during construction of the residence), and is projected at $\$0.07/W_p$ac. This figure is consistent with Bechtel's estimate of $\$0.065/W_p$ac (Reference 12) and an Albuquerque electrical contractor's (Uhl & Lopez Engineers, Inc.) estimate of \$320 to install a 4-kW_p to 6-kW_p inverter (Reference 21). The projected range is \$0.03 to $\$0.09/W_p$.

E. INSTALLED ARRAY

1. Large Ground-mounted

For ground-mounted systems, installed array costs are assumed to include: (1) site preparation and security fencing, (2) installation of array structure, (3) installation of modules onto the array structure including any intermediate steps such as panels, and (4) field wiring. For roof-mounted systems, installed array costs include: (1) installation of array structure and modules, integral with the roof, during initial construction; (2) sealing the array to provide a weather barrier, and (3) intra-array wiring (wiring from the array to the inverter is considered separately). Ground-mounted arrays are considered first, followed by a discussion of installation costs for roof-mounted residential systems.

Several design studies have been aimed at optimizing the design of large central-station-sized ground-mounted photovoltaic systems. Special attention has been paid to array structures and their impact on system costs. However, for such an optimization to be made, not only must the complex mechanical and electrical interrelationships between system components be identified, but also their effect on system cost and life-cycle cost must be evaluated. This requires reliable cost data for all system components. Unfortunately, when system designs are being projected into the future, such empirical data generally are not available.

Array structures are composed largely of readily available and fairly abundant materials, but there are several potential design costing pitfalls. Optimal array field design is dependent upon area-related costs, particularly electrical wiring and component costs. Several specialized electrical components are currently not available commercially in the quantity required by a mature photovoltaic industry. Therefore, their costs are not easily evaluated, and it is difficult to optimize system design. Area-related costs are also closely tied to shadowing losses. In addition, as labor and material-saving modifications in array structures are introduced, specialized materials and/or equipment may be required.

The ground-mounted systems being considered include three flat-plate systems (fixed at latitude tilt, single-axis tracking with no latitude tilt, and two-axis tracking) and a point-focus Fresnel two-axis tracking concentrator system. Array field cost estimates from several contractors' fixed-flat-plate design studies are given in Table 14 (References 22 through 27). These designs have not been tested in the sense that there are no large field installations corresponding to these designs. The large

Table 14. Area-Related Balance-of-System Costs for Flat-Plate Ground-Mounted Photovoltaic Systems (1982 $)

	BHRK[a]		BHKR[a]		Bechtel			Battelle	JPL	Black & Veatch
	Wood	Wood (Automated)	Steel/ Concrete	Steel/ Concrete (Automated)	Wood	Concrete	Wood[b]	Wood	Wood	Concrete
Publication Date	11/82	11/82	Fall '83	Fall '83	11/82	11/82	11/82	12/82	6/81	Fall '83
Installation Size, MW_p	10	10	10	10	10	10	50	0.122	50	10
Projection Date	1986	1986	1986	1986	1986	1986	1980	1982	1980	1995
Cost Component, $\$/m^2$										
Site Preparation	3.96	3.96	4.79	4.79	N/A	N/A	N/A	9.32	N/A	2.44
Installed Array	15.12	12.35	18.70	16.34	34	33	41	26.61	40	38.52
dc Wiring	4.30	4.30	5.64	5.64	N/A	N/A	N/A	18.53[c]	N/A	8.32
Total	$23.38[d]	$20.61[d]	$29.13[d]	$26.77[d]				$54.46		$49.28

[a]BHKR = Burt Hill Kosar Rittelmann Associates

[b]These figures represent a Bechtel assessment of the JPL wood design described in the table.

[c]After installing a 30-kW system at Sandia National Laboratories in Albuquerque, Battelle has lowered its dc wiring cost estimate to $\$14/m^2$ (Reference 2).

[d]Does not include panel assembly. Bechtel estimates this cost to be approximately $\$20/m^2$.

flat-plate fields currently being installed (SMUD Phase I and the two ARCO fields) use tracking flat-plate structures. In Table 15, two further cost estimates are cited (References 2 and 3). These estimates are based upon a smaller field size (100 kW), but they have been field tested. Two 30-kW fields (Hughes and Battelle) were installed at Sandia.

Table 15 presents Battelle's and Hughes's initial projection of array field costs, the observed cost of an initial procurement and installation, and an updated cost projection. The actual cost of the two 30-kW installations

Table 15. Cost Summary of the Battelle and Hughes 30-kW_p Installations at Sandia Central Receiver Test Facility, Albuquerque, New Mexico, 1982 $

Design	30 kW as Built, $/m^2	Second 30 kW[a] Installation, $/m^2	Original 100-kW Estimate, $/m^2
Battelle			
Site Preparation	1.83	3.56	4.35
Foundation	71.96	30.50	20.82
Support Structure	31.15	18.94	9.98
Field Electrical	29.21	13.41	18.53
Subtotal	134.15	66.41	53.68
Fence	11.97	11.97	4.97
Total[b]	146.12	78.38	58.65
Hughes[a]			
Electrical Hardware	22.68	16.36	15.55
Structures and Foundation Hardware	21.48	16.90	16.73
Installation	92.41	56.23	27.27
Subtotal	136.57	89.49	59.55
Fence	11.97	4.07	4.07
Total[b]	148.54	93.56	63.62

[a]Hughes second installation is based on a 100-kW installation.

[b]Do not include design and integration costs.

seems quite high, due primarily to integration costs (not included in the table) and subcontractor contingency. Nevertheless, area-related costs were still only 25% to 30% of previous PRDA installations. Based on observations of actual labor and material requirements (once the crew had gained experience) an updated projection of $53.50/m^2$ might be made for a 100-kW field, because of observed savings in electrical field labor requirements. This still assumes an experienced crew and includes site preparation (with a fence), panel assembly and array installation, structure costs, and field wiring.

Given present electrical design uncertainties and possibilities for economies of scale in larger fields, an area-related cost of $50/m^2$ is projected for 1990. Although the use of wood or other materials may reduce these costs, potentially high field electrical costs may also occur, raising costs above this figure. Thus, the projected cost range is $45/m^2$ to $60/m^2$.

While several design iterations have been made on optimized fixed flat-plate array fields through the Photovoltaic Systems Definition and Applications Project at Sandia, the literature on tracking flat-plate designs is not as extensive. The SMUD single-axis tracking and ARCO two-axis tracking array fields represent the first-generation of tracking flat-plate designs (similar to the first application of Martin Marietta point-focus Fresnel concentrator arrays used at the Sky Harbor and Soleras installations). The SMUD Phase I field costs are expected to be $110/m^2$. The ARCO figures are proprietary. In the Black and Veatch study for EPRI mentioned above (Reference 27), 1995 PV system designs and costs for tracking flat-plate systems were estimated (Table 16). The preliminary results of this study suggest that array field costs of approximately $50/m^2$ and $72/m^2$ are possible by the year 1995 for single-axis and two-axis tracking systems, respectively. The

Table 16. Projections, 1995, of Area-Related Costs, 1982 $
(Reference 27)

Cost Category	Fixed Flat-Plate, $/m^2$	Single-axis Tracking Flat-Plate, $/m^2$	Two-axis Tracking Flat-Plate, $/m^2$	Two-axis Tracking Concentrator, $/m^2$
Site Preparation	2.44	3.39	4.70	4.88
Panel Array Structure and Support	38.52	43.81	68.37	121.48
Field Electrical[a]	8.32	10.94	16.30	19.27
	49.28	58.14	89.37	145.63

[a]Does not include ac substation costs or station power.

Black and Veatch designs use linear actuators in the tracking structures, an untested approach. These projections are considered a lower extreme of area-related BOS costs for tracking arrays and are not within the 50% band projected for 1990.

Projections for single-axis and two-axis tracking array structure and installation costs are set at $\$65/m^2$ and $\$110/m^2$, respectively, with corresponding 50% confidence intervals of $\$55/m^2$ to $\$80/m^2$ and $\$90/m^2$ to $\$135/m^2$. These figures are based loosely on the continuing Black & Veatch analysis for EPRI. There are very little other non-proprietary data upon which to base these projections.

Several recent studies of concentrator array field costs in central-station applications are summarized in Table 17 (References 8, 23, 28, 29,

Table 17. Array Field Cost Projections for Planar Silicon Point-Focus Fresnel Concentrators

Cost Component	GE	Martin Marietta	Battelle	Burt Hill Kosar Rittelmann Stand.	Burt Hill Kosar Rittelmann Auto.	Martin Marietta Central-Station	Sandia
Field Size, MW	0.400	0.500	0.500	10.0	10.0	100.0	0.500
Array Structure and Drive	66.0	126.5	--	--	--	--	50-60
Tracking and Controller	12.7	--	110-12.5	--	--	2.91	7.0
Site Preparation and Fence	--	--	15.7	10.1	10.1	6.3	6.0
Foundations	--	8.0	15.5	10.9	10.3	9.2	6.5
Panel Installation	23.1	25.0	--	8.1[a]	5.9[a]	3.4	15.0
Field Electrical	--	--	73.6	28.9	28.9	41.6	32.0
Total[b]							116.5-126.5

[a]Includes array wiring.

[b]Total not available for most columns due to incomplete data.

and 30). These contractor studies represent initial designs rather than optimization studies. As these studies are not consistent in their definition of field costs, Sandia has synthesized these reports.[5] This synthesis is given in the last column of Table 17. Sandia has identified several areas where potential cost savings can be made, including improved control logic, reduced grounding costs, reduced numbers of junction boxes, and the elimination of ac power wiring to the arrays through use of radio signals and dc-powered drive mechanisms, but these ideas have not yet been thoroughly investigated. Area-related costs are assumed to include the cost of the drive and control mechanisms and collector panel structure and assembly. Array field costs are projected to lie between $100/m^2$ and $185/m^2$, with an expected value of $125/m^2$, based primarily upon Sandia's synthesis.

2. Residential

The discussion of residential systems is limited to 5-kW integrally mounted arrays installed during the initial construction of the house. Other installation options are believed to be more costly.[6]

The 1979 Burt Hill Kosar Rittelmann Associates (BHKR) report Residential Photovoltaic Module and Array Requirements (Reference 31), presents a good example of the first generation of low-cost residential array designs. It uses readily available construction materials and familiar construction techniques; costs were estimated on the basis of experienced crews and a mature residential photovoltaic market. The report arrived at a figure of $72/m^2$ (1982 $) before subcontractor markups for array structure and installation.

Several recent studies have looked at second-generation designs, which used more sophisticated materials or construction techniques to reduce labor requirements. A GE design uses rolled-steel support channels designed for ease of installation and water shedding (Reference 32). A JPL design seeks to reduce array weight by using advanced plastics (Reference 33). Of these two, the GE design is at a more advanced stage of development. The GE final report projects array structure and installation costs of $40/m^2$ (in 1980 dollars before subcontractor overhead and profit). This cost is based on fairly optimistic assumptions about labor productivity, but may be consistent with 1990 installations, assuming experienced contractors and crews and a large-scale residential market. Cost estimates for the rolled-steel support channel and closure cap are based on bulk production of the pieces, and inventory and marketing costs are not included. In light of the uncertainty about industry structure, $40/m^2$ must be considered optimistic. However, doubling the cost of the rolled-steel items in the GE report only increases the cost to $50/m^2$, still a substantial improvement over the BHKR 1979 figure of $72/m^2$. The $50/m^2$ (1982 $) figure is the one chosen as the most likely in 1990, with $41/m^2$ to $72/m^2$ as the projected range. In addition, a projected 20% subcontractor mark-up is applied to this installation cost with

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[5]Maish, A., Sandia National Laboratories, private communication, April 1983.

[6]Retrofitting requires dismantling the existing roof. Racks mounted on the roof are more expensive to install, and arrays placed directly on the roof suffer from energy losses due to higher PV cell operating temperatures.

a range of 15% to 25%. Further optimization of structural designs may drive costs well below this range. The JPL design requires development of an advanced polymer capable of meeting cost, safety, and performance criteria.

In addition, the PV system is credited with the cost of roofing materials that are displaced by the PV array. The projected roof credit of $\$30/m^2$ for 1/2-in. plywood, 15-lb felt, and 325-lb asphalt shingles is based on the 1979 BHKR study (Reference 31). With a 20% subcontractor markup and a 25% general contractor markup, this amounts to $\$45/m^2$. Without this roof credit, the projected costs for both custom and tract residential PV systems (see III H 2) would increase by $\$0.44/W_p$ in Phoenix and $\$0.58/W_p$ in Boston.

F. LAND, AC WIRING, AND SYSTEM INTEGRATION COSTS

Because ground-mounted photovoltaic systems are fairly land-intensive, they are not as attractive where land costs are high. For this reason, the PV literature has tended to assume installation in fairly low land-cost areas. The nominal projection is \$1200 per acre, with a range of \$0-\$6000 per acre.[7]

To obtain land costs in units of array area, land packing factors of 40% for fixed, 30% for single-axis designs, and 20% for two-axis tracking designs were assumed. At \$1200 per acre, land costs are not a significant portion of system costs.

The ac wiring subsystem connects the power conditioning unit to the power-plant switchyard. The ac wiring subsystem cost for a 5-MW ground-mounted system is based upon a Bechtel analysis of balance-of-system costs prepared for EPRI (Reference 12). The Bechtel estimate is $\$0.012/W_p$ for the wiring and $\$0.014/W_p$ for the switchyard itself (1982\$). Bechtel estimated a range of $\$0.013/W_p$ to $\$0.036/W_p$ for the entire subsystem. The projection is $\$0.03/W_p$ for the ac subsystem with a range of $\$0.02/W_p$ to $\$0.05/W_p$.

Wiring costs for a 5-kW roof-mounted residential PV system include junction boxes for connection to the module source circuits as well as the dc conduit and wiring from the array to the power conditioning unit. On the ac side of the inverter, ac conduit connects the inverter, circuit breakers, switch, and meters. Metering costs are based on a standard kilowatt hour meter. Protection devices include a circuit breaker, disconnect switch, and grounding. Lightning protection would be needed in high-risk areas, but this cost is not assessed to the photovoltaic system.

[7]The SMUD field is on land surrounding the Rancho Seco nuclear plant. This land is considered to have little or no opportunity cost to the utility.

Bechtel estimates these costs at \$0.04/$W_p$ac to \$0.05/$W_p$ac plus an additional \$1/m^2 for grounding. This is based upon a 10-kW_pac system. As these costs are not strictly proportional to peak power and array area, the unit cost of a 4.3-kW_pac system will be higher. Members of the JPL System Research and Technology subprogram have suggested a flat figure of \$367 for these devices, which is consistent with the Bechtel figures if 50% of the costs are assumed not to vary with system size. Widely diverse figures can be found in the photovoltaic literature for metering and protection devices.

Engineering and system integration for a central-station-sized PV system includes engineering and construction management, administrative overhead, profit and a project contingency fund. Sales tax may be included; interest during construction is not. The assumption is made that by 1990 system designs will be stable, and, therefore, engineering and management costs are projected to be fairly low: 25% of hardware and installation costs with a range of 20% to 35%.

System integration for the residential system includes not only contractor profit, overhead, and sales taxes but also any design or engineering costs assessed to the PV system. These costs are assumed to vary from 20% to 60% of direct system costs, depending on the construction scenario. A projected fee of 25% is assessed for a tract home and 50% is assessed for a custom-designed home, with respective ranges of 20% to 30% and 40% to 60%.

G. SUBSYSTEM COST PROJECTION SUMMARY

Subsystem cost projections are summarized in Table 18.

H. INSTALLED SYSTEM COSTS

1. System Ratings

The energy delivered by a PV system varies with the solar insolation incident on the array. Module and array ratings do not attempt to account for differences. System ratings that reflect the actual differences in observed peak power across locations, however, can be established. In this report, a site-specific system rating is adopted. Under this scheme, the peak insolation and ambient temperature combination at a given site is used to rate a PV system at that site.[8] Table 19 gives peak conditions for three sites: Phoenix, Miami, and Boston. This leads to a 5-MW_pac system in Boston that will have a larger array area than a 5-MW_pac system in Phoenix. Table 19 lists the array area required for each of the PV systems discussed in this report at the three locations. In deriving total installed system costs, the product of the array area in Table 20 and area-related costs is added to the product of rated system size and power-related costs. This rating method

[8]The "peak" conditions are based upon EPRI nominal peak operating conditions; EPRI advocates use of this system PV rating method.

Table 18. Cost Projections, 1990, for Selected PV Subsystems, 1982 $

	Projected Cost or Efficiency	Projected Range
Flat-Plate Modules		
Efficiency (NOC)[a], %	13	11 to 14
Price (f.o.b.), $\$/W_p$dc(SOC)	0.85	0.60 to 1.20
M&D (5 MW), % of module cost	20 + $0.027/W_p$	10 to 25 + 0.020 to $0.05/W_p$
M&D (5 kW), % of module cost		
Tract House	35	25 to 50
Custom House	70	50 to 100
Residential Warranty	2	0 to 3
Concentrator Modules (Silicon)		
Efficiency (NOC)[a]	15%	13% to 16%
Price (f.o.b.), $\$/m^2$	$150	$120-$250
M&D, % of module cost	20% + $\$8/m^2$	10% to 25% + $\$6/m^2$ to $\$12/m^2$
dc-ac Inverter		
5-MW Unit		
Installed Price, $\$/W_p$ac (SOC)	$0.24	$0.12 to $0.30
5-kW Unit		
Price (f.o.b.), $\$W_p$ac (SOC)	$0.31	$0.25 to $0.50
M&D Markup, % of inverter cost		
Tract House	35%	25% to 50%
Custom House	70%	50% to 100%
Installation, $\$/W_p$ac (SOC)	$0.07	$0.03 to $0.09
Array Installation, $\$/m^2$		
5-MW Field		
Fixed Flat-Plate	$50	$45 to $60
One-Axis Tracking Flat-Plate	$65	$55 to $80
Two-Axis Tracking Flat-Plate	$110	$90 to $135
Concentrator	$125	$100 to $185
5-kW Integral Roof Mount	$50	$41 to $72
Subcontractor Markup	20% of installation cost	15% to 25%
Land, ac Subsystem		
Land	$1200/acre	$0.0/acre to $6000/acre
5-MW Field, $\$/W_p$ac	$0.03	$0.02 to $0.05
5-kW Residential	$367	$300 to $500
Engineering & Integration Fee, % of subtotal		
5-MW Field	25%	20% to 35%
5-kW Residential		
Tract House	25%	20% to 30%
Custom House	50%	40% to 60%

Table 19. Rating Conditions[a]

	Peak Insolation[b], kW/m^2	Ambient Temperature, ^oC
Phoenix		
Flat-Plate	0.990	29
Concentrator	0.860	29
Miami		
Flat-Plate	0.821	27
Concentrator	0.634	26
Boston		
Flat-Plate	0.676	19
Concentrator	0.521	19

[a]Based upon EPRI's Nominal Peak Operating Conditions. Miami's and Boston's figures are reported in Reference 34. The Phoenix figures were provided orally by Roger Taylor of EPRI.

[b]Flat-plate figures are total insolation at latitude tilt. Concentrator figures are direct normal insolation. Both are based on Typical Meteorological Year data.

corrects partially for actual differences in system output across locations, allowing somewhat greater comparability in cost projections across sites. Thus, if total insolation varied strictly in proportion to peak isolation across sites, our cost projections for fixed flat-plate systems (for example) across locations would reflect systems that yielded equivalent amounts of electrical energy.

However, peak power does not vary proportionally with total solar insolation across geographic locations or among system types. For example, flat-plate tracking systems will encounter approximately the same peak conditions as flat-plate fixed-tilt systems in the same location, but will deliver significantly more energy. Thus, comparison of systems on the basis of cost per unit of rated peak output are subject to large error. Such comparisons must be made on the basis of cost per unit of energy ($/kWh) as shown in Appendix A.

2. Installed System Cost Projections

The 1990 installed system cost projections for the five PV systems discussed in this report are summarized in Tables 21 to 25. These projections will be used as the baseline in the next section to examine major system cost sensitivities.

Table 20. Required Array Aperture Area

	Required Aperture Area, m^2		
	Phoenix	Miami	Boston
5-MW_pac Systems			
Flat-Plate[a] (13% at NOC)			
Fixed	45,300	52,400	59,800
Single-Axis Tracking	45,300	52,400	59,800
Two-Axis Tracking	45,300	52,400	59,800
Concentrator			
(15% at NOC)	44,000	56,200	65,700
5-kW_pac Systems Flat-Plate Residential (13% at NOC)	48.9	56.7	64.7

[a]The peak operating conditions for fixed flat-plate systems at latitude tilt are also used for the tracking flat-plate systems.

Table 21. 1990 Projection of Installed PV System Cost: 5-MW_pac, Fixed, Ground-Mounted, Flat-Plate

Cost Category	Area-Related, $\$/m^2$ array	Power-Related, $\$/W_p$ac
Modules (13% at NOC)		
$0.85/$W_p$dc (SOC)	110.0	
Marketing (20%)	22.0	
Distribution ($0.027/$W_p$dc)	3.5	
Land ($1200/acre)	0.75	
Array, Installed	50	
Dc-Ac Inverter, Installed		0.24
Ac Subsystem, Installed		0.03
System Integration, Engineering, Contingency, and Profit (25%)	46.56	0.07
Total Installed Cost, $\$/m^2$ + $\$/W_p$ac	233	0.34
Installed Cost		
Phoenix		2.45
Miami		2.78
Boston		3.13

Table 22. Projection, 1990, of Installed PV System Cost: 5-MW_pac, Single-Axis Tracking, Ground-Mounted, Flat-Plate

Cost Category	Area-Related, $\$/m^2$ array	Power-Related, $\$/W_p$ac
Modules (13% at NOC)		
$0.85/$W_p$dc (SOC)	110.0	
Marketing (20%)	22.0	
Distribution ($0.027/$W_p$dc)	3.5	
Land ($1200/acre)	1.0	
Array, Installed	65.0	
Dc-Ac Inverter, Installed		0.24
Ac Subsystem, Installed		0.03
System Integration, Engineering, Contingency, and Profit (25%)	50.44	0.07
Total Installed Cost ($\$/m^2$ + $\$/W_p$ac)	252	0.34
Installed Cost		
Phoenix		2.62
Miami		2.98
Boston		3.35

Table 23. Projection, 1990, of Installed PV System Cost: 5-MW_pac, Two-Axis Tracking, Ground-Mounted, Flat-Plate

Cost Category	Area-Related, $/m^2 array	Power-Related, $/$W_p$ac
Modules (13% at NOC)		
$0.85/$W_p$dc (SOC)	110.0	
Marketing (20%)	22.0	
Distribution ($0.027/$W_p$dc)	3.5	
Land ($1200/acre)	1.5	
Array, Installed	110.0	
Dc-ac Inverter, Installed		0.24
Ac Subsystem, Installed		0.03
System Integration, Engineering, Contingency, and Profit (25%)	61.75	0.07
Total Installed Cost ($/m^2 + $/$W_p$ac)	309	0.34
Installed Cost		
Phoenix		3.14
Miami		3.58
Boston		4.04

Table 24. Projection, 1990, of Installed PV System Cost: 5-MW$_p$ac Concentrator

Cost Category	Planar Silicon Point-Focus Fresnel: Area-Related, \$/m^2 array	Planar Silicon Point-Focus Fresnel: Power-Related, \$/W$_p$ac
Modules (15% at NOC)		
Module Cost f.o.b.	150.0	
Marketing (20%)	30.0	
Distribution	8.0	
Land (\$1200/acre)	1.5	
Array, Installed	125.0	
Dc-ac Inverter, Installed		0.24
Ac Subsystem, Installed		0.03
System Integration, Engineering, Contingency, and Profit (25%)	78.62	0.07
Total Installed Cost (\$/m^2 + \$/W$_p$ac)	393	0.34
Installed Cost		
Phoenix		3.80
Miami		4.76
Boston	5.50	

Table 25. Projection, 1990, of Installed PV System Cost: 5-kW_pac, Integral-Mount, Residential

Cost Category	Tract House: Area-Related, $/m^2 array	Tract House: Power-Related, $/$W_p$ac	Custom House: Area-Related, $/m^2 array	Custom House: Power-Related, $/$W_p$ac
Modules (13% at NOC)				
$0.85/$W_p$dc (SOC)	110.0		110.0	
M&D Markup (35%, 70%)	38.5		77.0	
Warranty (2%)	2.2		2.2	
Array, Installed				
Labor & Materials	50.0		50.0	
Subcontractor Markup (20%)	10.0		10.0	
Dc-ac Inverter,				
Price (f.o.b.)		0.31		0.31
M&D Markup (35% tract, 70% custom)		0.11		0.22
Installation		0.07		0.07
Meters, Wiring, and Protection Devices		0.07		0.07
System Integration (25% tract, 50% custom)	52.7	0.14	124.6	0.33
Roof Credit	45.0		45.0	
Total Installed Cost	218	0.70	329	1.00
Installed Cost				
Phoenix		2.83		4.22
Miami		3.17		4.73
Boston		3.52		5.26

SECTION IV

SENSITIVITY ANALYSIS

A. INTRODUCTION

The previous section has quantified the potential variation in 1990 PV subsystem costs and efficiencies. This section analyzes the impact of variations in subsystem costs on total system cost.

A probabilistic estimate of total system cost depends on each subsystem's cost uncertainty and the degree of correlation between subsystem costs. If subsystem costs are assumed to be positively correlated, i.e., move in the same direction, a probabilistic system cost projection will be spread over a much wider range than if each subsystem's cost moves independently. Both market size and technical development influence PV system costs. These influences are neither perfectly correlated nor completely independent. Favorable market conditions may tend to reduce each subsystem's cost as economies of scale are achieved. Therefore, uncertainty concerning market size and structure introduces a positive correlation among subsystem costs. Technological uncertainty, on the other hand, is more likely to affect each subsystem independently.

A detailed probabilistic analysis of total system cost -- requiring not only an assessment of technological issues but also a probabilistic evaluation of market size and structure -- is beyond the scope of this report. Instead, this analysis evaluates instances of dependence and independence among subsystem costs. Section IV B looks at the case where all cost components move together, and Sections IV C through IV F analyze the independent impacts of changes in module cost and efficiency, area-related balance-of-system costs, inverter cost and efficiency, and module marketing and distribution markups and system integration fees, respectively.

B. SYSTEM COST RANGES

The analysis of projected subsystem costs found in the previous section was limited to three loosely defined points on a probability distribution function. These points were an expected or projected cost and two extreme points, defined as the end points of a 50% confidence interval around each subsystem's projected cost in 1990.

To construct a similar confidence interval for total system cost, several simplifying assumptions have been made. Just as the projected value of total system cost was obtained using the sum of projected subsystem costs, extreme values can be obtained using the corresponding extreme subsystem cost values. This assumes that every cost parameter moves simultaneously to its extreme value (that subsystem costs are perfectly correlated). However, module efficiency, inverter efficiency, wiring and mismatch losses, and, in the case of the residential systems, the efficiency loss due to the integral mounting scheme are held constant at their projected values. Due to the

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conservative nature of these assumptions, there is much less than a 50% chance of total system cost falling outside the generated range. The resulting interval will tend to overstate the total system cost uncertainty to the extent that subsystem costs actually are independent. Resulting system cost ranges are presented in Table 26 and illustrated in Figures 1 through 6.

Table 26. Installed 1990 System Cost Projections and Ranges[a], 1982 $

System	Projected System Costs $/m^2$ + $\$/W_p$ac	Projected System Cost[b], $\$/W_p$ac Phoenix	Miami	Boston
Ground-Mounted ($5\text{-}MW_p$ac)				
Flat-Plate Fixed	233 + 0.34 (160-358) (0.17-0.47)	2.45 (1.62-3.72)	2.78 (1.85-4.22)	3.13 (2.08-4.75)
One-Axis Tracking	252 + 0.34 (172-387) (0.17-0.47)	2.62 (1.73-3.98)	2.98 (1.97-4.53)	3.35 (2.23-5.10)
Two-Axis Tracking	309 + 0.34 (214-464) (0.17-0.47)	3.14 (2.11-4.68)	3.58 (2.41-5.33)	4.04 (2.73-6.02)
Concentrator				
Planar Silicon	393 + 0.34 (286-614) (0.17-0.47)	3.80 (2.69-6.62)	4.76 (3.38-8.32)	5.50 (3.93-9.64)
Roof-Mounted ($5\text{-}kW_p$ac)				
Tract House	218 + 0.70 (128-382) (0.48-1.22)	2.83 (1.73-4.96)	3.17 (1.93-5.55)	3.52 (2.14-6.16)
Custom House	329 + 1.00 (185-606) (0.64-1.90)	4.22 (2.45-7.83)	4.73 (2.74-8.77)	5.26 (3.03-9.74)

[a]Ranges appear in parentheses.

[b]These are site-specific peak power ratings based on EPRI's nominal peak operating conditions.

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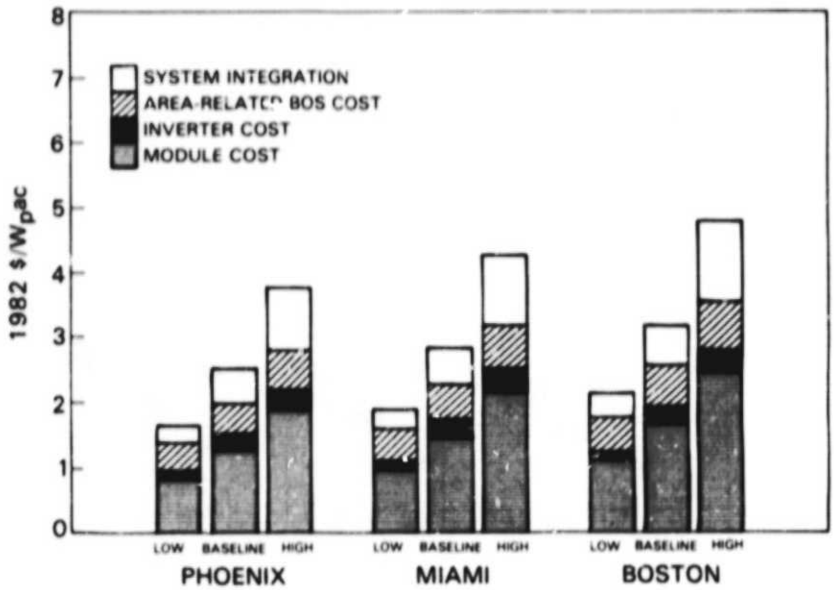

Figure 1. Photovoltaics System Cost: 5-MW Fixed Flat-Plate

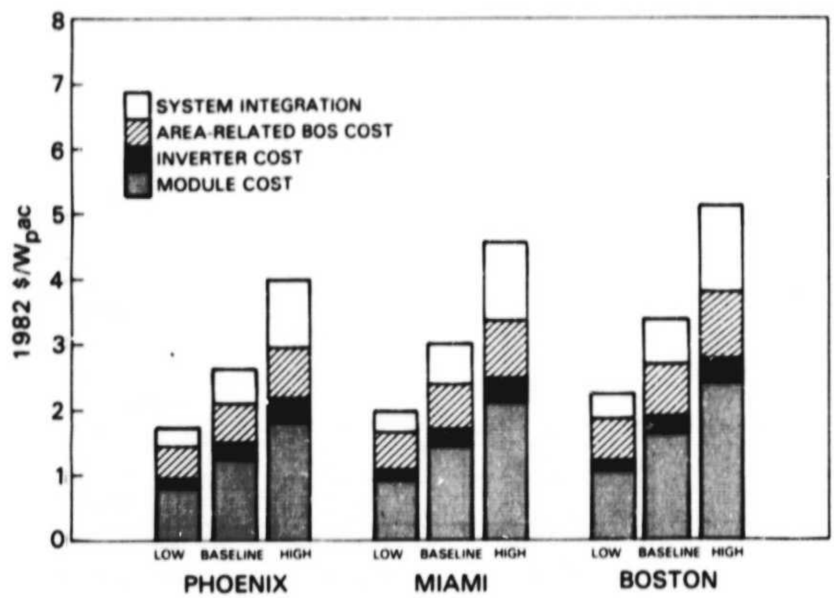

Figure 2. Photovoltaic System Cost: 5-MW Single-Axis Tracking Flat-Plate

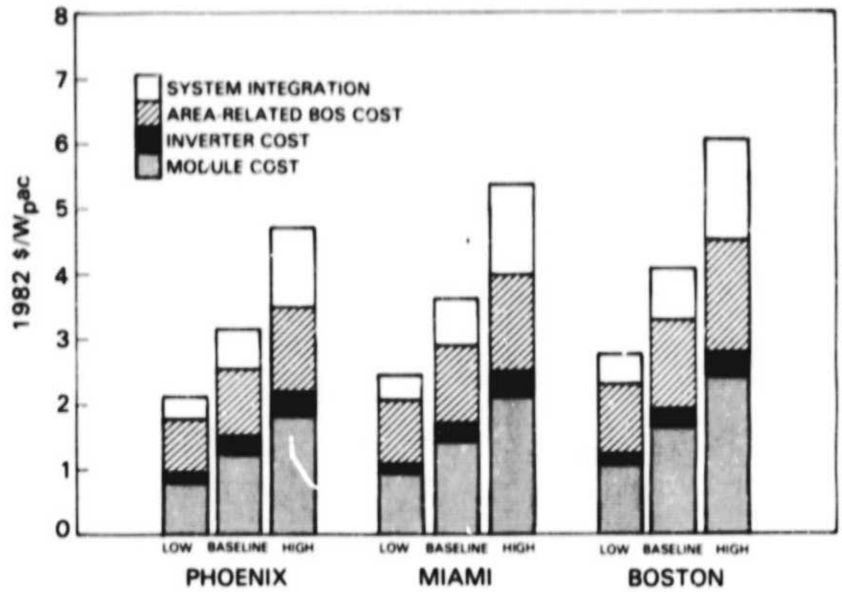

Figure 3. Photovoltaic System Cost: 5-MW Two-Axis Tracking Flat-Plate

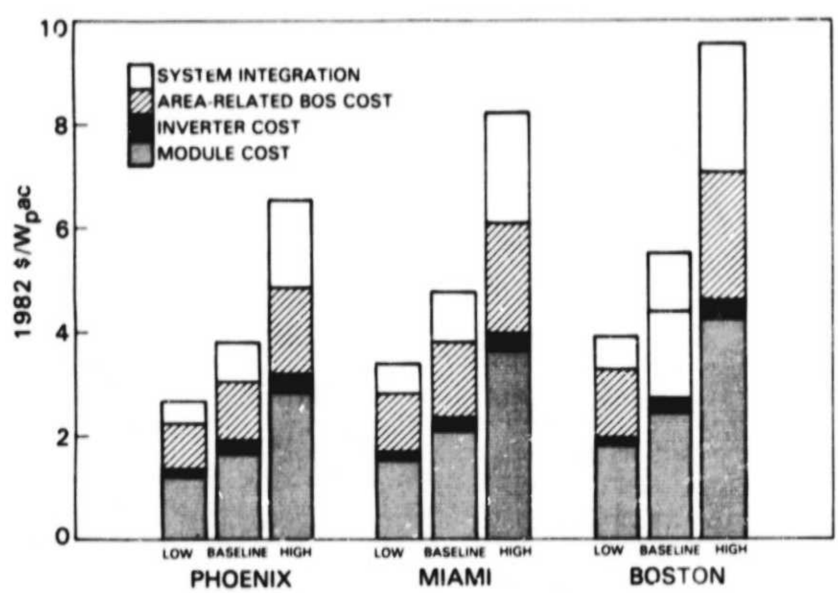

Figure 4. Photovoltaic System Cost: 5-MW Concentrator

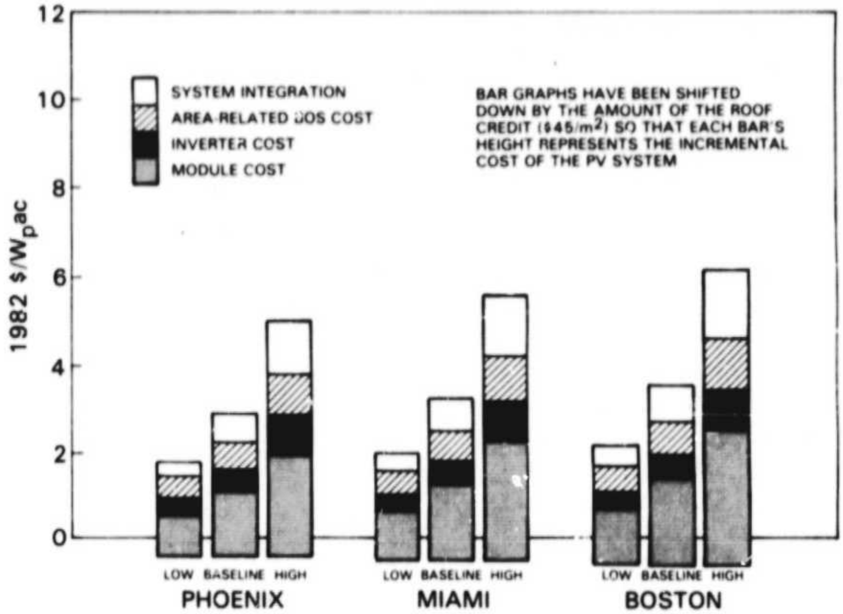

Figure 5. Photovoltaic System Cost: 5-kW Residential (Tract House)

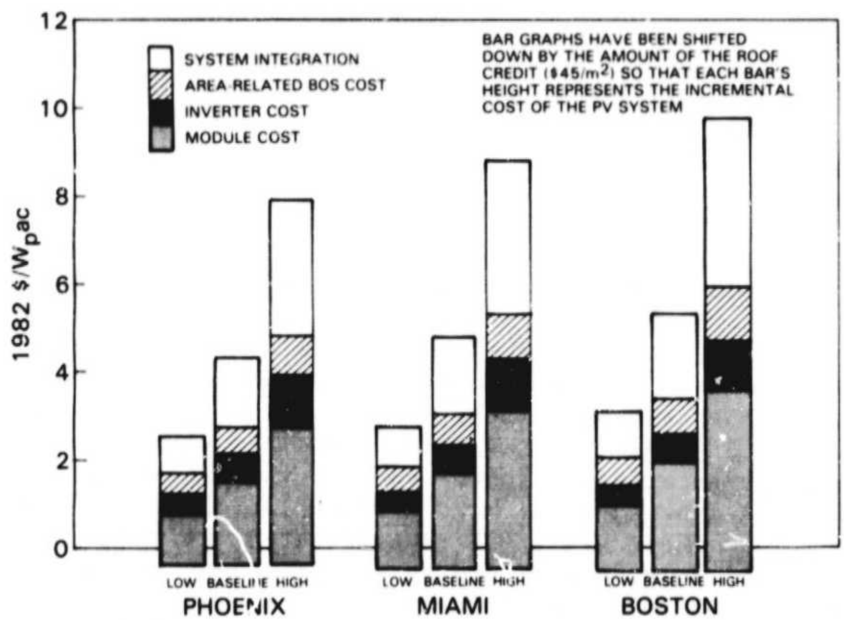

Figure 6. Photovoltaic System Cost: 5-kW Residential (Custom House)

C. SENSITIVITY TO MODULE COST AND EFFICIENCY

The preceding subsection discussed the effect on projected system costs of simultaneous movements of all subsystem costs; this subsection and those following focus on movements of, at most, two parameters at a time. In this subsection, Figures 7 through 11 illustrate the impact of module cost and efficiency on installed system cost. These figures can also be used to estimate the value of changes in module efficiency at a given system cost. In Figure 7, the projected value of installed system costs, $2.27/$W_p$ac, is achieved with a 13% module at $0.85/$W_p$dc (the baseline case), with an 11% module at $0.79/$W_p$dc, or with a 15% module at $0.89/$W_p$dc. This trade-off between module efficiency and price assumes that all other cost parameters remain at their baseline values. Similar equivalent module efficiency-cost pairs have been developed for the other system configurations and are included here in Table 27. Generally, as area-related costs increase in proportion to total system costs, the value of increased module efficiency also increases. Thus, the two-axis tracking designs seem much more sensitive to module efficiency than the other systems. Note that, as expected, system costs are very sensitive to module cost. Typically, a $0.50 decrease in module cost reduces system costs by twice as much ($1.00/$W_p$). This effect is most pronounced for the custom house, which imposes heavy M&D costs on its modules. Clearly, reduced module costs and increased module efficiencies are effective methods of reducing the cost of PV systems.

D. SENSITIVITY TO AREA-RELATED BALANCE-OF-SYSTEM COSTS

This subsection (Figures 12 to 16) examines the effect on system cost of changes in the assumed value of area-related balance-of-system costs. Note that the fixed flat-plate systems (Figures 12 and 16) show the least sensitivity to area-related costs, while the tracking systems (Figures 13, 14, and 15) show only a moderate sensitivity. This sensitivity increases noticeably as module efficiency decreases, however. In general, area-related BOS costs are not as important a system cost driver as are module costs or module efficiency.

E. SENSITIVITY TO INVERTER COST AND EFFICIENCY

Figures 17 and 18 illustrate the relationship between inverter cost and installed system cost. (The concentrator and one-axis tracking systems are not illustrated, but are essentially similar to the two-axis tracking flat-plate system.) These figures demonstrate the allowable cost of improvements in inverter efficiency. For the fixed flat-plate central-station option, a 94% efficient inverter must have an installed price of $0.185/$W_p$ac to be equivalent to the nominal 97% inverter at $0.24/$W_p$ac (in terms of system cost). Similarly, a 1% increase in efficiency may be made at the expense of a 5% to 6% increase in inverter price. This allowable price increase becomes greater with other central-station configurations, as inverter costs are a smaller fraction of total system cost. Thus, system costs are much more sensitive to inverter efficiency than to inverter costs.

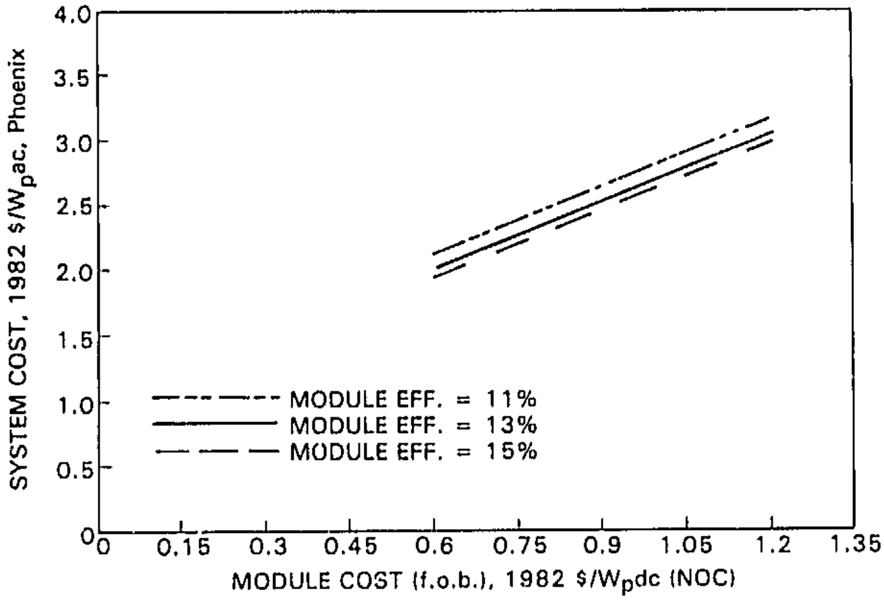

Figure 7. Effect of Module Cost and Efficiency on System Cost: 5-MW Fixed Flat-Plate, Phoenix

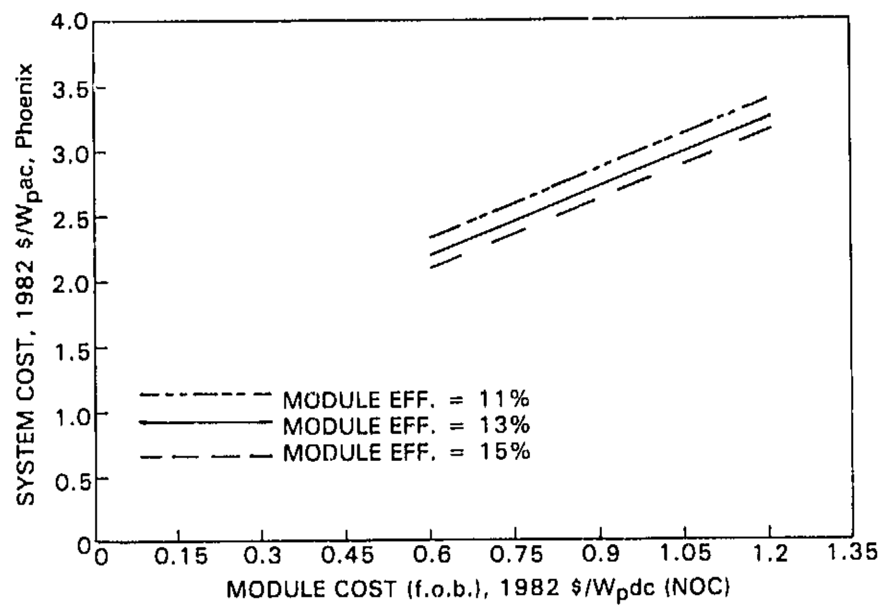

Figure 8. Effect of Module Cost and Efficiency on System Cost: 5-MW Single-Axis Tracking Flat-Plate, Phoenix

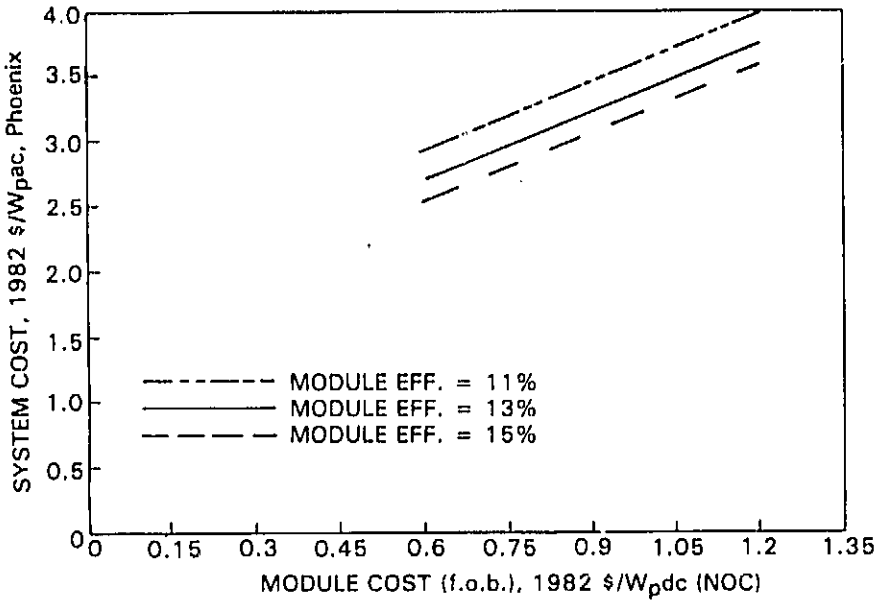

Figure 9. Effect of Module Cost and Efficiency on System Cost: 5-MW Two-Axis Tracking Flat-Plate, Phoenix

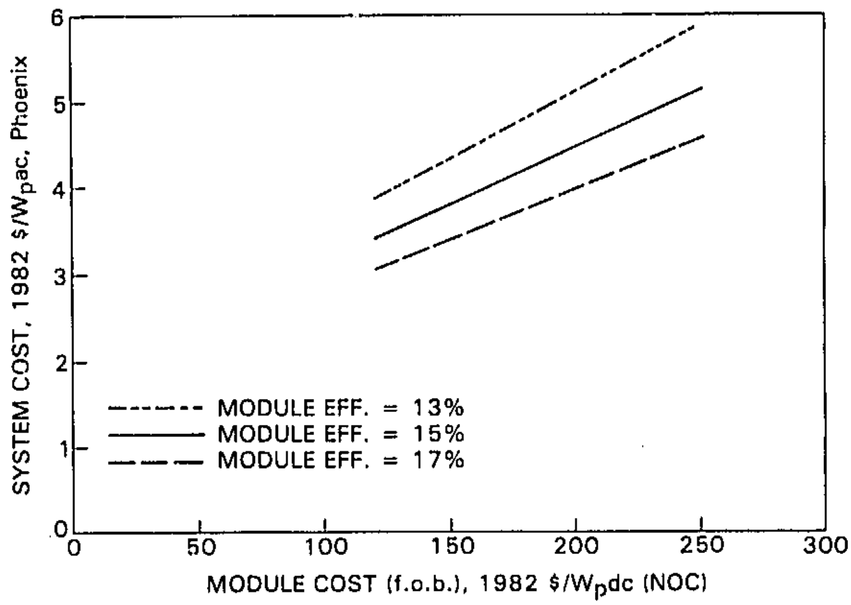

Figure 10. Effect of Module Cost and Efficiency on System Cost: 5-MW Point-Focus Fresnel Concentrator, Phoenix

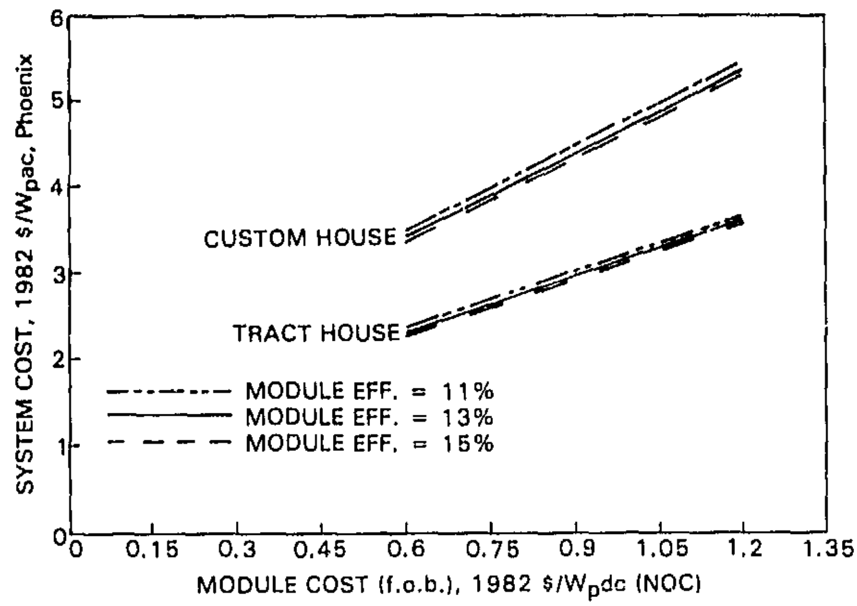

Figure 11. Effect of Module Cost and Efficiency on System Cost: 5-kW Residential (Tract and Custom), Phoenix

Table 27. Equivalent Module Cost and Efficiency Pairs With System Costs Held at Their Projected Value[a]

System	Total Installed System Cost (Phoenix), $\$/W_p\text{ac}$	Module Cost at Various Efficiencies		
		Low Efficiency[b]	Projected[c]	High Efficiency[d]
Flat-Plate				
Fixed	$\$2.45$	$\$0.79/W_p\text{dc}$	$\$0.85/W_p\text{ac}$	$\$0.90/W_p\text{dc}$
Single-Axis Tracking	2.62	$\$0.77/W_p\text{dc}$	$\$0.85/W_p\text{dc}$	$\$0.91/W_p\text{dc}$
Two-Axis Tracking	3.14	$\$0.72/W_p\text{dc}$	$\$0.85/W_p\text{dc}$	$\$0.95/W_p\text{dc}$
Residential				
Tract	2.83	$\$0.82/W_p\text{dc}$	$\$0.85/W_p\text{dc}$	$\$0.87/W_p\text{dc}$
Custom	3.29	$\$0.83/W_p\text{dc}$	$\$0.85/W_p\text{dc}$	$\$0.86/W_p\text{dc}$
Concentrator	3.80	$\$116/m^2$	$\$150/m^2$	$\$184/m^2$

[a]Module costs are given in 1982 $ f.o.b. Module efficiencies are given at NOC; concentrator efficiencies are net of module packing factor, optical efficiency, and tracking error.

[b]11%, except for the concentrator, which is 13%.

[c]13%, except for the concentrator, which is 15%.

[d]15%, except for the concentrator, which is 17%.

F. SENSITIVITY TO MODULE MARKUP AND SYSTEM INTEGRATION FEE

The sensitivity of residential system costs to marketing and integration fees has been highlighted in this report by the inclusion of separate custom-built and tract-house system categories. Clearly, the high indirect charges and markups experienced during custom construction can drastically effect the total cost of installed residential PV systems (Table 26). The same effects are illustrated here (Tables 28 to 31) for ground-mounted systems. As these figures reveal, the cost of larger systems is also quite sensitive to module and system markups, although the effects do not appear as large as those found in the residential case. This smaller effect is the result of a smaller range of uncertainty concerning likely markups on large systems compared with residential-sized installations. The lesson is that standardization and experience can yield important benefits in reducing total system cost of large modular systems by minimizing indirect markups. It is unclear whether such learning and standardization can also be realized in small, residential systems.

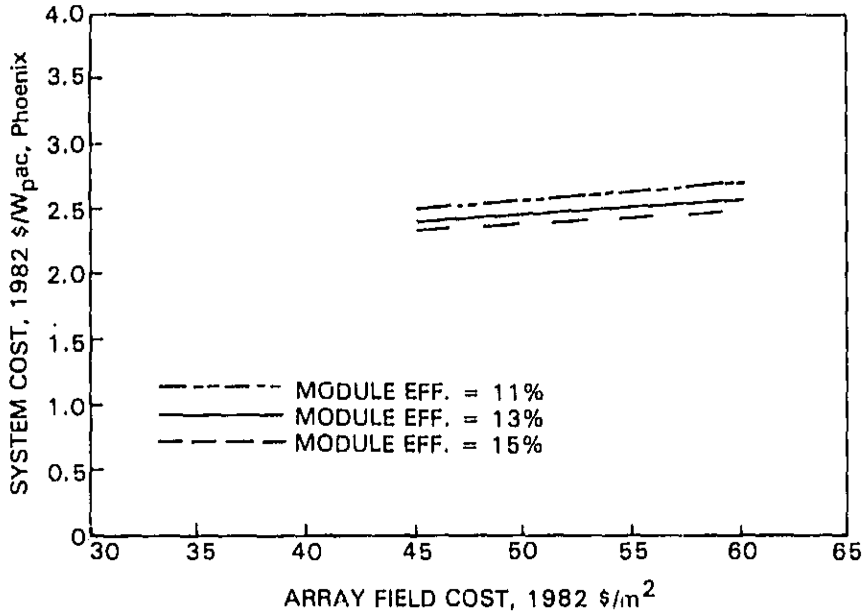

Figure 12. Effect of Array Field Cost on System Cost: 5-MW Fixed Flat-Plate, Phoenix

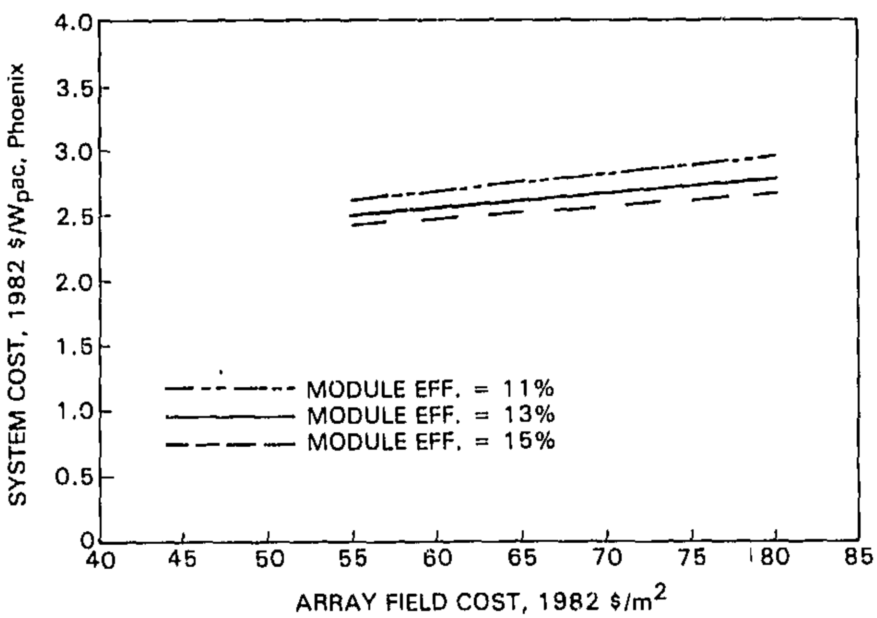

Figure 13. Effect of Array Field Cost on System Cost: 5-MW Single-Axis Tracking Flat-Plate, Phoenix

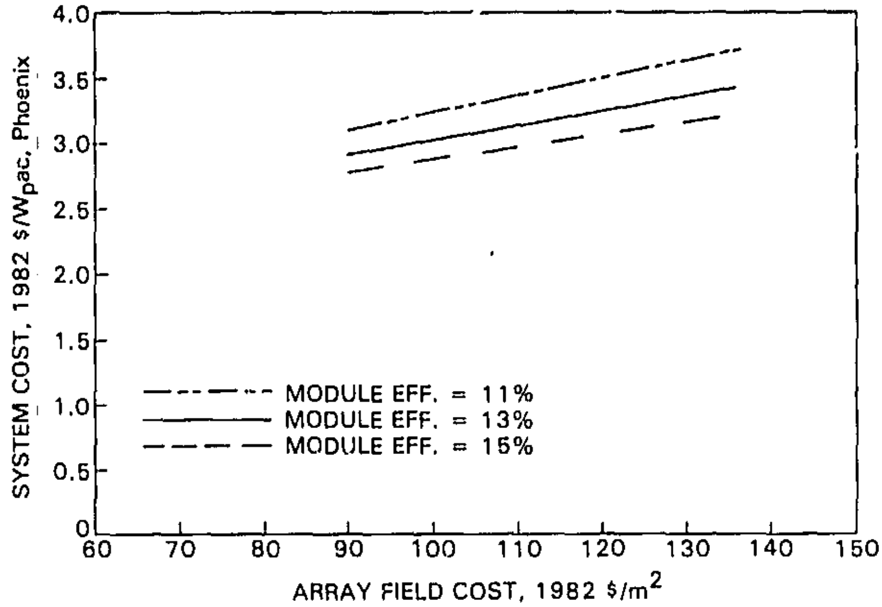

Figure 14. Effect of Array Field Cost on System Cost: 5-MW Two-Axis Tracking Flat-Plate, Phoenix

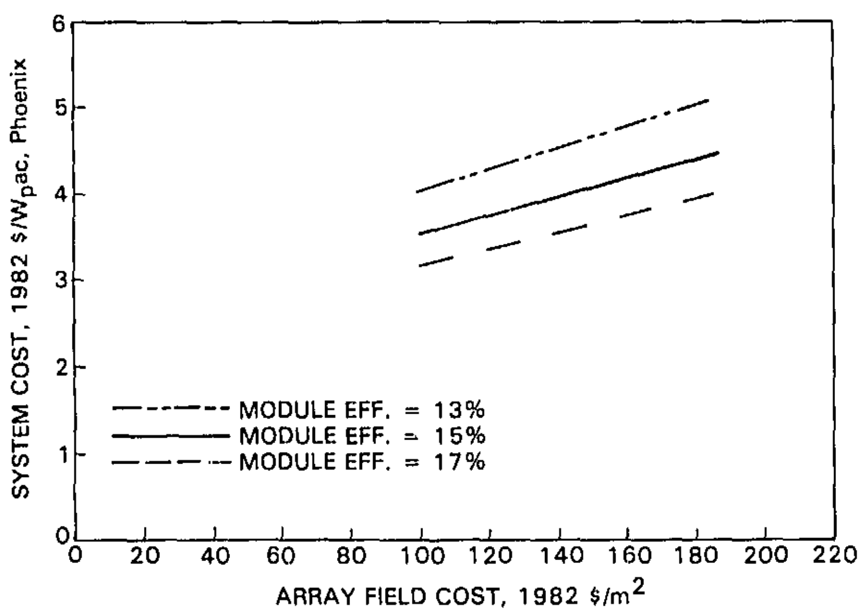

Figure 15. Impact of Array Field Cost on System Cost: 5-MW Point Focus Fresnel Concentrator

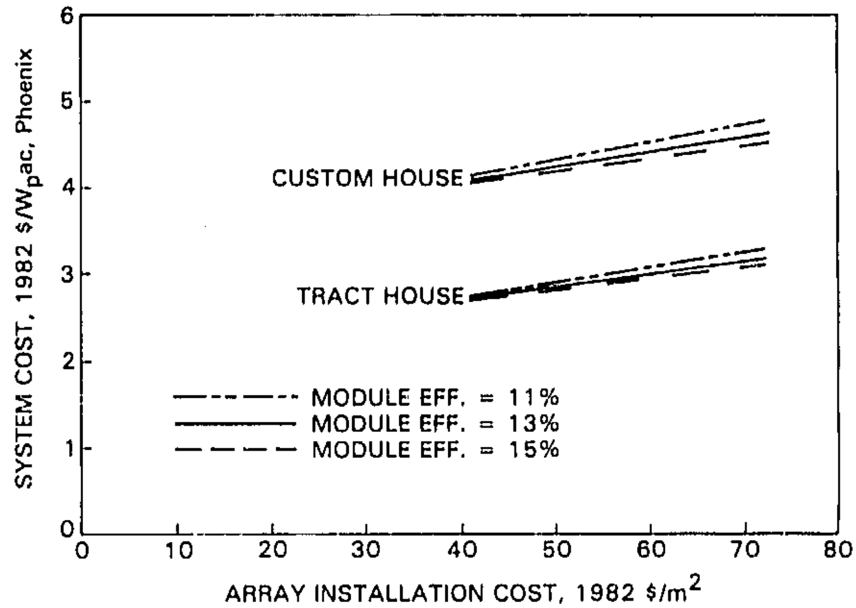

Figure 16. Effect of Array Installation Cost on System Cost: 5-kW Residential (Tract and Custom), Phoenix

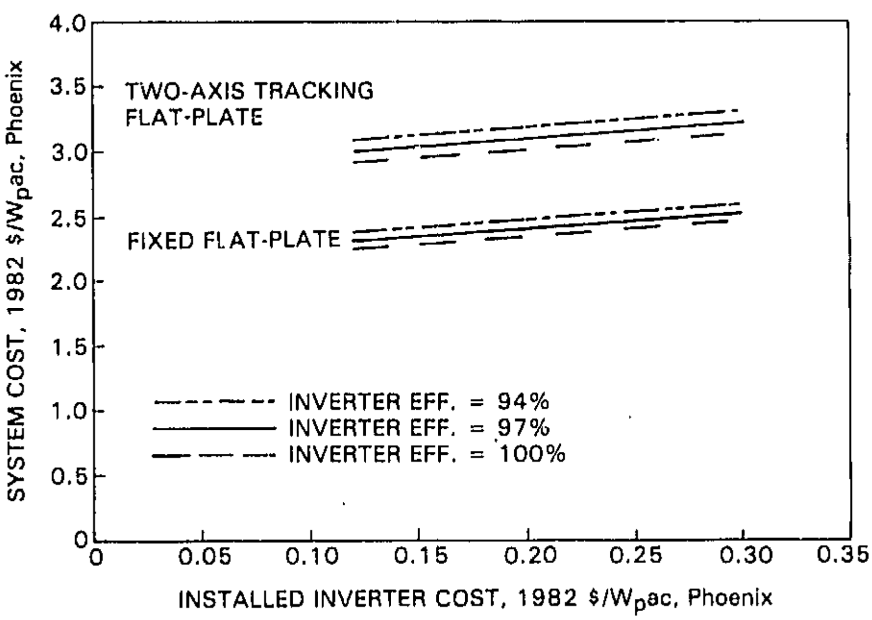

Figure 17. Effect of Installed Inverter Cost on System Cost: 5-MW Fixed and Two-Axis Tracking Flat-Plate, Phoenix

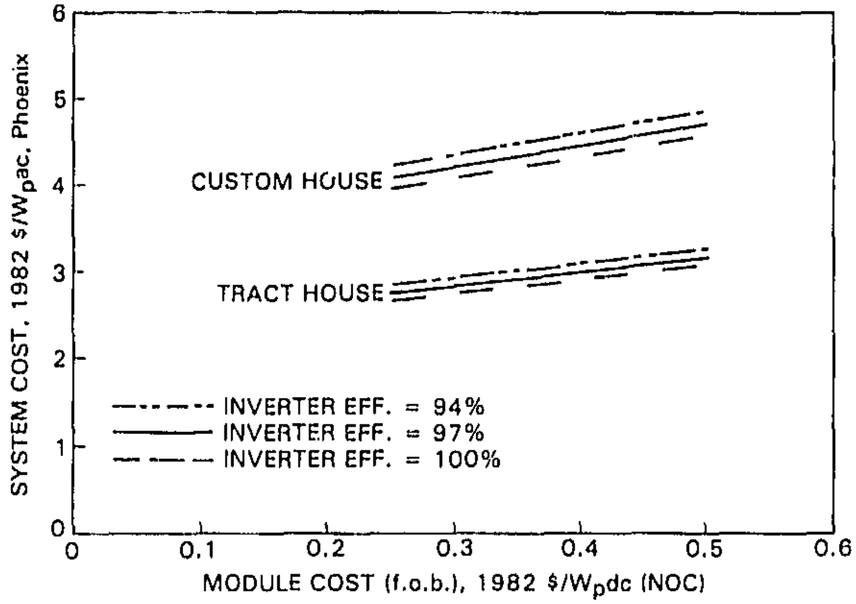

Figure 18. Effect of Inverter Cost on System Cost: 5-kW Residential (Tract and Custom), Phoenix

Table 28. Effect of Integration Fee and Module Markup on System Cost: 5-MW Fixed Flat-Plate, $\$W_{p}ac$

System Integration Fee, %	Module Markup, %			
	0	10	20	30
20	2.12	2.24	2.36	2.48
25	2.20	2.33	2.45	2.58
30	2.29	2.42	2.55	2.68
35	2.38	2.51	2.65	2.79

Table 29. Effect of Integration Fee and Module Markup on System Cost: 5-MW Single-Axis Tracking Flat-Plate, $\$W_{p}ac$

System Integration Fee, %	Module Markup, %			
	0	10	20	30
20	2.28	2.40	2.52	2.64
25	2.38	2.50	2.63	2.75
30	2.47	2.60	2.73	2.86
35	2.57	2.70	2.84	2.97

Table 30. Effect of Integration Fee and Module Markup on System Cost: 5-MW Two-Axis Tracking Flat-Plate, $\$W_{p}ac$

System Integration Fee, %	Module Markup, %			
	0	10	20	30
20	2.78	2.90	3.02	3.14
25	2.89	3.02	3.14	3.27
30	3.01	3.14	3.27	3.40
35	3.12	3.26	3.39	3.53

Table 31. Effect of Integration Fee and Module Markup on System Cost: 5-MW Point-Focus Fresnel Concentrator, $\$W_p ac$

System Integration Fee, %	Module Markup, %			
	0	10	20	30
20	3.33	3.49	3.65	3.80
25	3.47	3.63	3.80	3.96
30	3.61	3.78	3.95	4.12
35	3.74	3.92	4.10	4.28

G. CONCLUSIONS

Module cost (including marketing markups) and engineering and system integration fees seem to have the greatest potential for system cost reduction. These costs not only represent a significant proportion of total system costs, but also are highly uncertain. They are also partially dependent upon market structure and size. Area-related costs are a significant proportion of total costs, but the range of potential area-related costs is not of the same magnitude as module costs or integration fees. Inverter costs, while large in absolute terms, are not as significant to total system costs as these other cost categories. Increases in inverter and module efficiency yield significant benefits, especially in systems with high area-related costs.

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APPENDIX A

ENERGY COST CALCULATIONS

A. INTRODUCTION

Installed photovoltaic (PV) system cost figures do not provide sufficient information for accurate system comparison because they do not account fully for variations in incident insolation, nor do they include operations and maintenance costs. In this report, each system has been rated at site-specific peak conditions, which partially reduces the geographical variation in energy generation among systems with the same rated size. The remaining variation is due to differences either in characteristic energy losses such as electrical and optical degradation rates, shadowing losses and tracking error losses, or in insolation profiles across sites and tracking and concentration options. As an example of this second effect, the peak solar insolation is approximately the same for fixed and tracking flat-plate systems at the same site, but the incident solar energy varies by 20% to 30% (see Table A-1). Table A-2 quantifies the variation in energy production among systems and sites in the form of a capacity factor. Even if site-specific system ratings were to incorporate the effects of degradation and shadowing, as Roger Taylor of the Electric Power Research Institute proposes in Reference A-1, much of the variation shown in Table A-2 would still be present.

Table A-1. Annual Solar Energy to Modules with No Shading, $kWh/m^2 \cdot yr$

System Configuration	Phoenix	Miami	Boston
Fixed Flat-Plate,[a] Latitude Tilt	2384	1797	1377
Single-Axis Tracking[a] Flat-Plate, Horizontal	2740	1967	1506
Two-Axis Tracking[a] Flat-Plate	3047	2105	1675
Two-Axis Tracking Concentrator[b]	2516	1416	1171

[a]The flat-plate insolation figures are probably 5% to 10% low because of the isotropic cloud assumption (Reference A-1).

[b]Direct normal insolation only.

The energy cost calculations presented in this appendix demonstrate a more appropriate method for comparing the costs of PV systems at various sites. The methodology specifically considers site-specific insolation, operations and maintenance (O&M) costs, and each system's average energy conversion efficiency (solar-to-ac electric at the utility distribution feeder, or bus bar). Even so, these energy cost comparisons do not reflect variations through time in the value of electricity (e.g., seasonal or daily variations in the value of a kilowatt hour). In addition, environmental impacts and modularity are ignored.

Table A-2. Levelized System Capacity Factors Including Shading and Levelized Degradation Effects[a]

System Configuration	Phoenix	Miami	Boston
Ground-Mounted (5-MW$_p$ac)			
Fixed Flat-Plate, Latitude Tilt	0.27	0.23	0.21
Single-Axis Tracking Flat-Plate No Latitude Tilt	0.30	0.25	0.23
Two-Axis Tracking Flat-Plate	0.33	0.26	0.25
Two-Axis Tracking Concentrator (Silicon)	0.31	0.23	0.22
Roof-Mounted (5-kW$_p$ac)			
Tract or Custom House	0.27	0.23	0.21

[a]Capacity factors are defined as:

$$\text{capacity factor} = \frac{\text{levelized annual energy}}{\text{rated power output} \times 8760 \text{ hours}}$$

$$\text{levelized annual energy} = \text{array area} \times \text{annual isolation} \times \text{average module efficiency} \times \text{average BOS efficiency} \times \text{levelized degradation factors}$$

This appendix calculates bus-bar energy costs for three ground-mounted flat-plate systems, a ground-mounted concentrator system, and a roof-mounted residential system with two construction scenarios (tract house and custom house). Each is evaluated at three geographic locations: Phoenix, Arizona; Miami, Florida; and Boston, Massachusetts.

B. METHODOLOGY

A system's bus-bar energy cost is obtained by calculating annual system cost (after taxes and in nominal or current year dollars) and dividing by the system's annual energy output. The resulting nominal energy cost may then be converted to a real bus-bar energy cost (in constant dollars).

Annual energy output is the product of annual solar insolation, array area, and average system efficiency (see Equation 1). Solar insolation varies with each site and with the system configuration (see Table A-1). Average annual module and balance-of-system (BOS) efficiencies are multiplied to obtain the system efficiency. Degradation effects are included by calculating an annual (or levelized) degradation factor. Finally, the annual cost of the PV system depends not only upon the installed system cost, but also upon costs of operating and maintaining the system.

Equation 2 gives the formula for deriving annual system cost. It consists of the sum of two terms: a capital recovery term and an annual O&M expenditure. Equation 3 converts this to a cost per kWh, and Equation 4 converts to constant or real dollars. It is on the basis of this real bus-bar energy cost calculated in Equation 4 that PV systems can be accurately compared. Definitions of the fixed charge rate (FCR), capital recovery factor (CRF), and escalation factor (G) are given below (Tables A-4 and A-5) for utility-owned and residential PV systems.

$$\text{annual energy} = \text{annual insolation} \times \text{array area} \times \text{annual average system efficiency} \qquad (1)$$

$$\text{annual cost} = \text{FCR} \times \text{capital investment} + (\text{G} \times \text{CRF}) \times \text{annual O\&M costs (constant \$)} \qquad (2)$$

$$\text{nominal bus-bar energy cost} = \text{annual cost} \div \text{annual energy} \qquad (3)$$

$$\text{real bus-bar energy Cost} = \text{nominal bus-bar energy cost} \div (\text{G} \times \text{CRF}) \qquad (4)$$

C. GROUND-MOUNTED SYSTEMS

Each of the ground-mounted photovoltaic systems evaluated here, three flat-plate and a concentrator, is rated at $5MW_p ac$ under site-specific peak conditions (see Table 19). As shown in Table 20, the required array area varies across sites and system designs. These required aperture areas were calculated according to the equation:

$$\text{aperture area} = \text{rated peak} \quad (1/\ _{NPOC}) \quad (1/\ _{NPOC}) \quad (1/\ _{BOS})$$

where peak insolation (I_{NPOC}) is found in Table A3, peak module efficiency is obtained from the Equation 5:

$$_{NPOC} = \ _{NPOC} \quad 1 - \frac{0.005}{^{o}C} \left[(T_{NPOC} - 20^{o}C) + \frac{30^{o}C}{kW/m^2} (I_{NPOC} - 0.8) \right] , \qquad (5)$$

and peak BOS efficiency ($_{BOS}$) is 93% for the 5-MW systems and 86% for the 5-kW systems.

System performance parameters for ground-mounted systems are given in Table A-3. The average annual module (or collector) efficiency varies with the ambient temperature and insolation profile of each site. Annual collector efficiencies for the flat-plate systems were taken from a recent JPL report (Reference A-3). Site-specific concentrator efficiencies were not available; therefore, an Albuquerque value is used for all three sites (Reference A-4). The BOS efficiency figures are only estimates and may be optimistic.

The ground-mounted systems are assumed to be utility-owned and -operated, subject to utility tax law. Recent experience suggests that a 5-MW array field can be installed and operational in less than a year[1]. Therefore, capital investment and investment tax credits are assumed to be available in the same year as system installation. Energy generation and system depreciation begin the following year.

System costs are set at the 1990 values projected in this study. Operations and maintenance costs are assumed to vary proportionally with array area, as shown in Table A-3. Table A-4 outlines the financial assumptions used in this analysis. For a detailed discussion of the derivation of the location-specific fixed charge rates, see Reference A-4.

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[1]The $1\text{-}MW_p$ ARCO plant at Hesperia, California, required less than a year to design and install.

Table A-3. Central Station Bus-Bar Energy Cost Calculations: PV Performance Parameters

System Parameter	Fixed Flat-Plate	One-Axis Tracking Flat-Plate	Two-Axis Tracking Flat-Plate	Two-Axis Tracking Concentrator (Silicon)
Annual O&M Cost, 1982$/m^2$	1.2	1.5	1.8	1.8
Annual BOS Efficiencies, %				
Inverter	96	96	96	96
Wiring & Mismatch	96	96	95.5	95.5
Parasitic Power (tracking)	--	99.8	99.5	99.5
Dirt Losses	99	99	99	99
Degradation[a] (levelized)				
Electrical	96	96	96	96
Optical	--	--	--	98
Shading Losses	99	99	98	96
Total BOS (levelized)	0.867	0.865	0.850	0.816
Collector Efficiency, %[b]				
Phoenix	12.4	12.4	12.4	15.2
Miami	12.3	12.3	12.3	15.2
Boston	13.0	13.0	13.0	15.2

[a]The levelized electrical degradation figure is based on an annual electrical degradation rate of 0.5%. The annualized optical degradation figure implies annual degradation of 0.25%.

[b]The collector efficiency is an average annual efficiency that is isolation and temperature-corrected based upon Nominal Operating Cell Temperature (NOCT) of 46°C for both flat-plate and concentrator modules, and a flat-plate module fill factor of 0.70

Table A-4. Central Power Station Bus-Bar Energy Cost Calculation: Financial Parameters

Parameter	Symbol	Boston	Miami	Phoenix
System Lifetime (years)	N	30	30	30
Inflation Rate	g	0.06	0.06	0.06
Nominal Discount Rate	k	0.11	0.11	0.11
Federal Tax Rate	f	0.46	0.46	0.46
State Tax Rate	s	0.095	0.05	0.105
Combined State and Federal Tax Rate[a]	TR	0.5113	0.4870	0.4922
Investment Tax Credit[b]	ITC	0.10	0.10	0.094
Insurance Fraction	B2	0.01	0.01	0.01
Property Tax Rate (on undepreciated balance)	B1	0.0281	0.0273	0.025
Depreciation Factor[c] (15-year)	DPF	0.4762	0.4762	0.4762
Capital Recovery Factor[d]	CRF	0.1150	0.1150	0.1150
Fixed Charge Rate[e]	FCR	0.1575	0.1757	0.1707
Escalation Factor[f]	G	15.88	15.88	15.88

[a] Combined tax rates are calculated as (s + f - 2 sf)/(1 - sf) for Phoenix and s + f - sf for Miami and Boston. In Arizona, Federal tax payments are deductible on state tax returns; in Miami and Boston they are not deductible.

[b] In Arizona, the effect of the Federal investment tax credit is to increase state taxes owned, because Federal tax payments are deducted from state tax returns. The procedure used to incorporate this effect is an adjustment to the Federal investment tax credit as follows:

$$ITC = ITC \times (1 - (s - sf)/(1 - sf))$$

[c] The depreciation factor is reduced by 5% in accordance with the Tax Equity and Fiscal Responsibility Act of 1982.

[d] $$CRF = 1 - \frac{k}{(1 + k)^N}$$

[e] The fixed charge rate is defined as:

$$FCR = CRF \left(\frac{1 - TR \times DPF - ITC}{(1 - TR)} \right) + \overline{B1} + B2,$$

where $$\overline{B1} = B1 \times CRF \times \sum_{t=1}^{15} \left[1 - \sum_{s=1}^{t} dep(s) \right] \left(\frac{1}{1 + k} \right)^{t-1}$$

Dep(s) are the 15 annual depreciation rates given in the tax code, and it is assumed that property taxes are paid on the undepreciated balance.

$f_G = (1 + g)/(k - g)\ )\quad (\ 1 - (1 + g/1 + k)^N$

D. RESIDENTIAL SYSTEMS

Residential roof-mounted systems are assumed to be privately owned. For tax purposes, these systems are considered either as business or non-business investments. With a business classification, the investment can be depreciated and the 10% Federal investment tax credit applies. In this case, bus-bar energy costs are derived in the same manner as for ground-mounted systems. However, the fixed charge rates have different values because of different tax rates. With a non-business classification, the 10% Federal investment tax credit and deductions for O&M expenditures do not apply. The FCR rate depends only on the capital recovery factor and insurance and property tax expenses. Table A-5 lists the financial parameters used in calculating bus-bar energy costs for residential systems. Table A-6 derives the fixed charge rates for both the business and non-business cases. Note that the Fixed Charge Rates for business and non-business classification of residential systems do not differ significantly. For this reason, the distinction is not relevant and only one set of residential bus-bar energy costs is presented, which is applicable to both classifications. Table A-7 gives the system parameters for the residential system. Insolation values are found in Table A-1 under the fixed flat-plate option, and required array area is found in Table A-8.

Table A-5. Residential Bus-Bar Energy Cost Calculation: Financial Parameters

Parameter	Symbol	Boston	Miami	Phoenix
System Lifetime, years	N	30	30	30
Inflation Rate	g	0.06	0.06	0.06
Nominal Discount Rate	k	0.11	0.11	0.11
Marginal Federal Tax Rate	f	0.28	0.28	0.28
Marginal State Tax Rate (Phoenix, Miami, Boston)	s	0.05	--	0.08
Combined State and Federal Tax Rate[a]	TR	0.3160	0.28	0.3224
Investment Tax Credit[b]	ITC	0.10	0.10	0.094
Property Tax Rate[c]	B1	0.02727	0.025	0.025
Property Tax Exemption, years	y	20	10	3
Insurance Fraction	B2	0.01	0.01	0.01
Depreciation Factor[d] (five-year)	DPF	0.6937	0.6937	0.6937
Capital Recovery Factor	CRF	0.1150	0.1150	0.1150
Escalation Factor	G	15.88	15.88	15.88

[a]Combined tax rates are calculated as $(s + f - 2\ sf)/(1 - sf)$ for Phoenix and $s + f - sf$ for Boston. In Arizona, Federal tax payments are deductible on state tax returns; in Boston they are not. Florida does not have personal income taxes.

[b]In Arizona, the effect of the Federal investment tax credit is to increase state taxes owed, because Federal tax payments are deducted from state tax returns. The procedure used to incorporate this effect is an adjustment to the Federal investment tax credit: $ITC = ITC \times (1 - (s - sf)/(1 - sf))$.

[c]This is the property tax rate in those years the PV system is not exempted.

[d]The depreciation factor is reduced by 5% in accordance with the Tax Equity and Fiscal Responsibility Act of 1982.

Table A-6. Residential Bus-Bar Energy Cost Calculation: Fixed Charge Rate

Location	Property Tax Exemption, years	$\overline{B1}$	Fixed Charge Rate Tax Treatment[a]	
				Non-Business
Boston	20	0.002	0.127	0.127
Miami	10	0.008	0.131	0.133
Phoenix	3	0.018	0.143	0.143

[a]When the PV system is treated as a business, the residential fixed charge rate is defined as:

$$FRC = CRF \quad \frac{1 - TR\ DPF - ITC}{1 - TR} + \overline{B1} + B2.$$

When the PV system is not treated as a business, the residential fixed charge rate is defined as:

$$FCR = CRF + \overline{B1} + B2.$$

In both cases, the term $\overline{B1}$ is given by:

$$\overline{B1} = B1 \quad \frac{1}{k}(1 - (\frac{1}{1+k})\ )^{n-y} \ (\frac{1}{1+k})^{y} \quad CRF$$

Symbols are defined in Table A-5.

Table A-7. Residential Bus-Bar Energy Cost Calculations: System Parameters

System Parameter	Value
O&M Cost, $/m^2 (1982$)	1.2
Annual Efficiencies, %	
Inverter	92
Wiring & Mismatch	95
Dirt Losses	99
Electrical Degradation[a] (levelized)	96
Total BOS (levelized)	83
Average Annual Collector Efficiency[b], %	
Phoenix	12.1
Miami	12.0
Boston	12.7

[a]The annualized degradation figure is based on a yearly decrease in system energy output of 0.5%.

[b]Includes a 97.5% correction factor for higher operating temperature associated with integral-mounted systems.

E. RESULTS

Projected installed system costs are presented in Table A-9. Corresponding bus-bar energy costs and cost ranges implied by these projected system costs are given in Table A-10 for three U.S. locations: Phoenix, Miami, and Boston.

This appendix provides one set of bus-bar energy cost calculations. This analysis is not intended as an argument in favor of one system over another. The methodology presented in this appendix does allow comparison of disparate PV system designs, but such an analysis is limited by the uncertainty surrounding key assumptions, in particular the uncertainty inherent in PV system cost and performance projections. Currently, uncertainties are too great to select a preferred technology with confidence, especially because the projected differences among systems revealed here are not great.

Table A-8. Installed 1990 System Cost Projections and Ranges[a], 1982 $

System	Projected System Costs,	Projected System Cost, $/W_pac		
	$/m^2 + $/Wpac	Phoenix	Miami	Boston
Ground-Mounted (5-MW$_p$ac)[b]				
Flat-Plate				
Fixed	233 + 0.34	2.45	2.78	3.13
	(160-358) (0.17-0.47)	(1.62-3.72)	(1.85-4.22)	(2.08-4.75)
One-Axis Tracking	252 + 0.34	2.62	2.98	3.35
	(172-387) (0.17-0.47)	(1.73-3.98)	(1.97-4.53)	(2.23-5.10)
Two-Axis Tracking	309 + 0.34	3.14	3.58	4.04
	(214-464) (0.17-0.47)	(2.11-4.68)	(2.41-5.33)	(2.73-6.02)
Concentrator				
Planar Silicon	393 + 0.34	3.80	4.76	5.50
	(286-614) (0.17-0.47)	(2.69-6.62)	(3.38-8.32)	(3.93-9.64)
Roof-Mounted (5-kW$_p$ac)				
Tract House	218 + 0.70	2.83	3.17	3.52
	(128-382) (0.48-1.22)	(1.73-4.96)	(1.93-5.55)	(2.14-6.16)
Custom House	329 + 1.00	4.22	4.73	5.26
	(185-606) (0.64-1.90)	(2.45-7.83)	(2.74-8.77)	(3.03-9.74)

[a]Ranges appear in parentheses.
[b]These are site-specific peak power ratings based on EPRI's nominal peak operating conditions.

Table A-9. Required Array Aperture Area

	Required Aperture Area, m^2		
	Phoenix	Miami	Boston
5-MW$_p$ac Systems			
Flat-Plate[a] (13% at NOC)			
Fixed	45,300	52,400	59,800
Single-Axis Tracking	45,300	52,400	59,800
Two-Axis Tracking	45,300	52,400	59,800
Concentrator			
(15% at NOC)	44,000	56,200	65,700
(18% at NOC)	36,800	46,900	54,600
5-kW$_p$ac Systems			
Flat-Plate Residential			
(13% at NOC)	48.9	56.7	64.7

[a]The peak operating conditions for fixed flat-plate systems at latitude tilt are also used for the tracking flat-plate systems.

Table A-10. 1990 Real Bus-Bar Energy Cost Projections[a], 1982 $

System	Real Bus Bar Energy Cost, $/kWh Phoenix	Miami	Boston
Ground Mounted ($5MW_pac$)			
Fixed Flat-Plate	0.103 (0.070-0.154)	0.139 (0.095-0.208)	0.153 (0.104-0.228)
Single-Axis Tracking Flat-Plate	0.097 (0.066-0.145)	0.138 (0.094-0.206)	0.152 (0.104-0.226)
Two-Axis Tracking Flat-Plate	0.106 (0.073-0.156)	0.158 (0.109-0.231)	0.167 (0.116-0.244)
Two-Axis Tracking Concentrator (Planar Silicon)	0.135 (0.097-0.231)	0.242 (0.175-0.416)	0.261 (0.192-0.448)
Roof-Mounted ($5\text{-}kW_pac$)			
Tract House (Business and Non-Business)	0.100 (0.063-0.171)	0.120 (0.076-0.206)	0.139 (0.088-0.236)
Custom House (Business and Non-Business)	0.146 (0.087-0.267)	0.176 (0.105-0.321)	0.203 (0.120-0.369)

[a]Ranges in parentheses.

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A-2. Taylor, R., System Status Assessment: An Integrated Perspective, Special report (draft), Electric Power Research Institute, Palo Alto, California, September 1982.

A-3. Jones, G.J., "Energy Production Trade-Offs in Photovoltaic System Design," SAND82-2239, Sandia National Laboratories, Albuquerque, New Mexico, April 1983.

A-4. Gonzales, C.C., and Ross, R.G., Jr., "Energy Prediction Using NOCT-Based Photovoltaic Reference Conditions," presented at the 1983 Annual American Solar Energy Society Conference in Minneapolis, Minnesota, June 1-3, 1983.

A-5. Borden, C., "Fixed Charge Rates for Flat-Plate and Concentrator PV System Cost Analysis," JPL IOM 311-3-188/6352B, Jet Propulsion Laboratory, Pasadena, California, March 1982.

APPENDIX B

MODULE RATINGS

Table B-1 presents the conditions under which modules are rated with respect to their direct-current output for four rating schemes. These conditions differ in the amount of insolation applied to the module and the temperature at which the module is operated. Note that NOC and SOC rate the module at a fixed ambient temperature and wind speed as opposed to a fixed cell temperature, allowing modules that naturally shed heat better (operate at lower temperatures) to reflect this advantage in their rated output. None of these ratings is site-specific.

Table B-1. Operating Conditions Used to Characterize Solar Cell Modules: Current Usage

		Operating Conditions			
	Units	STC (American)	STC (European)	NOC	SOC
Insulation[a]	W/m^2	1000	1000	800	1000
Spectrum	AM	1.5	1.5	1.5	1.5
Cell Temperature	°C	28	25	NOCT	NOCT
Nominal Operating Cell Temperature (NOCT)					
Insolation[a]	W/m^2	-	-	800	800
Ambient Temperature	°C	-	-	20	20
Wind Velocity	m/s	-	-	1	1

STC - Standard test conditions (previously peak operating conditions)
NOC - Nominal operating conditions
SOC - Standard operating conditions (consistent with SERI's reference design conditions)

[a]Total irradiance if applied to a flat-plate module and direct irradiance if applied to a concentrator module.