CR 173,205

5220-19
Photovoltaics Program
Technology Development and Applications
Lead Center

DOE/ET-20356-8
Distribution Category 63

The Value of Residential Photovoltaic Systems: A Comprehensive Assessment

C.S. Borden

September 15, 1983

Prepared for
U.S. Department of Energy
Through an Agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

JPL Publication 83-63

5220-19
Photovoltaics Program
Technology Development and Applications
Lead Center

DOE/ET-20356-8
Distribution Category 63

The Value of Residential Photovoltaic Systems: A Comprehensive Assessment

C.S. Borden

September 15, 1983

Prepared for
U.S. Department of Energy
Through an Agreement with
National Aeronautics and Space Administration
by
Jet Propulsion Laboratory
California Institute of Technology
Pasadena, California

JPL Publication 83-63

Prepared by the Jet Propulsion Laboratory, California Institute of Technology, for the U.S. Department of Energy through an agreement with the National Aeronautics and Space Administration.

This publication reports on work done under NASA Task RE-152 Amendment 200, DOE/NASA IAA No. DE-AI01-76ET20356.

ABSTRACT

Utility-interactive photovoltaic (PV) arrays on residential rooftops appear to be a potentially attractive, large-scale application of PV technology. Results of a comprehensive assessment of the value (i.e., break-even cost) of utility-grid connected residential photovoltaic power systems under a variety of technological and economic assumptions are presented. A wide range of allowable PV system costs (1$ to $3 per peak watt) are calculated for small (4.34 kW_p ac) residential PV systems in various locales across the United States. Primary factors in this variation are differences in local weather conditions, utility-specific electric generation capacity, fuel types, and customer-load profiles that affect purchase and sell-back rates, and non-uniform state tax considerations. Additional results from this analysis are: locations having the highest insolation values are not necessarily the most economically attractive sites; residential PV systems connected in parallel to the utility demonstrate high precentages of energy sold back to the grid, and owner financial and tax assumptions cause large variations in break-even costs. Significant cost reduction and aggressive resolution of potential institutional impediments (e.g., liability, standards, metering, and technical integration) are required for a residential PV market to become a major electric-grid-connected energy-generation source.

ACKNOWLEDGMENTS

This residential break-even cost study was performed under the guidance of Tom W. Hamilton and Jeffrey L. Smith of the Jet Propulsion Laboratory (JPL) Photovoltaics Technology Development and Applications Lead Center. The considerable analytical support of my JPL colleagues Richard B. Davis, David S. Lamm, Timothy N. Tutt, Karen Hughes, and Lowell H. Orren is gratefully acknowledged. In addition, computer support provided by JPL contractors Jerome V. V. Kasper of Vincent Rae Associates and Michael C. Davisson of Apogee Computer Designs was essential to the successful completion of this study.

CONTENTS

Tables

This Page Intentionally Left Blank

SECTION I

INTRODUCTION AND SUMMARY

Utility-interactive photovoltaic (PV) arrays on residential rooftops appear to be a potentially attractive, large-scale application of PV technology. In view of this, the National Photovoltaics Program has a keen interest in technology development, testing, and assessment of the residential option. This report documents the results of an analysis, initiated in October 1980 and completed in September 1981, that evaluates residential PV system cost effectiveness under a variety of technological and economic assumptions. These results have provided direct input to PV Program evaluations, most recently at a working group meeting for Residential Program Assessment held at the California Institute of Technology, Pasadena, California, on December 14, 1982*.

This report calculates the value of a PV system to a prospective new-home buyer, based on the savings he can expect in purchases of electricity from the utility grid and on revenues from the sale of electricity to the utility (Reference 1). The report does not project the costs of residential PV systems; rather, a case-study approach is used to describe allowable PV system costs (i.e., the system's break-even cost) for residential applications in a variety of locales across the country. For each case, the Lifetime Cost and Performance (LCP) model (Reference 2) simulates PV-system performance, cost and value over the system's operating lifetime, and the Alternative Power System Economic Analysis Model (APSEAM) (Reference 3) translates these into after-tax financial figures of merit. Sensitivity analyses are performed to determine variations in PV system break-even cost due to alternative system designs and sizes, location factors, electric utility grid characteristics, system performance capability changes (i.e., array degradation), recurrent operating costs, and PV system owner financial characteristics (e.g., income level and discount rate). These results are intended to aid the Program in guiding research and development activities through enhanced insight into PV technology performance and market factors in the residential application.

Residential PV systems are small systems (2 kW_p to 10 kW_p) that may be widely dispersed throughout domestic utility grids. Due to their compatibility with residential rooftops, PV arrays can have very low structure costs and can displace some of the costs associated with a conventional roof when built as a part of new-home construction. The PV system cost may

---

*The purpose of this meeting was to assess residential photovoltaics relative to its progress; economics; future cost projections; expected U.S. Department of Energy (DOE) funding; technical and institutional barriers; overall system worth, and the potential of residential PV as a significant energy option to establish a base for refining future residential program direction.

additionally be rolled into the cost of the new home, possibly allowing for relatively favorable financing terms. Retrofitting PV systems to existing roof structures usually suffers additional design and cost constraints. The advantages of residential PV applications, in addition to other applications such as large ground-mounted PV systems, are currently being evaluated by the National Photovoltaics Program. Large ground-mounted PV systems display a number of positive attributes, such as unconstrained fixed-array orientation; the options of tracking flat-plate and concentrator system designs; utility or nonutility ownership; lower expected costs for marketing and distribution of equipment; economies of scale for some power-related costs and for installation; fewer safety-related and damage-hazard problems (e.g., attic fires and roof maintenance); potentially lower module operating temperatures that affect both instantaneous power output and module lifetime, and investors with well-established long-term investment perspectives (i.e., 20-to-50-year life-cycle costing) or favorable financial conditions. Both residential and large ground-mounted systems are considered to be potentially attractive PV system alternatives.

To calculate allowable installed capital costs, some PV system costs must be estimated. The calculated total value of the PV system is, for example, reduced by operations and maintenance expenses, or other recurrent expenses, during system operation. In addition, the dollar credit associated with displacement of conventional roofing materials and labor (i.e., the roof credit) is accounted for in the determination of allowable installed costs. The resulting break-even cost reflects only that of installed PV equipment. Since some portions of the PV system may experience different tax treatments (e.g., varying lifetimes for cost-recovery deductions for structural components versus tangible personal property), preliminary estimates of subsystem costs are required for proportioning elements of the allowable installed system cost.

The generic system design used in this report is a 4.34 kW_p ac array mounted on a residential roof. (Unless dc is specified, all wattage figures in this report are ac.) A new home is considered to be constructed with the roof bearing the array facing south and tilted at the local latitude angle for all locations. Mature PV technology is assumed.* The home with the PV system is purchased and placed in service at the end of 1986 and is assumed to operate for 30 years. The PV system is utility-grid-interactive and energy generated by the PV system is either consumed on-site by the homeowner, sold to the utility, or both. The value of PV-generated electricity to the homeowner is assumed to be determined primarily through the utility rate structure (for purchase and sell-back), which is only an indirect measure of PV system value. There is no battery storage with the PV system. Electricity flows are metered to account for homeowner electricity purchase and sell-back. Electricity sold back to the utility determines the business portion of the

*When this analysis was performed in 1981, the target date for achieving a mature level of technology development was 1986. Today's projections envision a delay in the potential achievement of low-cost ($40/m^2 to $75/m^2, 1982 $), high-efficiency (13% to 17% at 28 °C and at AM1.5), long-life (30-year) flat-plate PV modules until the 1990s (Reference 4).

investment for tax purposes. The financial analysis includes a variety of tax treatments for costs and revenues. Federal and state solar-energy tax credits are excluded from the baseline assumptions, but are evaluated in the sensitivity analysis. It is assumed in this report that the homeowner has the option to defer purchase of the PV system, (i.e., he can choose to buy a non-PV house).

The value of a PV system to a representative homeowner at the time of the purchase decision is computed from a number of technical, geographic and economic factors. These include projections of PV technology performance, site-specific weather conditions, utility rate structures at the time of the PV installation and beyond, utility interconnection requirements, homeowner load (if part of the load is to be satisfied with PV output), PV system operations and maintenance costs and procedures, owner-dependent financial environment, and general economic conditions over the relevant financial time frame. PV system value is expressed in terms of a break-even cost, which is defined as the maximum allowable purchase price that a potential buyer could pay for a PV system without losing money; that is, the purchase price in dollars per kilowatt of installed capacity that equates the net present value of the PV investment to zero.

The break-even cost approach is useful in a homeowner's making an investment decision, since it contains all of the pertinent technical and owner-specific financial characteristics of the investment, and collapses this information to a single, discounted, after-tax amount. By assumption, the homeowner requires the PV system to be financially viable, with a positive net present value, for investment to occur. His purchase decision is not affected by any measures that are not translatable into dollars (e.g., personal status, environmental considerations or true hobby use of PV systems). Although supplemental financial figures of merit would probably be used by a potential PV purchaser (e.g., return on investment or payback period) for his investment decision, the break-even cost is considered the most realistic single-number description of the value of a PV system for the purpose of a technology development program seeking to set and evaluate cost and performance targets.

Estimated PV system break-even costs (expressed in 1980 $\$/W_p$ ac) for a number of sites across the United States are presented in Figure 1. (See Appendix B for a description of the site selection strategy.) Baseline assumptions for the results shown in the figure are: PV interconnection is in parallel with the utility (i.e., homeowner load is served before sell-back of remaining PV output to utility); modules are mounted integral to the roof; sell-back revenues are treated as income; standard business deductions are applicable (as a ratio of energy sold back to the utility to the total energy generation); and annual homeowner income is $40,000 in 1980 dollars.

Baseline results displayed in Figure 1 demonstrate a wide range of allowable residential PV system costs (1$ to $3 per peak watt) in various locales across the country. Primary factors in this variation are differences in local weather conditions; utility-specific electric generation capacity, fuel types, and customer load profiles that affect purchase and sell-back rates; and non-uniform state tax considerations. Additional results from this analysis are: locales having the highest insolation values are not necessarily the most economically attractive sites (e.g., Phoenix); residential PV systems connected in parallel to the utility demonstrate high

Figure 1. Photovoltaic Residential System Break-even Costs (1980 $/$W_p$ ac)

percentages of energy sold back to the grid, and owner financial and tax assumptions cause large variations in break-even costs (including the relative worth of PV as a tax shelter). Figure 1 shows that in locales where there are both high annual insolation levels and high cost of electricity generation (primarily due to oil-based generation), cost-effective applications require systems of total costs less than $\$3.30/W_p$ ac. Significant cost reduction and aggressive resolution of potential institutional impediments (e.g., liability, standards, metering, and technical integration) are required for a residential PV market to become a major electric-grid-connected energy-generation source.

Sensitivity analyses have been performed on several key parameters that affect PV system break-even costs. Variations in PV system break-even costs resulting from different PV-utility modes of interconnection (e.g., either sell back all PV output or sell back only excess output over homeowner load); tax treatment (e.g., losses from system operation may or may not be applied against other sources of income, revenues may be treated as energy consumption offset rather than as income for tax purposes, and investment tax credit may or may not apply); homeowner financial characteristics (e.g., income level and discount rate); PV system financing attributes; utility rate structures; state tax laws; and recurrent expenditures, are determined. The effect of varying PV system size is estimated, as is the effect of alternative rates of array electrical degradation. A comparison of break-even costs of different roof-mounting designs and roof credits is presented. Federal and state solar-energy incentives are evaluated in the analyses, as are tax credits, property-tax exemptions and the effects of expensing PV equipment.

This report is intended to highlight the results of technical and economic sensitivity analyses for residential PV systems. Section II summarizes the approach, assumptions and limitations of the analysis. Base-case results and sensitivities to financial assumptions, PV system descriptions, and government incentives are presented in Section III. A description of the economic assessment approach is presented in Appendix A. Baseline descriptions of the PV system design, cost and performance, and utility-related and locale-related factors are discussed in Appendix B. Detailed economic factors and assumptions regarding the methodology and base-case inputs are presented in Appendix C.

N.B.: Except where otherwise specified, all dollar figures used in this report are expressed in 1980 dollars.

This Page Intentionally Left Blank

SECTION II

APPROACH, ASSUMPTIONS AND LIMITATIONS

A. APPROACH

To identify a probable range of allowable costs for residential PV systems, a generic array design has been postulated and variations in locale, electric utility, financial, and system design and operating characteristics are evaluated. The National Photovoltaics Program Technology Development and Applications Lead Center has developed a methodology for synthesizing this information into break-even costs (i.e., the maximum allowable installed system cost per watt).* At the break-even cost, the net present value of the investment is defined as zero. This means that all costs associated with the PV system (construction, operations and maintenance, taxes etc.) including a competitive rate of return on the investment, are completely covered by after-tax revenues over the lifetime of the system. If the calculated allowable installed price (or less) can be achieved by the PV industry, profitable investment in residential PV systems by homeowners may occur.**

Figure 2 illustrates the flow of information used in Program economic analyses for distributed PV systems.*** Two models are displayed in the figure: the Lifetime Cost and Performance Model for Distributed PV Systems (LCP), and the Alternative Power Systems Economic Analysis Model (APSEAM). As depicted within the dashed box, LCP simulates PV system performance by time of day and over the system's operating lifetime, calculates system initial and recurrent costs, incorporates energy use with respect to time-of-day homeowner load and sell-back to the utility, and determines the before-tax dollar value

*When evaluating nonutility-owned, grid-connected residential PV systems, this analysis assumes that current and projected homeowner rates for electricity purchase represent the homeowner's valuation of avoided energy consumption, and sell-back rates set by the utility under the Public Utilities Regulatory Policies Act of 1978 (PURPA) (Reference 5) or avoided fuel costs by time of day, if PURPA-based rates are not available, represent the utility's basis for valuing PV output. In the case of utility ownership of the PV system, utility simulation models that can perform capacity expansion and production costing estimates are required for an accurate estimate of value.

**Break-even cost estimates for distributed PV systems have been made by other organizations (e.g., Sandia National Laboratories and the Electric Power Research Institute). Variations in break-even cost estimates between organizations arise from differences in both methodology and assumptions.

***This figure is first presented in Introduction to PV Program Price Goals, T.W. Hamilton, JPL Internal Memorandum 040-LC, June 1980. The LCP-APSEAM models described here were originally developed by the PV Lead Center to assist in the establishment of PV system price goals.

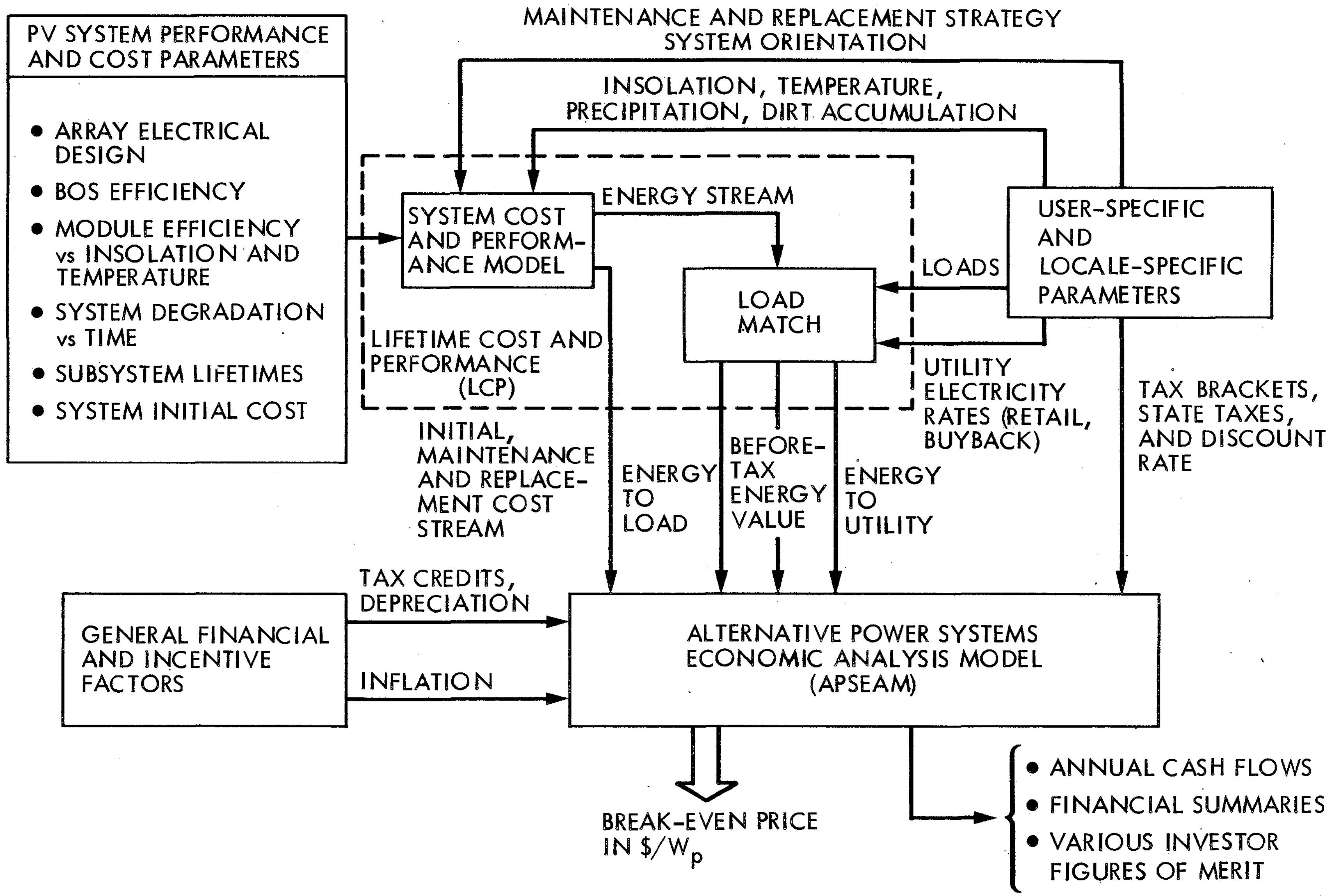

Figure 2. Distributed PV System Economic Analysis Methodology

of energy generation for a wide variety of systems and applications. The resulting outputs from the LCP simulation are described in terms of energy and pretax cash flows over time. This information is then combined with other financial descriptions affecting the PV system owner and is evaluated in the APSEAM financial analysis model. APSEAM determines the PV system owner's after-tax cash flows during the relevant financial time frame. The primary bottom-line financial descriptor resulting from this model is the system break-even cost.* This value is derived from a procedure that evaluates residential PV ownership cost-effectiveness by comparison with the alternative of purchasing electricity from the grid and not buying the PV system. The formulation of PV system performance and financial analysis illustrated in Figure 2 provides a useful tool for understanding the value of PV systems and performing economic and system design tradeoffs.

Nine locales have been selected for assessment of residential PV systems. (The selection procedure is described in Appendix B, Section IV.) These locales form the basis of the assessment of the potential for residential PV systems in different areas due to varying climates, utility costs of electricity generation, and state tax considerations. A case-study approach is used to establish first the locale-specific target break-even cost for a baseline set of assumptions. Then sensitivities are performed for alternative metering configurations, roof-mounting techniques, homeowner financial assumptions, operation and maintenance strategies, and government incentives. Data collection for these locales proceeded under the premises that data should be correlated to the greatest extent possible (e.g., weather data and utility customer residential load data should be based on the same time period); should be conservative, e.g., avoided fuel costs only are used as a proxy to PURPA-mandated avoided costs (see first footnote on p. 7) for sell-back when sell-back rates were not available from the utility; and should be based on empirical data whenever practical (e.g., system energy output reduction due to dirt accumulation).

B. ASSUMPTIONS

Residential PV system design, utility interface, and economic assumptions are discussed in this section to facilitate interpretation of results. Additional details and a comprehensive set of inputs are shown in the appendices to this report.

1. Residential PV System Design

Roof-mounted flat-plate PV arrays are the assumed baseline residential PV system design. The system is owned by the homeowner, and it is

*Strictly speaking, the break-even cost is defined only at the point where the actual system cost equals the break-even cost. This condition is required due to the assumed dependence of some recurrent costs on initial installed costs (e.g., property taxes).

interactive with the utility grid. PV technology achievable by 1986 is assumed to be deployed in a system that is purchased and placed in service at the end of 1986.*

The PV system is assumed to be incorporated as a part of new housing construction. PV system installation coincident with new housing design and construction offers several advantages to potential PV investors. Costs can be minimized when tract homes with PV systems are built, due to savings from quantity discounts, economies of scale for multiple installations, and replication of standardized system designs (rather than using custom designs). System design optimization for such an application can incorporate factors pertaining to the locale, the housing structure (e.g., the option for integrally mounted modules and the roof orientation), utility grid price structures, and expected homeowner characteristics (e.g., typical income level and appliance loads).

The baseline residential PV array is rated at 5.34 kW_p dc, at standard operating conditions (SOC)--1 kW/m^2--and nominal operating cell temperature (NOCT). It is integrally mounted on a south-facing rooftop tilted at the local latitude angle. The array is composed of 20 modules, two series-connected strings of 10 modules each. Module efficiency is 13.5% at SOC; array area is 39.6 m^2. Initial module electrical characteristics are designed for a short-circuit current of 22.5 amperes, open-circuit voltage of 14.4 volts, and fill factor of 0.7. A distribution of initial module short-circuit current levels that results in approximately a 5% power loss due to electrical mismatch between modules is assumed. The integral roof-mounting design causes modules to operate at a relatively higher temperature than that of a standoff-mounted array. This results in a PV energy output reduction of 2.5%. Additional losses (e.g., due to dc wiring and to parasitic power losses) also reduce array output received by the power-conditioning unit (PCU) by 5%. The power-conditioning unit is assumed to be 92.3% efficient at rated conditions. PCU efficiency drops off (linearly to zero) once array output falls below 24% of rated input to the PCU.** At SOC the size of the PV system is, therefore, 4.34 kW_p ac. It is assumed that the residential PV system has no dedicated electrical storage; demand for electricity in excess of PV output is satisfied by the electric utility.

The PV system is scheduled to be constructed within a short time period***, before the end of 1986. Three roof-mounting schemes are evaluated

---

*As discussed above, the level of technology development assumed at the time this study was performed (1981) now corresponds to expectations for the 1990s.

**This nonlinear representation of PCU efficiency, along with other nonlinear considerations (such as local weather conditions), requires the LCP model to calculate power output by time of day (i.e., hourly) for the residential PV study.

***The model assumption requires only that construction take less than one year. Residential PV system construction is typically much faster, making this constraint unlikely to be violated.

in this report: integral, direct, and standoff. Examples of methods for mounting PV modules on residential rooftops are as shown in Figure 3. For the baseline case, the integral mount configuration is chosen. The homeowner is assumed to receive a roof credit from the builder on the portion of the roof not requiring construction; e.g., for expenditures not made for materials, labor, and overhead.

Hourly PV performance estimates are based on locale-specific, integrated hourly weather data. Sources used in this study include SOLMET (Reference 6) Typical Meteorological Year (TMY) (Reference 7), and WEST Associates (Reference 8). (See Appendix B for additional details.) A single year's weather data are replicated in a deterministic fashion for each year of simulated PV system operation. Lack of multiple years of weather data constitutes an important limitation on the results of this study.

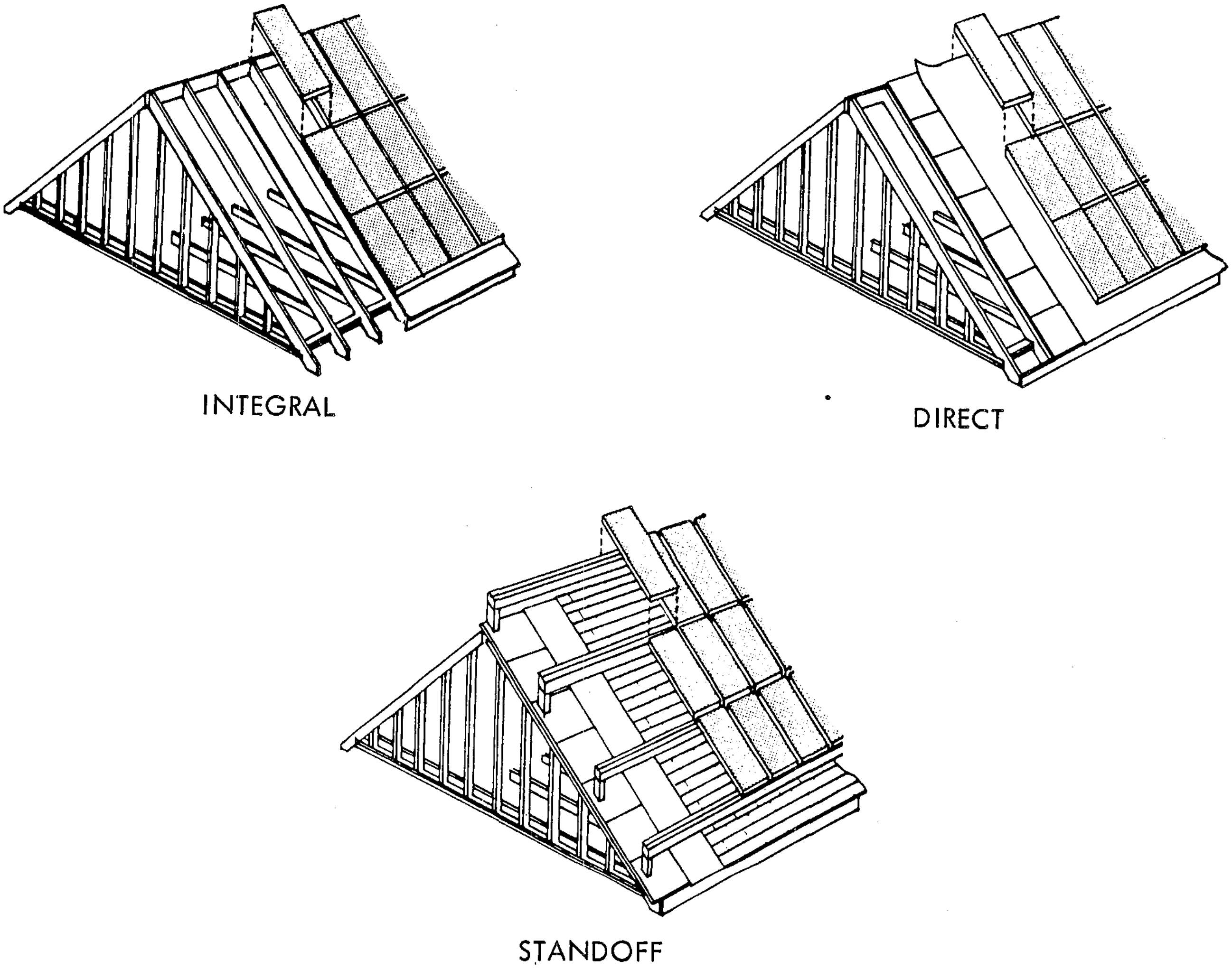

Figure 3. Examples of Photovoltaic Module Roof-Mounting Alternatives

Residential PV systems are assumed to operate for 30 years. Over that period the PV system experiences degradation of power output, and the system may require some maintenance. Module degradation caused by random events such as cell failures are simulated over the system lifetime. A 1%-per-year loss in module output due to cell failures is assumed as input. In addition, energy output losses due to the effect of electrical mismatch between modules are calculated. A bypass diode is included around each module. No module open-circuit failures are input into the baseline analysis. Dirt is assumed to collect on the front surface of the module. The rate (monthly input) at which power output is reduced due to dirt accumulation is site-specific* (References 9 and 10). The cleansing effect of precipitation is included, based on NOAA local climatic data.

PV system maintenance is assumed to be not extensive. By assumption, modules are allowed to operate over the entire system lifetime without replacement (Reference 11). Array cleaning by a contracted cleaning crew was evaluated as not cost-effective. Therefore, infrequent (zero, once, or twice per year, depending on location) module cleaning by the homeowner, typically done by hosing down, is assumed. A locale-specific increment to power output due to cleaning is incorporated. The power-conditioning unit requires a major overhaul every seven years.

2. Utility-Grid Interaction

The large-scale market for residential PV systems is expected to be for utility-grid interactive applications. Distributed nonutility-owned energy generation systems such as rooftop residential PV are allowed to interconnect with the utility grid under Sections 201 and 210 of PURPA**.

Provisions of PURPA require utilities to purchase electricity from qualifying distributed small power producers and cogenerators at their net avoided cost. Additionally, such qualifying facilities are exempted from virtually all state and federal utility regulations. Owners of qualifying facilities have the option to interconnect with the utility either in the parallel or the simultaneous mode of interconnection.

Under the parallel mode of utility interconnection, energy generated by the PV system is preferentially used to satisfy homeowner electricity demand. Any PV power output in excess of homeowner load, by time of day, is sold back to the utility at an agreed-upon price (e.g., sell-back rates for homeowners in the Southern California Edison Co. territory are obtained from SCE's Interim Proposed Policy for Cogeneration and Small Power Production, May 1981,

---

*Dumas, L., Module Durability Experience, Jet Propulsion Laboratory, Pasadena, California, private communication.

**Section 201 defines qualifying facilities, and Section 210 mandates that utilities must buy electricity from such qualifying facilities at the utility's avoided cost (Reference 5).

in compliance with California Public Utilities Commission regulation).* Utility buy-back rates based on avoided costs are used here as a proxy for utility marginal costs of fuel and capacity. Determination of the true value of PV to a utility requires simulation of utility capacity expansion and production costing. The homeowner is assumed to purchase any additional energy requirements from the utility grid, which serves as a back-up to PV output. Utility-specific customer rate schedules are used for the cost of grid-supplied energy.

Simultaneous PV-utility interconnection describes the case in which all PV energy output is sold directly to the utility. In this configuration, the PV system owner's decision to invest in the PV system is independent of his demand for electricity.

Table 1 presents the utility-related and customer-demand-related input assumptions used in this study. All inputs are supplied by the respective utilities. In some cases, only "representative" or averaged customer load profiles were available (e.g., Southern California Edison Co.). Prices for electricity purchase and sell-back are taken from the most recent information available before September 1981, and deflated to January 1980 dollars. Utility rate structures are detailed in Appendix B. Figure 4 displays data for residential customer load (Reference 12) and for PV output based on local weather conditions (Reference 8) from two single days (March 1 and July 1, 1979) for Barstow, California. When climatological data on this locale, PV system design characteristics, and homeowner information are aggregated on a yearly basis, extended over the system's operating lifetime, and incorporated into the financial analysis model, the optimal mode (simultaneous or parallel) of PV-utility interconnection is readily identified based on the calculated break-even costs.

3. Economic Assumptions

Residential PV system break-even costs are significantly affected by the economic assumptions used in the analysis. This subsection presents a discussion of the economic assumptions and options associated with the homeowner, tax-law interpretation, interconnected utility characteristics, locale, and operation of the PV system. Appendix C contains detailed assumptions regarding the methodology and base-case inputs.

a. Homeowner. Homeowner purchase of a PV system on a new home is the baseline case. A family of four with an annual gross income of $40,000 as of December 1986 is assumed. For tax purposes, family income is derived solely from wages and a joint return is filed. Since the PV system is purchased with the house, the loan is assumed to be at the same rate as the loan on the home (i.e., fixed mortgage interest rate = 14.5%, down payment = 20%, loan lifetime = 30 years, and deductible loan costs = 1.5%). The

*Although utility buy-back rates are to be set based on avoided costs, rates for a specific qualifying facility may result from either a standardized offering or a separate, contractually agreed-upon price.

Table 1. Utility- and Customer-Demand-Related Inputs

Locale	Utility Name	Annual Homeowner Load, kWh	Electricity Purchase Rate, 1980 ¢/kWh (and monthly kWh)	Sell-Back Rate, 1980 ¢/kWh
Alhambra, California	Southern California Edison Co.	8434	7.1 (>240 kWh) 4.9 (<240 kWh)	6.1–6.8
Barstow, California	Southern California Edison Co.	8434	7.1 (>240 kWh) 4.9 (<240 kWh)	6.1–6.8
Boston, Massachusetts	Boston Edison Co.	5599	8.0–10.9 (>384 kWh) 8.5 (<384 kWh)	2.5–5.4 (9 mo) 3.7–5.3 (June–Aug)
Denver, Colorado	Public Service Co. of Colorado	5830	7.1 (30–100 kWh) 5.2 (>100 kWh)	2.8
Honolulu, Hawaii	Hawaiian Electric Co., Inc.	9680	9.5	7.5
Lincoln, Nebraska	Lincoln Electric Utility Co.	12699	3.5–5.4 (summer, >400 kWh) 3.8 (<400 kWh)	1.2–2.2 (winter) 1.4–3.1 (summer)
Miami, Florida	Florida Power and Light Co.	12736	6.3 (>750 kWh) 5.8 (<750 kWh)	4.9–5.5
Midland-Odessa, Texas	Texas Electric Service Co.	8985	4.8–5.2	2.1 (summer) 1.6 (winter)
Phoenix, Arizona	Arizona Public Service Co.	10498	4.1–4.4	1.6–3.5 (summer) 1.4–2.8 (8 mo)

assumed interest rate is consistent with a 9% general inflation rate (based on estimates made at the time of this analysis in 1981, using projections from the Gross National Product Implicit Price Deflator). In nominal, after-tax terms, the homeowner's discount rate is 10.5%. The associated pretax discount rate varies from 14% to 19% as a function of homeowner income level and federal and state tax assumptions.

The homeowner has the option of interconnecting to the utility so that he sells either all of his system's PV energy output or any excess above personal consumption. Identification of the preferred mode of interconnection

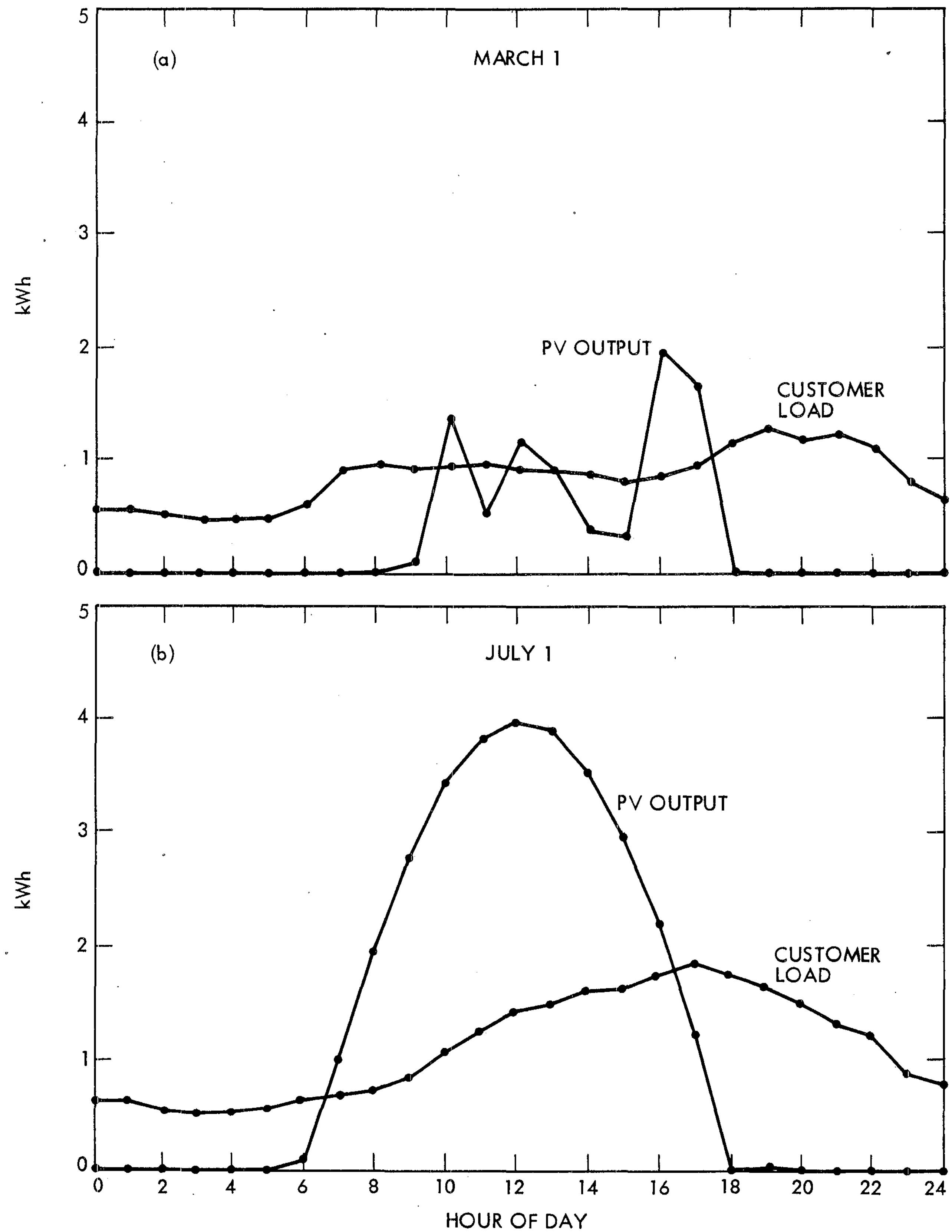

Figure 4. Sample Time-of-Day PV Output and Customer Load Profiles for Barstow, California (1979)

is based on proposed utility rates for purchase and sale, and the tax consequences of ownership (discussed below). A zero real electricity price escalation after the date of PV system purchase (for the purpose of determining a break-even cost) has been assumed. This allows the PV system to be competitive in cost (in constant dollars) with the energy supplied by the utility at the time of initial system operation. (See Reference 13.)

b. Tax Law. The assessment presented in this report is based on an extensive investigation of the tax consequences of owning and operating a residential PV system (Reference 14). Of primary importance is the determination whether the purchase and operation of a PV system by a homeowner constitutes a "trade or business" or the "production of income" if part or all of the solar-generated electricity is sold to a utility. The Internal Revenue Code of 1954 allows the business taxpayer to deduct all ordinary and necessary business expenses when he is engaging in a trade or business. Three of the most important criteria developed by the courts in applying the trade or business deduction are (1) the activity must be entered into with the expectation of making a profit, (2) there must be some regularity and continuity in its operation, and (3) the taxpayer must be actively involved in pursuing it*.

In the baseline cases, several alternative tax treatments of PV system costs and revenues are postulated. A "business" interpretation** for all or part*** of the residential PV activity implies that the PV system will both generate income that is subject to taxation, and yield tax benefits that reduce the homeowner's tax liability. The homeowner is assumed to receive income from the utility for the sale of electricity. Tax liability of the PV system owner is, however, reduced due to tax credits and tax deductions. For the baseline cases, only the regular federal 10% investment tax credit on qualifying property****, and similar state-specific tax credits (e.g., Colorado

---

*Lamm, D.S., Reduction of Nonbusiness Gross Income by PV System Operating Expenses, JPL Interoffice Memorandum 311.8-415, to R.B. Davis, Jet Propulsion Laboratory, Pasadena, California, October 22, 1980

**The homeowner is assumed to satisfy the "trade or business" criteria identified above (i.e., the profit motive and operational requirements), although he may be additionally motivated to purchase a residential PV system for non-business-related reasons (e.g., reduced dependence on a utility grid, personal status, environmental considerations).

***This refers to simultaneous or parallel interconnection to the utility and is described in more detail below in this section.

****Requirements for qualifying property include: a "for profit" activity, determinable useful life of equipment, tangible property, and property may not be a "structural component." The type of roof mount will probably affect the eligibility of the array for the investment tax credit. (See discussion below).

and Nebraska), are included. Neither the residential nor the business-related solar tax credits are incorporated into the baseline cases. The reasons are twofold: (1) the credits are currently scheduled to expire on December 31, 1985 (before the installation date assumed in this analysis) and renewal of the credits is highly speculative, and (2) for the purpose of setting cost targets for PV technology, it is desirable to base these targets on expected competitive market requirements for energy-generating systems. If the cost targets can be achieved, private incentives (without special government subsidy) are likely to be sufficient to create a profitable, private PV industry and market. Since the intent of the solar tax credits is to encourage a new industry temporarily rather than to correct for market imperfections permanently, they have been excluded from the baseline case. The exclusion is, however, controversial.

Two classes of tax deductions arise from residential PV activity. The first can be labeled "otherwise allowable personal deductions." These deductions include property taxes assessed on the PV system, and interest paid on indebtedness incurred to purchase the PV system. The Internal Revenue Code specifically permits the taxpayer to deduct these expenses even if they arise from a completely personal activity.

The second class of deductions can be labeled "business deductions." Included in this class are operation and maintenance expenses, insurance expenditures, and Accelerated Cost Recovery System (ACRS) deductions.* Unlike otherwise allowable personal deductions, the individual taxpayer may not always deduct business expenses fully. Specific rules are provided in the code respecting their deduction. When business expenses arise from a profit-oriented activity, they generally may be fully deducted even if the activity actually produces no income. Thus, if the residential PV activity is considered to be engaged in for profit, then the homeowner may be able to deduct business expenses in excess of the income produced by the PV system and thereby reduce his personal income, which otherwise would be subject to taxation. It is a base-case assumption that the homeowner purchases and operates the residential PV system with the objective of making a profit, and for this reason, he is permitted to deduct any losses arising from the residential PV activity. Rules for determining profitability are discussed below and in Appendix C.

<u>Four Base-Case Tax Treatments</u>. "Business" tax treatments for both simultaneous and parallel PV-utility interconnection are evaluated. In both cases, all energy generated that is sold to the utility for revenues is treated as income. For the Parallel, Business case, energy used to satisfy the homeowner's load is determined to be for personal use. The amount that is sold back to the utility establishes the "sell-back fraction," and this fraction is the basis for apportioning business use versus personal use of the PV system.

---

*Before the establishment of the Accelerated Cost Recovery System, the taxpayer was permitted to recover an annual amount that approximated the wear, tear, and loss of value due to obsolescence of equipment by claiming a depreciation deduction. The depreciation system has been substantially modified by the ACRS rules that originated in the Economic Recovery Tax Act of 1981 (ERTA) (Reference 15).

Two additional sensitivities affecting break-even values are evaluated. Under the first sensitivity, denoted the Hobby case, it is assumed that the PV activity is not engaged in for profit.* In the Hobby case, the homeowner may not deduct losses arising from the residential PV activity. The second sensitivity is termed Bill Offset. As distinct from the Business or Hobby cases, it is assumed that the homeowner in the Bill-Offset case does not receive cash income for excess PV generated electricity that is sold to a utility. Instead, the homeowner's electricity bill is simply offset by the value of the electricity sold to a utility. It is assumed, therefore, that there is no taxable income and that the homeowner does not claim any business deductions arising from the residential PV activity.

Deduction of Losses. Several requirements must be satisfied for the residential PV system to qualify for the deduction of operating losses from gross income.** These are:

(1) Activity must not be primarily for personal purposes.

(2) Activity must be engaged in for profit.

(3) Activity must be classified as a "trade or business" or "income-producing property."

For the Hobby and Bill-Offset alternatives, deduction of operating losses is disallowed. Simultaneous, Business and Parallel, Business interpretations are discussed below.

---

*The code specifies the following order in which deductions associated with a hobby or not-for-profit activity may be taken. First, otherwise allowable personal deductions must be offset against activity-related income. If the activity-related income exceeds the amount of otherwise allowable personal deductions, then business expenses, except depreciation and other deductions that reduce the basis of an asset, may be deducted against activity-related income. Finally, if activity-related income remains after the first two classes of deductions have been taken, business deductions that reduce the basis of an asset may be taken to the extent of the remaining activity-related income.

**The rules restricting residential dwelling unit deductions carry a warning in this analysis. Rules respecting the business use of a residential dwelling unit limit expenses to gross income from the business activity. Deductions could be limited to interest and property taxes. These rules are not applicable to the base-case sites, since some PV systems are not part of the dwelling unit and use of the dwelling unit is not as contemplated in the regulations. If the rules were to hold, residential PV systems operated in the parallel mode would be a "least-favored tax activity."

The first requirement is readily satisfied in the case of simultaneous PV-utility interconnection, because all energy generation is sold to the utility for compensation, with no personal use of the PV system output. In the parallel mode of interconnection there is partial sell-back and partial personal use. For the Parallel, Business mode it is concluded that use of the PV system is not primarily for personal purposes on the bases that both personal and business functions are important, sell-back fractions have been calculated for virtually all sites (60%), and the personal function is nonessential.

One popular rule of thumb for determining if an activity is engaged in for profit is whether the activity generates profits in two of five consecutive years. Under some "reasonable economic assumptions," some of the base-case sites come close to this criterion. (See Appendix C, Part IV.E.2 for an example of the profitability analysis.) If the activity does not attain this objective, however, no negative inference is permissible. A profit motive is suggested by such criteria as: operation in a businesslike manner, consultation of experts (PV system and utility), no extreme pleasure benefits, and profitability over a longer period of time (less than or equal to the system lifetime). A lack of a profit motive may be indicated by little time and effort expended by the system owner, a long history of losses, and losses sheltered by taxpayer's income.

Determination of whether a residential PV system should be classified as a trade or business depends on: a profit motive, an investment activity (purely investment activities are excluded), a business activity (one presents oneself to others as a seller of goods or services), consistency and regularity, and substantial time and effort expended. Similarly, income-producing property requires a profit motive, includes purely investment activities, and must fall within the plain meaning of the regulation. Residential PV systems are concluded to be a trade or business, and income-producing property in the base-case (business) assumptions.

Structural Components. If the residential system, or some part thereof, is considered to be a structural component of the building in which it is installed, that portion of the system will not qualify for the federal investment tax credit (ITC). Several criteria and potentially conflicting tests have been used to determine whether a given item is a structural component that is ineligible for the ITC or is "tangible personal property" that is eligible for the ITC. Generally, the regulations and cases provide that property will be considered as a structural component if it is a part of the building that is not easily removable, if it is a permanent covering to a floor, ceiling or wall, or is related to the operation and maintenance of a building. Under virtually all of these standards, the power-conditioning unit that converts PV-generated dc electricity to ac is likely to be considered tangible personal property. This PV system component therefore is assumed to be eligible for the ITC in the base-case analysis.

Several designs could be used to mount the PV modules onto the residence. Some configurations, such as the standoff mount, have little structural relationship to the residence and should be removable with little damage. It is likely that these components will be eligible for the ITC. It is less certain, however, that the direct-mount modules will qualify for the credit. If direct-mount modules are cemented or otherwise permanently affixed to the roof, or if they cannot be removed without noticeable damage to the structure, they may be considered a "part of the building or permanent covering therefor," which is ineligible for the credit. Furthermore, even if the modules are easily removable, they may be classified as structural components if the protective function of the direct-mount shingles or panels prevent their qualification for the credit.

The base case assumes that the residence will be equipped with integral-mount PV modules that essentially compose the residential roof. It is conceivable that a court might adopt a permanency test and hold that integral-mount modules are not structural components of the building, because they are easily removable without damage to the structure. However, the adoption of this sole criterion for classification would ignore the obvious structural role played by the integral-mount modules. In the absence of congressional or regulatory intervention to the contrary, integral-mount modules are most likely to be classified as structural components. Since the base-case analysis uses the integral-mount configuration, it is assumed that the base-case modules are not eligible for the ITC.

The classification of the PV modules as either a structural component or tangible personal property will have at least one additional tax consequence. This consequence concerns the amount of annual deductions the homeowner will be permitted to take for wear, tear, and ordinary obsolescence of the PV property. Before the Economic Recovery Tax Act of 1981 (ERTA), this deduction was classified as depreciation. ERTA generally replaces the depreciation system with the Accelerated Cost Recovery System. Under the ACRS rules, the cost of tangible personal property is recoverable over a five-year period. Thus, if the PV modules are regarded as structural components, not only do they become ineligible for the ITC, but also their cost-recovery period may be lengthened from 5 years to 15 years. When the ITC is not taken, however, the basis for ACRS deductions is higher, thereby offsetting somewhat the loss of the ITC.

c. Utility Interface. The primary means of establishing a dollar value for PV output is through homeowner rates for electricity purchase and sell-back to the utility. Current residential rates for each utility in the break-even cost analysis, including any block rate structures or lifeline rates, are projected to the time of PV system operation. Sell-back rates are based upon either utility offerings pursuant to PURPA or are projected based on utility-specific avoided fuel costs. (See Appendix B for utility rate-structure details.) It is assumed that the utility can meter energy flows in two directions and can account accurately for time-of-day PV output and customer loads. Any interconnection costs are included in the calculated break-even cost.

d. Locale-Specific Financial Assumptions. Locale-specific tax assumptions are incorporated into the residential PV system analyses (see Appendix C). As with federal tax law, state energy tax credits are excluded from the baseline cases. Locale-specific property taxes on the PV system are included as annual operating costs. In some states (Arizona, Florida, and Massachusetts), exemptions for some limited period of time (3, 10, and 20 years, respectively) are already in place. These exemptions are incorporated in the base cases.

Personal income taxes for each of the base-case locales are evaluated using the simplifying assumptions about the sources of homeowner income and homeowner deductions detailed in Appendix C, Part VIII. Two of the baseline locations, Florida and Texas, have no personal income taxes. In Colorado and Arizona, federal taxes paid are a deduction at the state level (in addition to state taxes being a deduction at the federal level). The procedure for determining the mutual deductibility of taxes is derived in Appendix C, Part IX.

e. PV System Operating Costs. Recurrent costs for residential PV system operations and maintenance are treated as either business or personal expenses, depending on the relevant tax alternative described above. PV system insurance is estimated at 0.5% of initial installed system cost per year, and commences in the first year of full operation (1987). The cost of insuring the PV portion of the home during the construction phase is assumed to be an indirect cost borne by the builder and is included in the PV system cost. Cleaning and inspection of the array is assumed to be performed by the homeowner at infrequent intervals. Cleaning intervals are site-specific, with at most two manual cleanings per year by hosing down the arrays (see Appendix B, Part V, for additional details). The assumed cost to the homeowner of this simple cleaning procedure is $5. Power-conditioning units are assumed to require a major overhaul every seven years at a cost of $250 per overhaul.

C. LIMITATIONS

The procedure used to calculate PV system break-even costs (described in II.A above) has several input data and methodology-related limitations that affect the usefulness of model results. Although a significant effort has been made to validate model assumptions and input values, reliable input data on many economic, technical, and environmental parameters are limited. Technical inputs are based on limited PV-system operating experience and on projections of future technology development. Predictions of the cost and escalation rates (before installation) of the alternatives to PV electrical generation can greatly influence PV system value. In addition, uncertainties arise with regard to the quality and completeness of insolation and temperature data bases, and with regard to estimates of customer time-of-day electricity demand, utility purchase and sale rate structures, and PV-utility interconnection costs and requirements. Furthermore, as noted above, lack of multiple years of weather data constitutes an important limitation on the result of this study.

Limitations result from the approaches and assumptions used in the evaluation methodology (LCP-APSEAM). Though there is confidence that model limitations do not invalidate the results presented in this report, several potential concerns are present:

(1) Are the results of this case study sufficiently generalizable to the national level?

(2) Is the use of utility rate structures and proposed utility avoided-cost rates appropriate for use by homeowners in evaluating the purchase of a PV system?

(3) Is it appropriate to evaluate PV against grid electricity only, rather than including other technologies available to the homeowner (such as wind systems)?

(4) Are additional financial figures of merit required to illuminate varying levels of risk and liquidity among energy investment choices?

Although these and other limitations exist, model results are believed to be sufficiently robust for the purposes of directing PV technology development.

SECTION III

BASE-CASE RESULTS AND SENSITIVITIES

A. BASE-CASE RESULTS

Using the approach and assumptions described in Section II, base-case break-even costs for residential PV systems were developed for nine locales. Results are presented in Table 2. The assumed PV system is a 4.34 kW_p ac integral mount array operating in parallel with the utility grid. Figure 5 shows the first year's energy output for all nine sites. A significant variation in annual energy output between desert locales (Phoenix and Barstow) and northern locales (Boston and Lincoln) is evident. PV system design assumptions are presented in Appendix B, Table B-5, and weather data sources are shown in Appendix B, Table B-7.

The homeowner is allowed to choose between parallel (PV-generated electricity in excess of homeowner load is sent to utility grid) and simultaneous (all PV-generated electricity sent to utility grid) modes of PV-utility interconnection. A variety of tax treatments resulting from investment in a PV system are evaluated. These are defined as:

Parallel, Business:	Parallel interconnection; PV-system dollar losses applied against other sources of income; investment tax credit applies to business fraction
Simultaneous, Business:	Simultaneous interconnection; PV system dollar losses applied against other sources of income; investment tax credit applies
Hobby:	Parallel interconnection; dollar losses limited to PV system sell-back revenues; no investment tax credit applies
Bill Offset:	Parallel interconnection; no explicit revenues; PV-generated electricity offsets purchases from utility; only interest and property taxes deductible; no investment tax credit applies.

No energy-tax credits are included in the base-case results.

Residential PV system break-even costs are shown in Table 2 for the base-case assumptions (e.g., 4.34 kW_p ac system, parallel interconnection, business tax treatment, integral-mount array, $40,000 per year homeowner income (1980 $), and no solar tax credits. These break-even costs range from $1.00/$W_p$ (1980 $) in the least attractive locales to more than $3.00/$W_p$ ac (1980 $) in the highest-valued locale. The ranking of relative attractiveness (i.e., highest break-even cost) of residential PV systems across virtually all tax treatment alternatives is: Honolulu, Hawaii; Barstow, California; Alhambra, California; Miami, Florida; Boston, Massachusetts; Denver, Colorado; Midland-Odessa, Texas; Phoenix, Arizona, and Lincoln, Nebraska.

Table 2. Base-Case Residential PV System Break-even Cost Results for Different Locales and Tax Treatments (Integral-Mount Configuration), 1980 $\$/W_p$ ac

Locale	Tax Treatment			
	Parallel, Business	Simultaneous, Business	Hobby	Bill Offset
Alhambra	2.63	2.19	2.41	2.82
Barstow	2.91	2.42	2.67	2.92
Boston	1.81	1.27	1.60	1.77
Denver	1.49	1.11	1.31	1.42
Honolulu	3.31	2.56	3.06	3.33
Lincoln	1.09	0.68	1.00	1.02
Miami	1.90	1.43	1.84	1.88
Midland/Odessa	1.47	0.77	1.31	1.33
Phoenix	1.42	1.01	1.33	1.40

Variations in the tax assumptions for the four tax treatments imply a significant change in allowable residential PV system costs. In particular, parallel interconnection with the local utility and business tax treatment dominates the Simultaneous, Business alternative for each locale. The primary factor in this result is the differential between proposed, or inferred, rates for utility buyback of electricity from the distributed PV system and projected residential rate structures. Treating PV system revenues under a Hobby interpretation causes approximately 10% reduction in allowable system cost relative to Parallel, Business since losses are limited to annual gross income generated by the PV system and the investment tax credit is excluded. Offsetting kilowatt hours by sending electricity back to the utility grid (the meter is ratcheted back by the relative price per kilowatt hour) has a break-even cost roughly equivalent to that of the Parallel, Business case. For all sites and tax treatments, the simultaneous mode of interconnection is dominated by the parallel mode.

The primary factors influencing allowable PV system cost differentials between locales are the relative insolation levels, utility rate structures, and state tax considerations. To illustrate the effects of these attributes, Figure 5 shows the baseline PV system design generating a wide range of annual energy output levels, with Phoenix having the highest level. However, the break-even cost associated with that locale is one of the lowest calculated

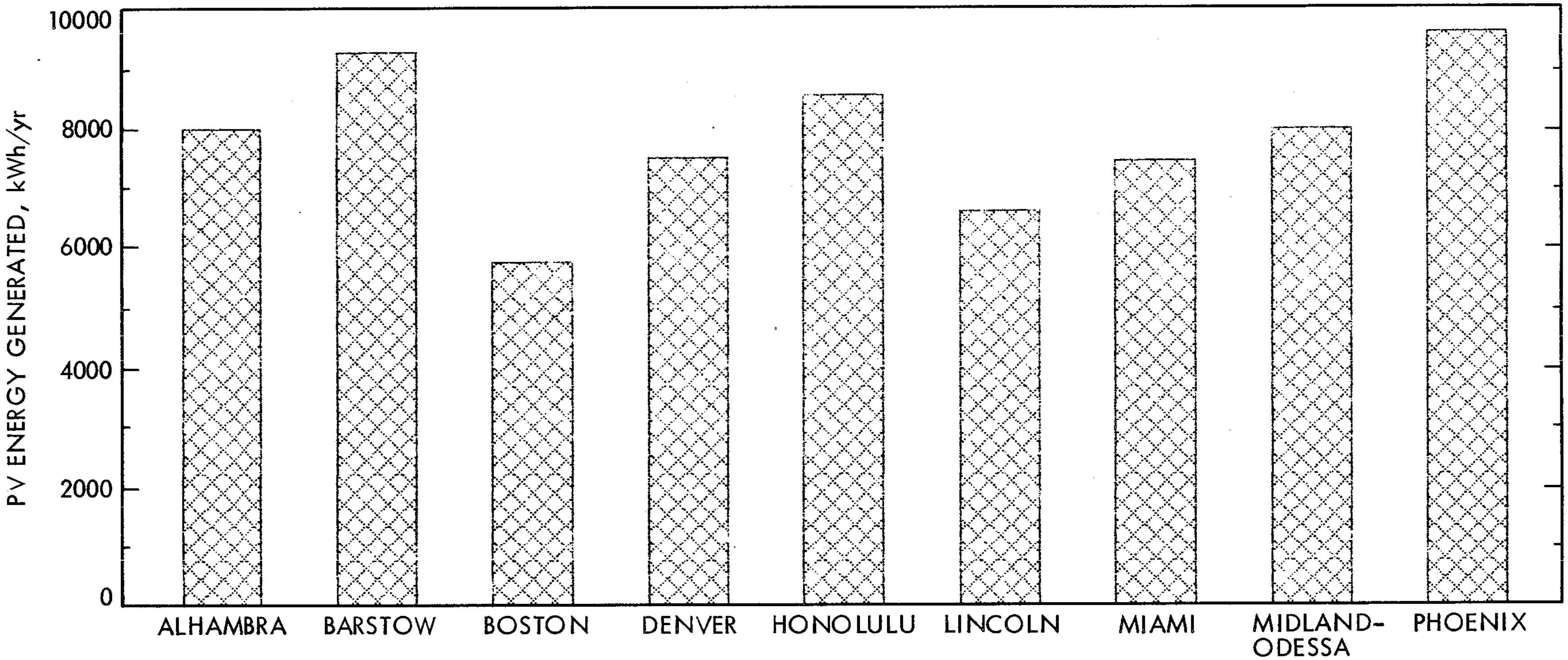

Figure 5. First Year's Energy Output for 4.34 kW_p ac Residential Photovoltaic Systems in Base-Case Locales, kWh/yr

for all of the base-case locales. A sensitivity analysis is presented in Subsection III.B to explore further the potential significance of utility rate structures and state tax law on allowable PV system cost.

Sensitivities are provided in the remainder of this section for a number of financial assumptions, PV system considerations, and government incentives. Interpretations are presented for each alternative.

B. FINANCIAL SENSITIVITIES

To extend the applicability of the base-case results, a number of assumptions related to the financial environment have been varied. These sensitivities are based on differences in homeowner, location, and recurrent cost attributes.* Homeowner financial sensitivities highlight the effects of changes in annual income level, discount rate and mortgage interest rate assumptions on break-even cost. In addition, the effects of utility rates and state tax laws on break-even cost is presented by substituting California data for Arizona data. An illustrative example of the effects of recurrent costs on break-even costs is presented for an insurance-expenditure sensitivity. The baseline PV system design described above remains constant throughout the financial sensitivity analyses.

The assumed PV homeowner earns $40,000 annually in 1986. Break-even cost sensitivities to income level are displayed in Table 3 for a range of sites (Honolulu, Phoenix, and Boston). These results are also illustrated in Figure 6. Detailed tax assumptions for the various income levels are listed in Appendix C. It is seen that increasing homeowner income level is associated with increasing break-even costs, because of the greater marginal tax rate of the investor and the greater value to him of the tax deductions associated with the PV investment. Simultaneous, Business treatment is the least preferred for all homeowner income levels. For all three sites, the cost per kWh of purchased electricity is greater than the revenues per kWh for electricity sold back to the grid. Thus, a homeowner connected to the grid in the simultaneous mode realizes less after-tax revenues from the sale of PV-produced electricity than it costs him to "replace" that PV-produced electricity with electricity from the grid. If the customer rates for the purchase of electricity from the utility grid were closely matched to utility marginal costs of supply, including generation (by time of day), this difference would probably diminish significantly.

Homeowner after-tax discount rate is assumed to be 10.5% (pretax range = 14.9% - 16.3% and inflation = 9%) in the base case. Figure 7 displays the sensitivity of break-even cost to a range of after-tax rates, assuming annual homeowner income varies between $20,000 and $50,000 and a Parallel, Business utility interconnection and tax environment. A relative insensitivity is shown for discount-rate variation in locations having both low sell-back revenues and low break-even costs. For areas with high break-even costs and high revenues from the sell-back of electricity, break-even cost variations can be significant.

---

*The effects of state and federal tax incentives are presented in Subsection III.D, below.

Table 3. Break-Even Cost Results for Different Homeowner Income Levels, 1980 $\$/W_p$

Locale	Homeowner Income 1980 $	Tax Treatment: Parallel Business	Simultaneous, Business	Hobby	Bill Offset
Honolulu	20,000	2.91	2.36	2.78	2.97
	30,000	3.12	2.44	2.93	3.17
	40,000	3.31	2.56	3.06	3.33
	50,000	3.46	2.66	3.14	3.44
Phoenix	20,000	1.28	0.96	1.23	1.28
	30,000	1.36	0.98	1.29	1.34
	40,000	1.42	1.01	1.33	1.40
	50,000	1.47	1.04	1.37	1.44
Boston	20,000	1.59	1.18	1.49	1.61
	30,000	1.71	1.21	1.54	1.70
	40,000	1.81	1.27	1.60	1.77
	50,000	1.89	1.31	1.63	1.81

The homeowner is assumed to finance the PV and home purchase with a mortgage type-loan at 14.5% for a 30-year term. Figure 8 shows the sensitivity of the break-even cost for the Parallel, Business tax treatment in Phoenix and Honolulu for various mortgage interest rates on the loan (range: 10% to 20%) and for various loan lifetimes (15 to 30 years). For Honolulu, all three curves cross at an interest rate of about 19%. This is the homeowner's pre-tax discount rate, and he is indifferent, at this interest rate, to the timing for the flow of funds.

Base-case break-even costs for PV systems in Phoenix appear low, given the expected insolation levels for that site. The primary reasons for this result are low utility sell-back rates and high property-tax rates in Phoenix. Table 4 displays the results of modifying electric utility rates and state tax rates for the baseline PV system (integral mount) and homeowner ($40,000 per year income). The first row of the table shows baseline break-even costs for the various tax treatments assuming a Phoenix location with Arizona Public Service Co. buy-sell rate structures and the effective property tax rate in Phoenix (2.89%).* In the second row of the table, everything is kept constant except that Southern California Edison Co. rate structures are substituted for the Arizona Public Service rates (see Appendix B). The effect is a significant increase in break-even cost, on the order of $\$1.10/W_p$ to $\$1.25/W_p$ across all tax treatments. Finally, Barstow property tax assumptions then replace the Phoenix assumptions, resulting in the increases in break-even costs shown in the third row of approximately $0.65 to $\$0.80/W_p$. The resulting artifically combined $\$3.36/W_p$ break-even cost for Parallel, Business and annual homeowner income of $40,000 is higher than the base-case results for any locale in this study.

---

*State property-tax incentives are discussed in Subsection III.D.

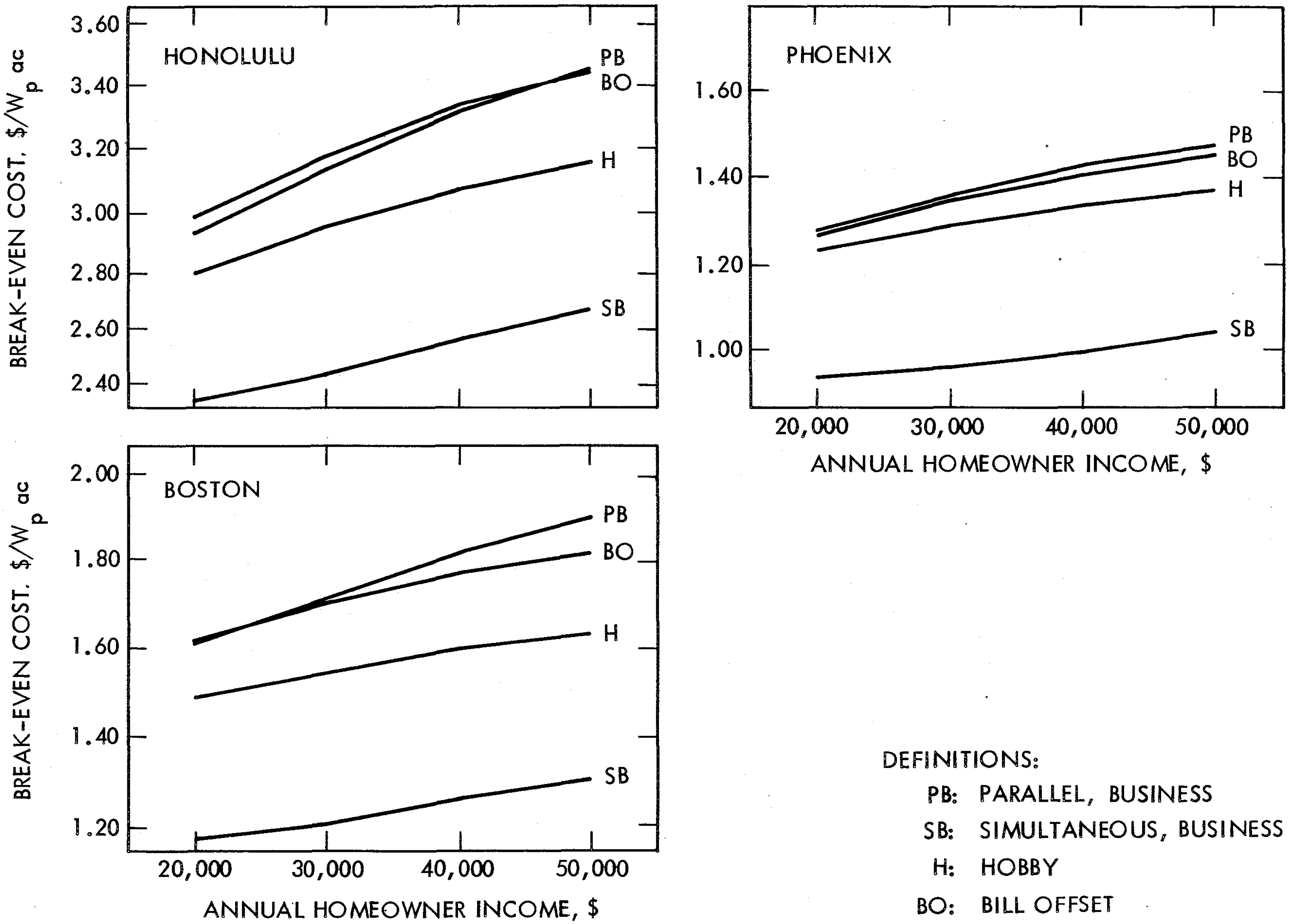

Figure 6. Residential Photovoltaic System (Integral Mount) Break-Even Costs for Various Homeowner Annual Income Levels (All Figures Are 1980 $)

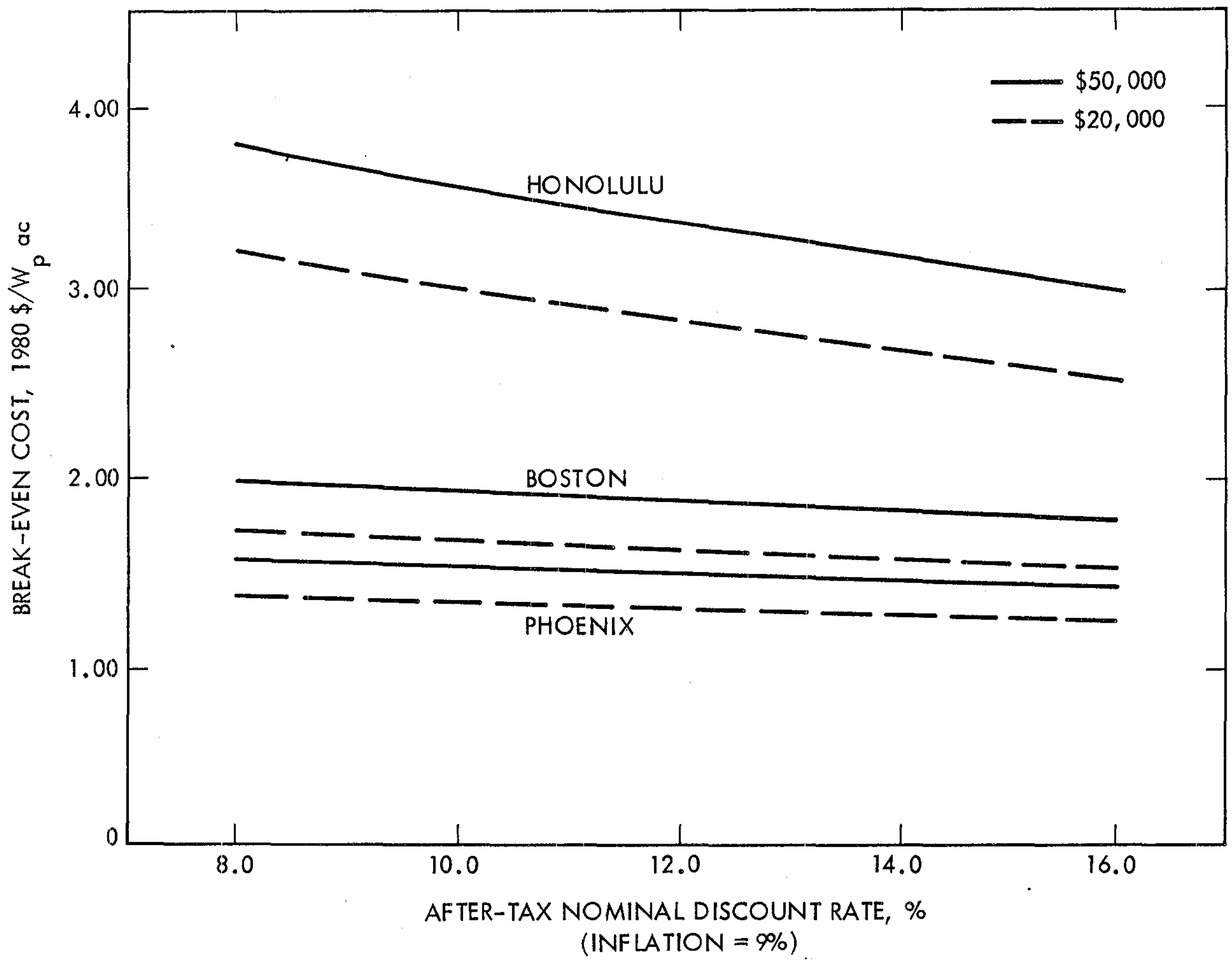

Figure 7. Residential PV System Break-Even Costs for a Range of Homeowner Discount Rates, 1980 $\$/W_p$ ac

Recurrent expenditures can have a significant negative impact on PV system break-even costs. As an example of the effect of operating expenses on allowable system costs, the cost of insurance is highlighted in Table 5. The baseline cost is 0.5% of installed capital cost per year. For the sites at Honolulu and Phoenix, expenditures for insurance cause a 10% reduction in system break-even cost for each 0.5% of installed capital cost per year increase in insurance rate.

C. PV SYSTEM CONSIDERATIONS

Several sensitivities relating to the PV system are evaluated in terms of system break-even costs. In particular, the effects of PV system size variations and different PV array degradation rates are evaluated. In addition, break-even cost sensitivity to the roof-mounting mode (integral, direct or standoff) is presented. For all cases considered, the baseline homeowner financial description is used.

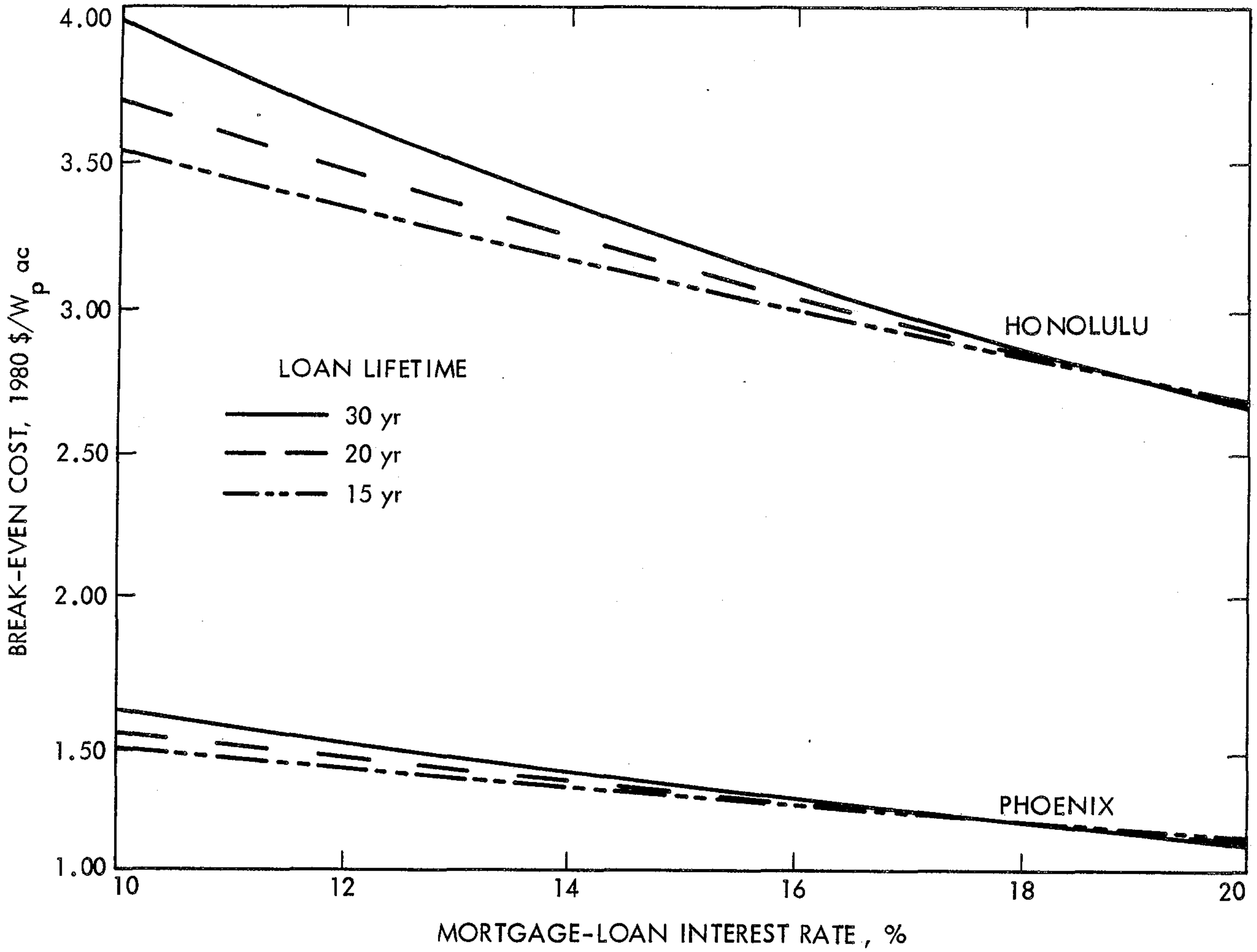

Figure 8. Residential PV System Break-Even Cost Sensitivity to Mortgage-Loan Interest Rates

An evaluation of PV system break-even cost as a function of system size is considered. Results for the Phoenix location, assuming an integral roof-mount configuration, are presented in Table 6. Trends are similar for other locations. Preference for smaller system size results primarily from rates for customer purchase of electricity being higher than utility buy-back rates. In the Simultaneous, Business case, break-even cost is independent of homeowner load and customer rates and, therefore, does not vary with system size.

Assuming the baseline 4.34 kW_p residential PV system and all assumptions identified above, a sensitivity analysis of annual module degradation rates is presented. The effects of module degradation over the PV system's operating lifetime (e.g., due to cell failure or discoloration of the encapsulant) and the resulting electrical mismatch within the array are simulated using the Monte Carlo simulation capability of the LCP model (Reference 2). Break-even cost variations shown in Table 7 are based on the calculated PV system degradation levels as shown in Figure 9. These array degradation factors are simulated for each month of the PV system's operating lifetime and are averaged over multiple simulation runs to yield the nonsmooth curves in

Table 4. Residential PV System Break-Even Cost Sensitivity to Utility Rate Structure and State Tax Law, 1980 $\$/W_p$ ac

Locale, Utility & State	Tax Treatment: Parallel, Business	Simultaneous, Business	Hobby	Bill Offset
Phoenix, Arizona Public Service, Arizona	1.42	1.01	1.33	1.40
Phoenix, Southern California Edison, Arizona	2.57	2.17	2.44	2.63
Phoenix, Southern California Edison, California	3.36	2.85	3.09	3.30

Table 5. Residential PV System Break-Even Cost Sensitivity to Insurance Rates, 1980 $\$/W_p$ ac

Locale	Insurance Rate	Break-even Cost, $\$/W_p$ ac
Honolulu	0.00%	3.68
	0.25%	3.49
	0.50%	3.31
Phoenix	0.00%	1.54
	0.25%	1.48
	0.50%	1.42

are averaged over multiple simulation runs to yield the nonsmooth curves in Figure 9. It is assumed that no modules are replaced. Due to the availability of protective hardware, module degradation will probably average less than 1% per year by the time these system costs are achieved.

Table 6. Residential PV System Break-Even Cost Sensitivity to System Size, 1980 \$/W_p ac

		Tax Treatment			
Locale	System Size, kW_p ac	Parallel, Business, \$/W_p ac	Simultaneous, Business, \$/W_p ac	Hobby, \$/W_p ac	Bill Offset, \$/W_p ac
	2.17	1.60	1.01	1.56	1.57
Phoenix	4.34	1.42	1.01	1.33	1.40
	8.68	1.26	1.01	1.16	1.27

Table 7. Residential PV System Break-Even Cost Sensitivity to Annual Module Degradation Rate, 1980 \$/W_p ac

		Tax Treatment			
Locale	Annual Module Degradation Rate, %	Parallel, Business, \$/W_p ac	Simultaneous, Business, \$/W_p ac	Hobby, \$/W_p ac	Bill Offset, \$/W_p ac
	0	1.66	1.22	1.56	1.69
Phoenix	1	1.42	1.01	1.33	1.40
	3	1.16	0.82	1.09	1.11

Several designs are currently being considered for mounting modules on residential rooftops. Described in II.B.1 above are integral, direct and stand-off mounts. The integral mount is chosen as the base case. Since the modules are replacing conventional materials for roof construction, a roof credit can be inferred. Integrally mounted modules receive a significant credit; direct-mounted modules receive a lesser credit, and stand-off modules zero credit.

The impact on break-even costs at two base-case locales (Barstow and Phoenix) of different PV roof-mount configurations is shown in Table 8. The combined effects of roof credits, tax treatment and energy output variations due to module heating differentials are shown. An incremental 7.5% energy output penalty for direct-mount modules versus integral-mount modules is included due to increased module heating. The roof credit for the direct-mount

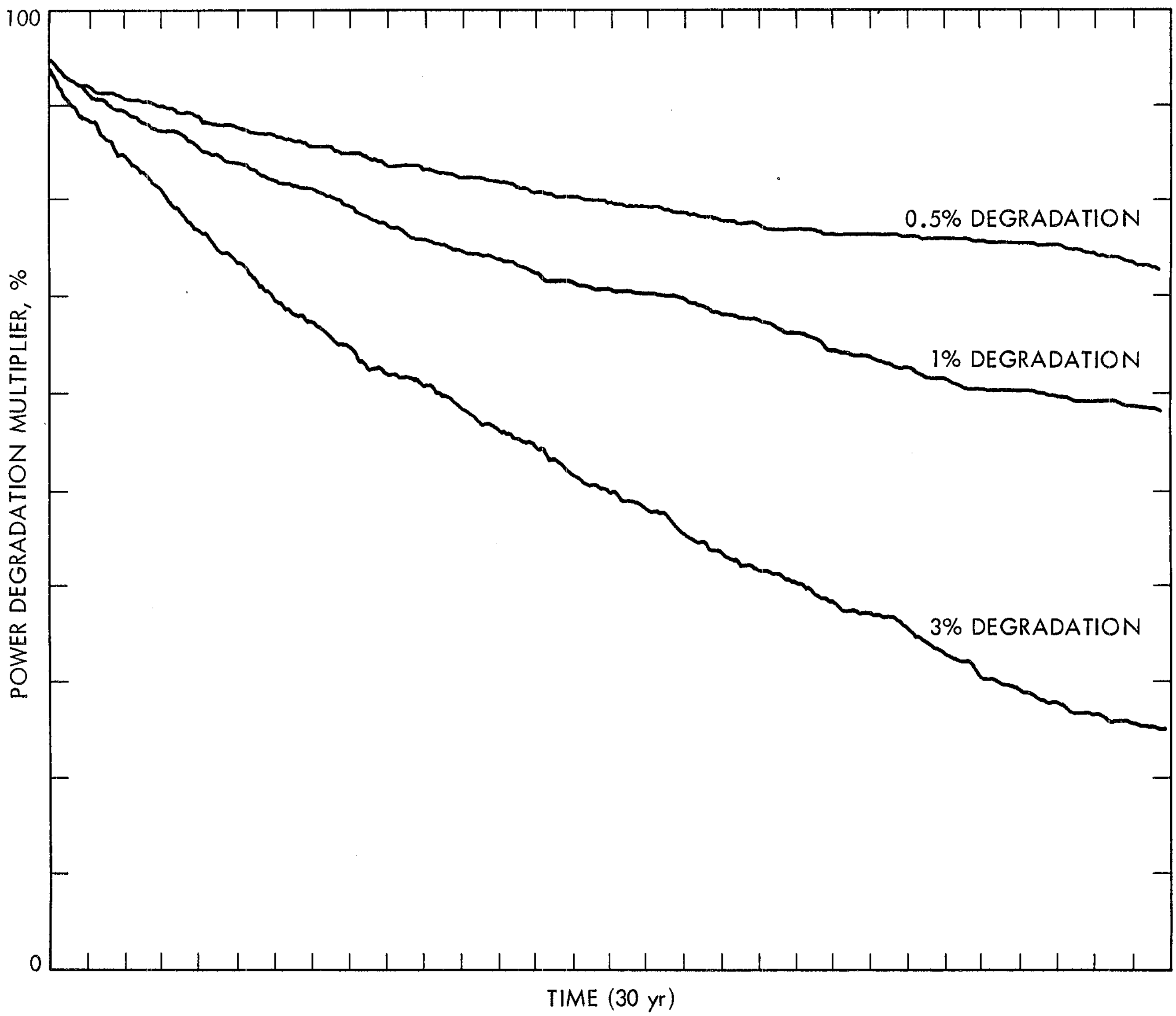

Figure 9. PV System Degradation Over Time for Various Annual Degradation Rates

technique is assumed to be $935 (in 1980 $) (Reference 16). A comparison of the two middle columns, Direct Mount not containing a structural component and Direct Mount containing a structural component, reveals the empirical impact of this tax code classification. At both locales, the most substantial difference in break-even values occurs in the Parallel, Business tax treatment. Two factors are responsible for this difference. First, in the direct, nonstructural case, an investment credit is allowable for module expenditures, whereas under the direct, structural interpretation, the ITC is not allowable. Second, since the ACRS deductions can be recovered in five

Table 8. Residential PV System Break-Even Cost Sensitivity to Roof-Mount Configuration, 1980 \$/W_p ac

Locale, Tax Treatment	Configuration			
	Integral Mount, \$/W_p ac	Direct Mount, Nonstructural, \$/W_p ac	Direct Mount, Structural, \$/W_p ac	Standoff Mount, \$/W_p ac
Barstow				
Parallel, Business	2.91	2.84	2.59	2.88
Simultaneous, Business	2.42	2.55	2.12	2.49
Bill Offset	2.92	2.62	2.62	2.70
Hobby	2.62	2.30	2.32	2.35
Phoenix				
Parallel Business	1.42	1.30	1.21	1.17
Simultaneous, Business	1.01	0.93	0.82	0.73
Bill Offset	1.40	1.20	1.20	1.13
Hobby	1.33	1.12	1.13	0.98

years under direct, nonstructural rather than 15 years under direct, structural, the former deductions for cost recovery will have a higher present value to the homeowner. Break-even values at both locales for the Bill Offset and Hobby tax treatments remain essentially the same for both direct-mount alternatives. The break-even value associated with the Bill Offset tax treatment for the direct mount does not change because no investment tax credit or business deductions are assumed to be allowable. For the Hobby tax treatment, a slight increase in break-even cost is calculated. This is caused by the hobby interpretation that restricts operating expenses to revenues. Losses during the first five years cannot be offset against other income, and are therefore lost. As shown in the tables, the energy output losses (7.5%) resulting from increased heating of direct-mount modules (as compared with integral-mount modules) cannot be offset by the tax assumptions for the direct, nonstructural case. Using the "structural" interpretation for direct-mount modules, break-even costs are much lower than for the integral mount.

In the standoff array roof-mounting alternative, PV system energy output is increased over the baseline integral-array design by 2.5% due to improved module heat rejection. The homeowner does, however, lose the roof credit. For tax purposes, the array is considered to be a nonstructural component. Table 8 shows that the standoff array configuration is, in general, not a preferred option.

Table 9 presents the base-case results for the Parallel, Business tax treatment, the $40,000 annual income homeowner, and the integral-mount roof configuration for each locale assuming a site-independent roof credit of $1372 and a zero roof credit. The change in break-even cost is approximately -$0.34/$W_p$. It varies slightly because the roof credit results in the homeowner who purchases a PV system taking a somewhat smaller loan for the cost of the home, apart from the PV system; hence, he pays smaller interest costs on the home. The tax-deductibility of interest costs means that the change in the break-even cost with and without the roof credit will be dependent on the homeowner's marginal tax rate, which varies from state to state. The anomalously large change in break-even cost with and without the roof credit in Boston is due to the fact that, in Massachusetts, interest costs are not tax-deductible at the state level. Hence, when the roof credit is zero, the effective cost of the loan required is larger for Boston than it is for other locales.

D. GOVERNMENT INCENTIVES

The effects of a number of possible government incentives for solar energy systems are quantified and presented in this section. The PV residential base case assumes that the federal 40% residential and 15% business tax credits end in 1985 and are not extended. In addition, the base-case assumption is that none of the present state solar incentives are in force when the homeowner purchases the PV system in 1986. (An exception is for time-limited property-tax exemptions in Boston, Miami and Phoenix.) The effects on break-even cost of federal and state tax credits and complete property tax exemptions are examined in this subsection. In addition, the effect of substituting expensing in lieu of cost recovery, as provided by the Economic Recovery Tax Act of 1981, is determined.

Table 9. Residential PV System Break-Even Cost Sensitivity to Assumption Concerning Roof Credit, 1980 $/$W_p$ ac

Locale	Break-even Cost: With Credit ($1372 in 1980 $) 1980 $/$W_p$ ac	Break-even Cost: Without Credit, 1980 $/$W_p$ ac	Change in Break-even Price, 1980 $/$W_p$ ac
Honolulu	3.31	2.97	-0.34
Barstow	2.91	2.58	-0.33
Alhambra	2.63	2.30	-0.33
Miami	1.90	1.54	-0.36
Boston	1.81	1.37	-0.44
Denver	1.48	1.12	-0.37
Odessa	1.47	1.13	-0.34
Lincoln	1.09	0.771	-0.32

Table 10 illustrates the impact on break-even costs of extending current solar tax credits at federal and/or state levels through 1986 for the base-case homeowner in Hawaii and Barstow. The federal business tax credit (for PV systems installed for business use) is 15%, with no absolute dollar limit on the amount of credit. The federal residential tax credit (for solar systems installed on one's principal residence) is 40%, with a dollar limit of $4000. The solar tax credit in Hawaii is 10% for both residential and business PV systems, with no dollar limit on either. The allocation of business and residential investment for tax treatment purposes is based on the fraction of the total PV-generated energy that is sold back to the utility during the first year of system operation. The California residential tax credit is 55%, with a $1000 dollar limit. In no case may the combined federal and California residential tax credit exceed 55% of the solar-energy system cost. The California business solar tax credit is, for single-function systems costing less than $12,000, 55% with a limit of $3000. For systems

Table 10. Residential PV System Break-Even Cost Sensitivity to Extension of Present Federal and State Solar Tax Credits (for the Integral-Mount Roof Configuration and a $40,000 per Year Homeowner), 1980 $/$W_p$ ac

	Tax Treatment			
Locale, Tax Treatment	No Tax Credits (Base case)	State Tax Credits Only	Federal Tax Credits Only	Federal and State Tax Credits
Honolulu				
Parallel, Business	3.31	3.53	4.22	4.54
Simultaneous, Business	2.56	2.77	3.14	3.48
Hobby	3.06	4.36	3.63	3.74
Bill Offset	3.33	3.52	3.78	4.00
Barstow				
Parallel, Business	2.91	3.48	3.87	4.58
Simultaneous, Business	2.42	2.97	3.01	3.83
Hobby	2.67	2.90	3.17	3.39
Bill Offset	2.92	3.13	3.38	3.60

costing more than $12,000, the California business solar tax credit is 25%, with no limit.* In all cases, inclusion of the tax credits into break-even cost determinations significantly enhances allowable system costs.

Break-even cost results are quite sensitive to the property taxes paid on the PV system. The manner in which property taxes are computed and the locale-specific property tax rates are given in Appendix C. Table 11 presents data concerning the effect on break-even costs of property-tax exemptions for the base case (Parallel, Business tax treatment, the integral-mount configuration and the $40,000-per-year homeowner). The second column in the table is the effective property tax rate at each site (this is the product of the

Table 11. Residential PV System Break-Even Cost Sensitivity to Property Tax Exemption for PV System (for Parallel, Business Tax Treatment, $40,000-per-year Homeowner, and Integral Mount), 1980 $\$/W_p$ ac

Locale	Property Tax Rate,[a] %	Break-even Cost (Base Case),[b] $\$/W_p$ ac	Break-even Cost With Total Exemption, $\$/W_p$ ac	Change in Break-even Cost, %
Honolulu	0.91	3.31	3.81	15.1
Barstow	1.24	2.91	3.20	10.0
Alhambra	0.87	2.63	2.81	6.8
Miami	2.812	1.90	2.40	26.3
Boston	2.727	1.81	2.09	15.5
Denver	0.42	1.49	1.61	8.1
Midland-Odessa	0.31	1.47	1.53	4.1
Phoenix	2.89	1.42	2.02	42.3
Lincoln	2.00	1.09	1.46	33.9

[a]This is the effective rate, the product of the tax rate and the assessed value of as a percentage of the market value.

[b]Phoenix, Miami, and Boston already exempt PV systems from property taxes for 3, 10, and 20 years, respectively.

*The California allowance for rapid (three-year) amortization of solar energy system cost (net of the state tax credit taken) is not incorporated in this analysis.

property tax rate for the site and the assessed valuation of property as a fraction of the market value). The third column presents the break-even cost under current law. At present, three states exempt solar systems from property taxes, but only for limited time periods. The fourth column shows what the break-even cost would be at each site if the PV system were exempt from property taxes for all years in the study time scope. The last column shows the relative change in the break-even cost between the "exemption for all 30 years" case and the "current law" case. (A relative break-even cost change is determined insofar as greater break-even cost implies a greater system cost and, hence, at a given property tax rate, greater property taxes owed or forgiven.) The value of a PV system property-tax exemption (as captured by the relative break-even cost change) should be directly proportional to the effective property-tax rate.

Figure 10 shows the relative changes in break-even cost for the nine locales as a function of the effective property-tax rate. As expected, the relationship is approximately linear. Phoenix, Miami, and Boston are not "on the line," inasmuch as the PV system in these locales is already exempt from property taxes for 3, 10, and 20 years, respectively. The remaining scatter in the results is due to the fact that property taxes are tax-deductible. Hence, the cost or value of property taxes owed or forgiven is a function of the marginal tax rate of the homeowner, which varies from state to state.

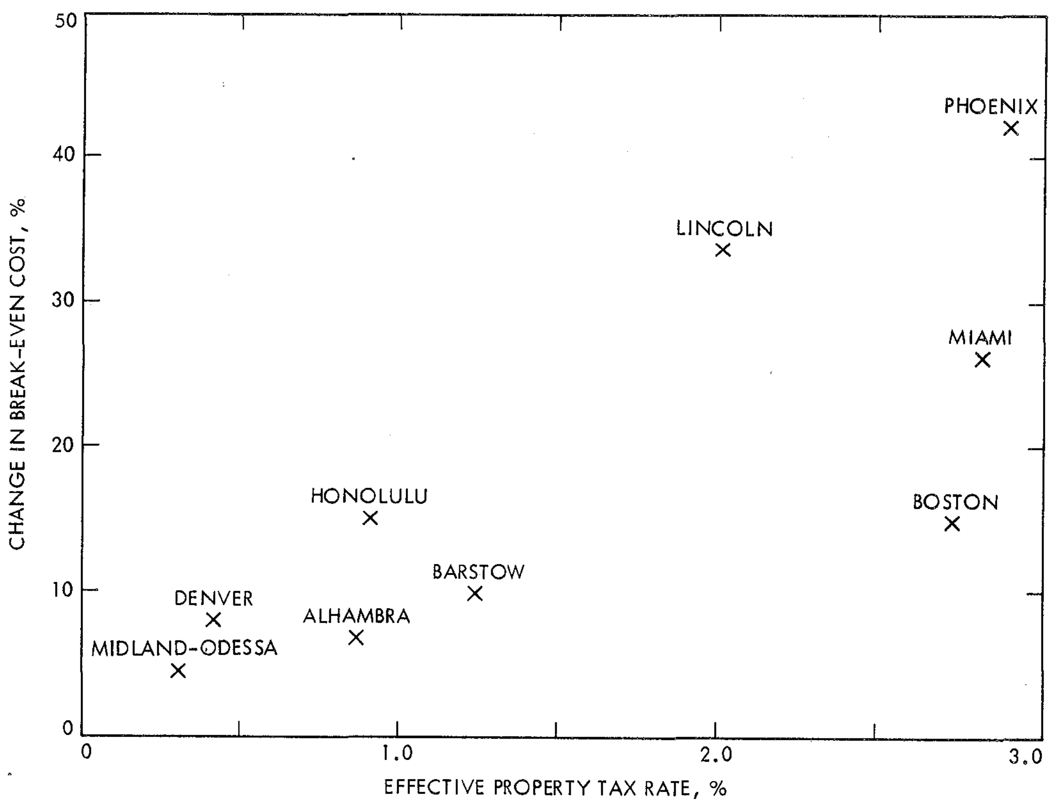

Figure 10. Relative Change in Residential PV System Break-Even Costs as a Function of Property Tax Rate (Parallel, Business Tax Treatment, $40,000-per-Year Homeowner, Integral Mount)

In lieu of cost recovery, the Economic Recovery Tax Act also allows the taxpayer to expense, after 1985 and up to $10,000, the cost of new eligible (i.e., nonstructural) property. This, however, reduces the cost basis for the investment tax credit and for subsequent cost recovery. Under what conditions is expensing financially preferred? Table 12 lists the improvements in break-even cost when expensing is invoked. The key observation is that the incremental break-even costs observed when expensing the maximum amount possible (i.e., for direct-mount modules and Simultaneous, Business tax treatment) is about $0.02/W_p$. Hence, the expensing provision of ERTA is not a significant PV incentive to the typical homeowner. The expensing provision may, however, be helpful in establishing PV system profitability for tax purposes (see Appendix C, IV.E.2).

E. SENSITIVITY ANALYSIS SUMMARY

The sensitivity analyses presented in this report are intended to provide insight into allowable PV system cost variations resulting from changes in important assumptions and parameter values used in the base case. In particular, the effect of different financial assumptions, PV system considerations, and government incentives on residential PV system breakeven costs are explored. These sensitivity analyses thus serve to extend and/or to focus the range of break-even costs for reasonable alternative assumptions.

Table 12. Residential PV System Break-Even Cost Sensitivity to Expensing Provisions of the Economic Recovery Tax Act of 1981, 1980 $/W_p$ ac

	Break-even Cost	
Case, Site, Configuration, Tax Treatment	Without Expensing $/W_p$ ac	With Expensing (Nonstructural Only), $/W_p$ ac
Barstow, Integral Mount, Parallel, Business	2.91	2.92
Barstow, Direct Mount, Simultaneous, Business	2.55	2.55
Honolulu, Integral Mount, Parallel, Business	3.31	3.31
Honolulu, Direct Mount, Simultaneous, Business	2.69	2.67
Phoenix, Integral Mount, Parallel, Business	1.42	1.42
Phoenix, Direct Mount, Simultaneous, Business	0.93	0.95

Subsection III.B presents the results of variations in the financial descriptions used in this study. First, a range of homeowner income levels, homeowner discount rates and loan interest rates and lifetimes are evaluated. Of particular interest are the tax consequences of PV system ownership as a function of homeowner income level. Then the low ($1.42/$W_p$) base-case break-even cost results for Phoenix are modified to incorporate alternative electric utility rate structures (i.e., Southern California Edison Co.) and state tax law (i.e., California). A significant allowable PV system cost increase of almost $2.00/$W_p$ ac is determined for this artificially constructed case study. Finally, the significance of differential recurrent cost expenditures is shown. Using an insurance rate example, an operating cost of 0.05% (of installed capital cost) per year causes approximately a 10% change in PV system break-even cost.

Alternative PV system considerations are evaluated in Subsection III.C. A sensitivity to PV system size is performed that demonstrates the increased allowable cost of smaller-sized residential PV system based on a higher proportion of PV output being used to satisfy homeowner load rather than being sold back to the utility. In the simultaneous mode of interconnection, there is no differential value due to system size since the break-even cost is independent of homeowner load. Annual module degradation rate variations that show a large increase (decrease) in break-even costs for a small percentage of decrease (increase) in annual degradation rate are evaluated. The effects of various residential mounting alternatives (integral, direct and standoff) and tax assumptions are also shown. Energy output variations based on module heating as a function of roof-mounting technique and alternative tax interpretations of structural components for direct-mount modules is included. The base-case integral mount and the direct mount with a nonstructural tax interpretation are shown to have higher break-even costs than the remaining alternatives. The value (in $/$W_p$ ac) of the assumed $1372 roof credit for the integral mount design has been evaluated using the Parallel, Business base case. Allowable costs over all sites are reduced on the order of $0.34/$W_p$ ac if no roof credit can be taken.

The effect of government incentives on residential PV system costs is presented in Section III.D. Solar tax credits at both the federal and state levels are evaluated. Allocations of personal and business solar tax credits are made for each parallel and simultaneous tax alternative. It is shown that these credits raise PV break-even costs to more than $4.00/$W_p$ ac in Honolulu and California. In another sensitivity analysis, the value of a property tax exemption for solar equipment is determined. Property-tax exemptions cause break-even cost increases ranging from approximately 4% to 40%, depending on location. A final sensitivity analysis examines the effect of ERTA on break-even cost. No significant variation from the base-case results were identified.

REFERENCES

1. Smith, J.L., Photovoltaics as a Terrestrial Energy Source, JPL Document No. 5220-15, JPL Publication 81-103, DOE/ET-20356-6, Jet Propulsion Laboratory, Pasadena, California, 1980.

2. Borden, C.S., Lifetime Cost and Performance Model for Distributed Photovoltaic Systems, JPL Internal Document No. 5220-12, August 1981.

3. Davis, R. and Kasper, J. V. V., "Overview of the Alternative Power Systems Economic Analysis Model," American Federation of Information Processing Societies (AFIPS) Conference Proceedings of the National Computer Conference, May 19-22, 1980, Anaheim, California, AFIPS Press, Arlington Virginia, 1980.

4. National Photovoltaics Program Five-Year Research Plan, 1984-1988, U.S. Department of Energy, Washington, D.C., May 1983.

5. Public Utilities Regulatory Policies Act of 1978, Public Law 95-617, 92 Stat. 3117.

6. Hourly Solar Radiation--Surface Meteorological Observations, SOLMET, Vol. 1, Users Manual, TD-9724, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service, National Climatic Center, Asheville, North Carolina, December 1977.

7. Hall, I., et al., Generation of Typical Meteorological Years for 26 SOLMET Stations, SAND 78-1601, Sandia National Laboratories, Albuquerque, New Mexico, August 1978.

8. Yinger, R., The WEST Associates Solar Resource Evaluation Project: Solar Energy Measurements at Selected Sites Throughout the Southwest During 1978, Southern California Edison Co., Rosemead, California, October 1979.

9. Murphy, E.B., and Forman, S.E., Measuring Dirt on Photovoltaic Modules, Document COO-4094-37, Massachusetts Institute of Technology Lincoln Laboratory, Lexington, Massachusetts, March 21, 1979.

10. Hoffman, A.R., and Maag, C.R., Photovoltaic Module Soiling Studies, May 1978-October 1980, JPL Internal Document No. 5101-131, JPL Publication 80-87, DOE/JPL-1012-49, Jet Propulsion Laboratory, Pasadena, California, November 1, 1980.

11. Operations and Maintenance Cost Data for Residential Photovoltaic Modules/Panels Final Report, JPL No. 9950-408, Research and Solar Applications Division, Burt Hill Kosar Rittelmann Associates, Butler, Pennsylvania, July 1980.

12. Southern California Edison Co. Domestic Load Study, 1979, Revenue Requirements Department, Load Research Division, Southern California Edison Co., Rosemead, California, July 1980.

13. Orren, L.H., and Chamberlain, R.G., "A Decision Rule for the Installation of a Solar Electric System," presented at the International Association of Science and Technology for Development Symposium on Modeling, Policy and Economics of Energy and Power Systems -- Alternative Energy Sources and Technology, May 20 to May 22, 1981, San Francisco, California, and at the Western Economics Association Conference, July 3, 1981, San Francisco, California.

14. Lamm, D.S., A Study of Tax Issues Arising From the Purchase and Operation of a Residential Solar Voltic Energy System, JPL Internal Document No. 5220-17, Jet Propulsion Laboratory, Pasadena, California, January 1982.

15. Economic Recovery Tax Act of 1981, Public Law 97-34.

16. Residential Photovoltaic Module and Array Requirement Study, Burt Hill Kosar Rittelmann Associates, Final Report, DOE/JPL-955149-79/1, Jet Propulsion Laboratory, Pasadena, California, June 1979.

APPENDIX A

DESCRIPTION OF DISTRIBUTED PHOTOVOLTAIC SYSTEM BREAK-EVEN COST METHODOLOGY

Distributed photovoltaic (PV) system cost effectiveness is calculated in this report using the Lifetime Cost and Performance (LCP) (Reference A-1) and Alternative Power System Economic Analysis Model (APSEAM) (Reference A-2) sequence of models (see Figure A-1). The first, the LCP model for distributed PV power systems, requires data on PV system performance and cost, and user- and locale-specific information. The PV facility is described by the array electrical design and balance-of-system attributes. Short-circuit current and open-circuit voltage of individual modules at standard test conditions, their electrical configurations within the array, and the system orientation provide the basis for array power-output calculations. Module temperature and efficiency variations as a function of insolation and temperature levels are required to adjust performance estimates for local weather conditions. Balance-of-system efficiencies, both constant and array-output-dependent (e.g., power-conditioning unit efficiency), are also input. Time-varying module degradation and failure rates are required to account for cell cracking, cell mismatch, weathering and yellowing of the encapsulant, and interconnect failure. Input values from current observations of field experiments and from cell failure-rate and array-degradation studies provide initial sources of input data. Balance-of-system down-time rates also are input, although empirical data for long-term balance-of-system performance is extremely limited.

Initial system cost is estimated for each of the components described in the input system design. Projections for installed system costs are based on industry or National Photovoltaics Program analyses; e.g., module prices f.o.b. the factory loading dock may be estimated using the Jet Propulsion Laboratory (JPL) Flat-Plate Solar Array Project (FSA) Standard Assembly-Line Manufacturing Industry Simulation (SAMIS) model (Reference A-3). The cost inputs include all hardware elements plus expenditures for marketing and distribution, field installation and testing, architectural and engineering fees, and warranties. In some instances perceived PV system costs may be reduced if the array is installed on a newly constructed home and the array displaces some amount of otherwise necessary roofing material (commonly referred to as a roof credit). Cost distributions over time are input in base-year dollars and are identified as one of several capital and expense accounts.

The system owner, as described in LCP, is allowed many PV system design and operations-and-maintenance options that influence PV system performance and cost. (All owner-specific financial attributes relating to the calculation of after-tax cost and value are input to the APSEAM financial model, not to LCP). For example, inclusion of the PV system as a part of new-home construction allows for PV-system mounting technique (e.g., integral, direct, or standoff design) and geometric-orientation optimization. Alternative operations and maintenance policies, such as module cleaning and replacement, can be evaluated in terms of their cost, incremental energy output, and dollar value.

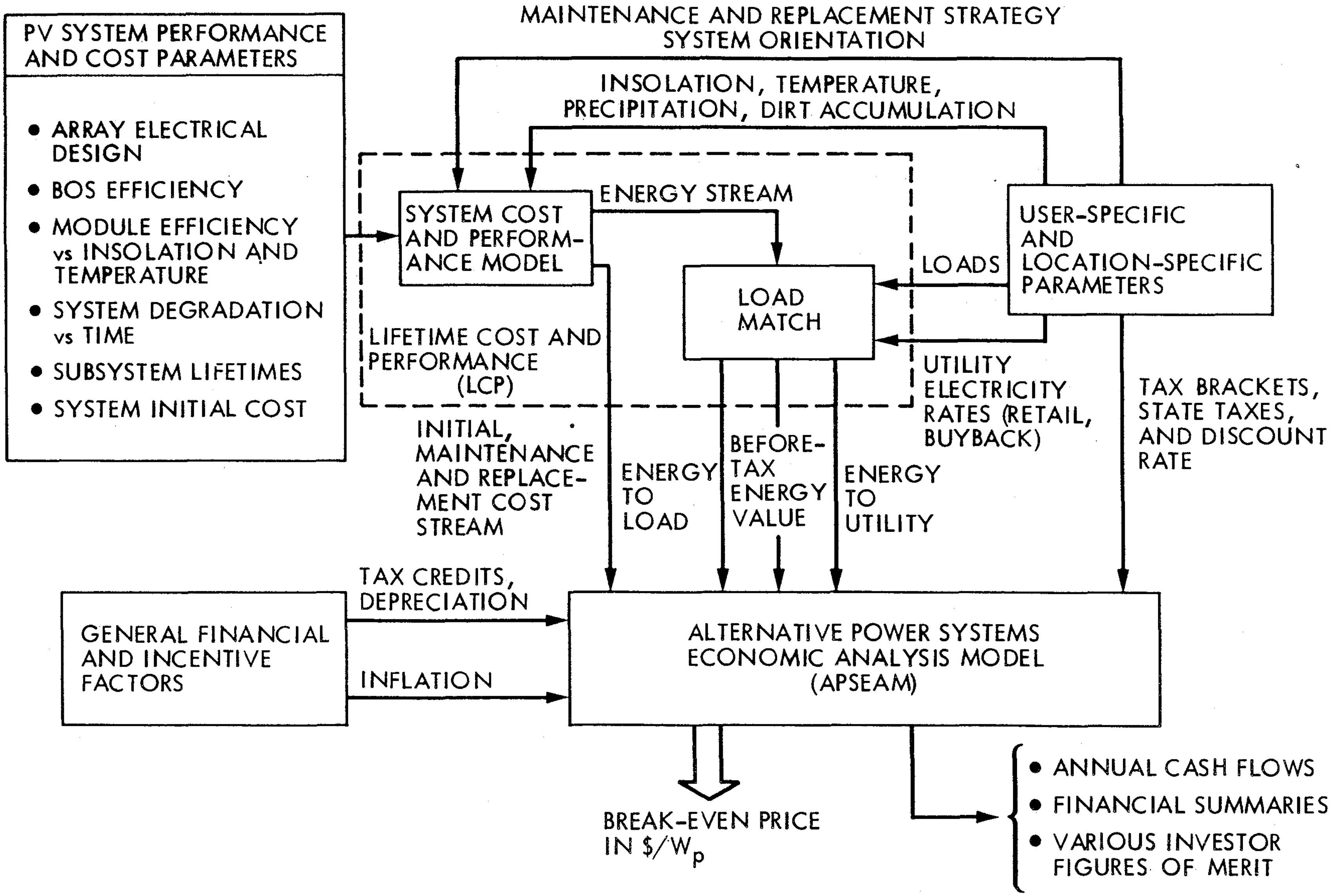

Figure A-1. Distributed Photovoltaic System Economic Analysis Methodology

Locale-specific environmental characteristics are required for the LCP energy-output analysis. Stochastic variations in weather conditions are input to LCP as hourly integrated solar radiation and temperature values from measurements at weather stations at various sites.* Hourly sampling intervals for an entire year are used to capture the effects of diurnal fluctuations in weather conditions, and thus in energy generated by PV systems.

In addition to hourly weather variations, LCP incorporates the effects on power output of dust and dirt accumulation and of precipitation. Local environmental conditions (e.g., pollution and humidity), module cover material, and array orientation and tilt angle affect the rate of power loss and power gain. System power losses (in the absence of scheduled cleanings) are estimated month by month for each site and input to LCP. The increase in power output capability due to cleansing of the modules by rains is also incorporated on a monthly basis.

A description of the PV system owner's interconnection with the utility grid is captured in the electricity demand and utility rate structure inputs.** The time-of-day electricity load of the homeowner is input to LCP for evaluation of energy costs and reduction in energy consumption under the parallel mode of PV-utility interconnection. Weather data and customer load levels are best measured simultaneously for internal consistency. Average hourly customer load profiles are available from many utilities. The LCP model allows for varying customer load profiles over time. Residential customer electricity consumption profiles are irrelevant when all energy generated by the PV system is sold back to the utility.

Current and postulated utility electricity purchase-and-sale interconnection arrangements, as mandated by the Public Utilities Regulatory Policies Act of 1978 (PURPA), are incorporated in LCP. Fixed monthly charges, variable costs per unit of energy, time-of-day rates, and block rate structures (including lifeline provisions) are embedded in most utility-rate schedules. Consistent with current utility billing procedures, LCP requires month-specific input data on rate design. Any additional charges to be borne by the PV owner, such as the monthly cost of an additional meter, liability insurance, or utility grid protection devices, are also included. Utility buy-back rates, determined by the utility net avoided costs of energy (primarily fuel) and capacity (delay or displacement of capital expenditures), are required by LCP for evaluation of both simultaneous and parallel modes of

---

*Available sources of this type of data include Western Energy Supply and Transmission (WEST) Associates (Reference A-4), the National Weather Service (National Oceanic and Atmospheric Administration) (Reference A-5), utility companies and universities.

**Any utility-mandated PV system design, interconnection or operations-and-maintenance requirements, and their associated costs, are incorporated in the PV system and cost input categories discussed above.

PV-utility interconnection. Proposed rates and time-of-day pricing periods (reflecting utility peak, mid-peak and off-peak demand conditions) are collected from individual utilities and are input to LCP as monthly values. Purchase and buy-back rates are at best an indirect measure of the value of electricity to a utility. However, from the perspective of a PV homeowner, they provide a useful basis for a purchase decision.

The LCP procedure first simulates PV-system energy output on an hourly basis, assuming that there is no long-term physical or environmental degradation of system energy output. This simulation combines PV system design characteristics (e.g., array tilt angle, array orientation, module area, and module and balance-of-system efficiency at rated conditions), locale attributes (e.g., geographic location), and power-output variations as a function of local weather conditions and sun position (e.g., for modules) and of array output (e.g., for power-conditioning units), to calculate hourly PV output for the base year.

Energy output for the base year is modified by a second LCP simulation that adjusts for energy losses as a result of module degradation and failure, dirt accumulation, and balance-of-system down time on a monthly basis over all years of PV system operation. Calculation of system energy output at the point of utility interconnection incorporates stochastic module degradation over time, including the effects of electrical mismatch based on the series-parallel connection of modules within the array. The cumulative effects of degradation approximate an exponential reduction in power output over time. The primary parameter for describing the deterioration of PV-array power is the decay in the module short-circuit current under standard test conditions. Within LCP, module short-circuit current and PV array power are related through a model of the current-voltage (I-V) curve of the array. In addition, array power loss due to module failure depends on the time-dependent failure probability, array electrical connections (series-paralleling between modules, bypass diodes, etc.), and the length of time a failed module is out of service. Power reduction due to dirt accumulation is modeled in LCP as an exponential decay, based on field test experience (Reference A-6) with locale-specific monthly power-loss rates and a level (asymptote) that defines the maximum impact of soiling as a power degrader. Most balance-of-system efficiencies are constant in LCP. Power-conditioning-unit efficiency, however, is dependent upon the hourly fraction of peak load driven through it. Balance-of-system down time may vary over the system lifetime and its effect on system energy loss is calculated for each month of the simulation.

Improvements in system performance as a result of operation and maintenance activities (such as cleaning, repair, and replacement) also are evaluated in the monthly simulation. Scheduled cleanings of the array may be performed any number of times during the year to improve optical transmission efficiency. Module replacements over the PV system lifetime may either be calculated or input. Most frequently, module replacements would occur when the PV system power level is calculated to have been reduced to some minimum performance level. The system degrades to this level due to the effects of module degradation, failure, and electrical mismatch. The number of modules to be replaced is calculated based on the level to which system power output must be restored. The second replacement option allows for either individual module or block replacements to be input for any point in time. In addition, cost of replacement and/or repair to balance-of-system components may be input at any point in the simulation, along with a change in the down-time factor, if any. The cost effectiveness of alternative operations and maintenance policies may be derived when all of the performance, cost, and value amounts are causally related in LCP and passed to the APSEAM model for economic evaluation.

Another major analytical procedure within LCP is the calculation of the PV owner's costs and revenues associated with electricity purchase and sell-back, and utility grid interconnection. The LCP load match model determines the (pretax) value of energy generated by the PV system based on its usage.* If the simultaneous mode of PV-utility interconnection is selected, all electricity generated by the PV system is sold to the utility. In this case, the sell-back rates (time of day and monthly or seasonal) and the amount of electricity generated on an hourly basis for each month of the simulation period combine to produce the estimate of value for energy sold back to the utility. The customer's cost of electric service is calculated by the model, though it is unaffected by PV system operations under the simultaneous configuration. Actual utility-specific rate schedules, including time-of-day rates, block rate structures, and lifeline provisions are included. Alternatively, the parallel mode of interconnection may be preferred by the PV system owner. (PURPA allows the qualifying facility to make this choice.) A comparison between PV output and homeowner load is then performed.** LCP calculates the remaining load (differentiated by time of day) and cost of electricity for each month of the simulation lifetime, e.g., 30 years. Load management during the period of system operations is allowed in LCP. As in the simultaneous case, the before-tax energy value is determined by the amount of energy sold back and the sell-back rate structure. The load match information is aggregated to a yearly level and passed to the financial model, which requires it as input.

The final model in the sequence described in Figure A-1 is the financial model (APSEAM; see Reference A-2). APSEAM performs an analysis of PV system financial feasibility by means of a simulation of the flow of funds through a potential investor's books. LCP-derived cost and revenue streams are input to the APSEAM model along with other relevant financial assumptions. APSEAM accounts for financial description (e.g., income level and discount rate),

---

*The LCP load match model calculates pretax financial value indirectly, using utility rate schedules. For utility-owner PV systems, a direct evaluation employing utility production costing and capacity expansion simulation is required.

**A time-of-day comparison is necessary, because PV system value is affected by time-of-day sell-back and purchase rates, and variations in PV performance levels over time due to degradation and failure, or varying customer load levels, will cause non-linear changes in sell-back revenues and electricity purchases from the grid.

locale-specific attributes (e.g., state tax structures, tax credits, and other incentives), and general financial environment (including inflation, federal tax policy as incorporated in the Internal Revenue Code and the Economic Recovery Tax Act of 1981, and federal tax credits or other incentives).

APSEAM provides the code that incorporates the basic accounting relationships. Included are: alternative tax treatments of revenues and expenses, federal and state-specific policies on deductions (e.g., depreciation) and tax credits, provisions for carrying tax credits and operating losses back or forward, differentiation between business and personal use of the PV system, options for system financing, tax tables for income tax calculations (including provisions for indexing or nonindexing tax brackets), and procedures for calculating various figures of merit (e.g., break-even price, net present value, internal rate of return, and liquidity requirements) from the calculated after-tax cash flows. The APSEAM approach is to calculate and compare the after-tax value of investing in a PV energy generation facility versus continuing business as usual (e.g., for the homeowner, purchase of electricity from the local utility). For both the business-as-usual and PV-system capital-investment alternatives, the APSEAM model considers the interaction of revenues and expenses with the homeowner's income level, other deductions, and tax credits to determine state and federal tax implications. Further, the tax consequences of PV system design (e.g., integral versus standoff array design) and mode of PV-utility interconnection are evaluated to determine the appropriate tax treatment of revenues (e.g., deductions above gross income), and expenses (e.g., depreciation on different classes of capital equipment).

The APSEAM methodology begins with the pretax cash flows in nominal dollars for both the business-as-usual and PV investment options. These cash flows reflect revenues minus expenses (treated on a cash, rather than accrual, basis)*. For the PV owner interconnected to the utility in the parallel mode, reduced expenditures for the purchase of grid electricity are incorporated in the pretax expense category. Revenues for either mode of interconnection are generated from the sale of electricity to the utility and equipment salvage at replacement. The tax treatments of these revenues are determined by federal and state law, and APSEAM allows for several interpretations of these (i.e., Business treatment where losses are deductible from gross income, Hobby treatment where the primary investment motive is not profit, and a metering arrangement where sell-back of energy to the utility results in an offset to the homeowner's electricity bill, effected by the PV-utility metering configuration). Expenses related to purchase and to operation and maintenance of the PV system, and cost of utility grid-supplied electricity, are derived in LCP and passed to APSEAM. All financing-related expenses--e.g., principal repayment, interest payments, dividend payments on stock issued (if appropriate)--property taxes, and the down payment are calculated in APSEAM.

---

*An exception to the cash basis for accounting occurs in the case where federal tax payments are deductible from state returns and a search routine is used to calculate the effect of state-federal mutual deductibility. For the base case analysis, only Arizona and Colorado require the use of an accrual basis for calculation of tax effects of mutual deductibility.

APSEAM determines state and federal income taxes in a separate and sequential manner. Federal tax deductibility of state tax payments is explicitly incorporated. The tax calculations involve determination of taxable income (for both the business-as-usual and PV-investment alternatives), calculation of gross taxes (as a function of the amount of and tax rates for ordinary income and capital gains income, deductions, and the other factors that characterize the PV owner's financial status), and computation of net taxes (gross taxes net of applicable tax credits and depreciation). In the case of PV-utility parallel operations where electricity in excess of the homeowner load is sold back to the utility, the sell-back portion may constitute a business activity, and thus the homeowner may qualify for tax deductions on that percentage of his investment. Tax liability is a function of the metering technique and the business, hobby, and/or personal use of the PV system output. After-tax cash flows reflect the pretax amounts less the annual net taxes.

Once the annual after-tax cash flows are derived, a variety of financial figures of merit can be calculated. For the purpose of this report, the primary measure of PV system value is the break-even cost. Additional figures of merit include the net present value, internal rate of return, payback period, years to positive cash flow, liquidity requirements, fractional return on invested capital, and effective (levelized in real terms) cost per unit of energy generated.

REFERENCES

A-1. Borden, C.S., Lifetime Cost and Performance Model for Distributed Photovoltaic Systems, JPL Internal Document No. 5220-12, August 1981.

A-2. Davis, R., and Kasper, J.V.V., "Overview of the Alternative Power Systems Economic Analysis Model," American Federation of Information Processing Societies Conference Proceedings of the National Computer Conference, May 19-22, 1980, Anaheim, California, AFIPS Press, Arlington, Virginia, 1980.

A-3. Chamberlain, R.G., Firnett, P.J., and Horton, M.H., Standard Assembly-Line Manufacturing Industry Simulation (SAMIS) Design Document, Release 3, JPL Internal Document No. 5101-70, Rev. B, Jet Propulsion Laboratory, Pasadena, California, April 1980.

A-4. Yinger, R., The WEST Associates Solar Resource Evaluation Project: Solar Energy Measurements at Selected Sites Throughout the Southwest During 1979, Southern California Edison Co., Rosemead, California, October 1980.

A-5. Hourly Solar Radiation--Surface Meteorological Observations, SOLMET, Vol. 1, Users Manual, TD-9724, U.S. Department of Commerce, National Oceanic and Atmospheric Administration, Environmental Data Service, National Climatic Center, Asheville, North Carolina, December 1977.

A-6. Hoffman, A.R., and Maag, C.R., Photovoltaic Module Soiling Studies, May 1978-October 1980, JPL Internal Document No. 5101-131, JPL Publication 80-87, DOE/JPL-1012-49, Jet Propulsion Laboratory, Pasadena, California, November 1, 1980.

APPENDIX B

PHOTOVOLTAIC SYSTEM, ENERGY OUTPUT, COST, LOCALE, AND UTILITY ASSUMPTIONS AND DESCRIPTIONS

I. TIMING AND ECONOMIC ASSUMPTIONS

The performance of a residential PV system purchased and installed in 1986, beginning operation at the end of 1986*, with a lifetime of 30 years, is simulated. The simulation starts at the beginning of 1986 and stops at the end of 2016. Table B-1 summarizes the timing assumptions.

The home is purchased new by a family of four with an income of $40,000 in 1980 dollars, by a conventional mortgage. Details about the homeowner and the loan are in Table B-2.

Escalation rates for homeowner's income and cost inputs are shown in Table B-3. Homeowner income is assumed to rise 1% faster than the rate of inflation, giving him modest real income growth. All costs are in 1980 dollars and are escalated to the year of expenditure. The most current cost information is used; 1981 or later costs are deflated by 9% per year to 1980 dollars, reinflated as many years by 9% to balance the deflation, and subsequently escalated categorically. Energy costs and revenues are assumed to escalate at 12% annually until the PV system starts operation (1987), and 9% per year subsequently.

II. COST ASSUMPTIONS

The PV system cost assumptions reflect the most current information available at the time this study was conducted (1981). Most of the PV system cost estimates are based on information presented in documents by Burt Hill Kosar Rittelmann Associates (BHKR) (Reference B-1) and General Electric Co. (GE) (Reference B-2). Module and power-conditioner costs derive from the PV Price Goals as of 1981 (Reference B-3) and in-house estimates. These costs are important as a reference point for the break-even costs resulting from this analysis, but the amounts of the initial capital costs do not directly affect the break-even cost calculation. Other ongoing PV system costs, such as for operations and maintenance and PV system interconnection to the utility, affect the break-even cost calculation. When information has not been available, JPL has estimated these costs. In addition, the roof credit derived from the BHKR study is not subtracted from the initial capital costs but is incorporated as a reduction in the purchase price of a PV home as compared with that of a conventional home. Table B-4 presents the cost assumptions used in this analysis.

---

*The system is assumed to come on line on December 31, 1986, for tax purposes. Full energy output is assumed to begin the following day, January 1, 1987.

Table B-1. Timing Assumptions

Base Year for Constant Dollars	1980
Year of First Cost (Start Year)	1986
First Year of Capacity Operation	1987
PV System Lifetime	360 months
End Year (End of System Lifetime)	2016

Table B-2. Homeowner and Loan Description

Family Size	Husband and wife, 2 children
Gross Family Income	$40,000 on Dec. 31, 1986
Source of Income	Entirely from wages
Itemized Deductions From Other Than House or PV System	$4000 on Dec. 31, 1986 ($1000 of this is medical)
Income Tax Return	Married, joint return (Schedule Y)
Discount Rate	10.5%
Loan Rate	14.5%
Down Payment	20%
Lifetime	30 years
Loan Costs	1.5%

Table B-3. Escalation Rates, %

General Inflation	9
Homeowner's Gross Income	
Before Installation	10
After Installation	9
Itemized Deductions From Other Than House or PV System	9
Purchase Price and Sellback Price of Electricity	
Before Installation	12
After Installation	9
Capital Cost	9
Labor Cost	9
Appraised Value	
Capital	9
Land	11
O&M Cost	9
Module Cost	9
Installation Cost	9

ALL of this

START

Table B-4. Baseline Cost Assumptions, 1980 $

Array Structure Cost (including module installation)	$ 2822
5 kVa dc/ac Power Conditioner	1500
Power-Conditioner Marketing and Distribution	500
Miscellaneous Electrical Equipment	156
Balance-of-System Installation Labor	193
Lightning Protection Cost	630
Roof Credit (including labor and overhead)	1372
Module Cost (for 20 modules)	3740
Module Marketing and Distribution	935
Warranty	75
Balance-of-System O&M Cost (every 7 years)	250
Cost per Cleaning	5

III. PV SYSTEM DESIGN AND PERFORMANCE

The PV system used in this analysis was designed by the Jet Propulsion Laboratory (JPL) assuming a 1986 photovoltaic technology. Module size was taken to be 96 x 32 in., the optimum size according to the BHKR study. Cells were assumed to be 4 x 4 in. square with an encapsulated efficiency of 15% and a module packing factor of 90%. One module is then composed of eight parallel strings, each with 24 cells in series. A glass cover plate is assumed, to minimize dirt accumulation and cleaning expenses. This structure gives an open-circuit voltage of 14.4 volts, a short-circuit current of 22.5 amperes, and a maximum power output of 267 watts. A bypass diode is included for each module. Twenty of these modules are needed for a 5-kW_p dc system. The system configuration is two parallel branch circuits of 10 series-wired modules each, to give a maximum system voltage of 144 volts, satisfying normal household voltage requirements. The system is mounted as an integral design, composing approximately 40 square meters of the south-facing roof of the residence. For maximum annual power, the roof is assumed to face due south and to be tilted at the latitude angle of the site. A roof credit for the integral array design is given (derived from BHKR) at installation, which includes a credit for replacing plywood, tarpaper, and red cedar shakes, along with a 20% labor and overhead markup (over BHKR figures) to cover the savings from not having to install a conventional roof for the PV portion. There are no additional credits for succeeding replacements downstream. The power conditioner has an efficiency of 92.3% while it is operating above 24% of peak capacity; below this level, efficiency degrades linearly to 0. For the baseline integral-mount system, a thermal efficiency of 97.5% is included. A balance-of-system efficiency of 95% is also assumed. The PV systems are utility-grid-interconnected and there is no on-site electricity storage.

During the system's 30-year lifetime, degradation and failure of system components can be taken into account in the Lifetime Cost and Performance (LCP) model (Reference B-4). In the base case, modules are assumed to degrade 1% annually. Degradation is assumed to be stochastic and independent for each module. For this analysis, 10 computer runs were made with stochastic module degradation and the resultant system degradation factors over its lifetime were calculated and then averaged. The resulting averaged degradation stream

cont.

is used deterministically in the baseline case and for sensitivity analyses. The baseline (1% module degradation) system degradation stream shows approximately 1.5% degradation annually due to mismatch between modules that have degraded to different power levels. It is assumed that no catastrophic module failures occur in the baseline, nor any wiring or interconnect failures. In addition, no balance-of-system failures are assumed, as the inverter is to be overhauled every seven years (see Balance-of-System O&M cost in Table B-4). System assumptions are summarized in Table B-5.

Table B-5: Photovoltaic System Design Assumptions

Module Short Circuit Current, amps	22.5
Module Open Circuit Voltage, V	14.4
Module Packing Efficiency, %	90
Encapsulated Cell Efficiency, %	15
Irreversible Degradation Rate, %/yr	1
Module Failure Rate	0
Nominal System Size, kW_p ac	4.34
Connector Failure Rate	0
PCU Equipment Function, % (with dropoff at 24% of rated output)	92.3% (rated)
No. of Branch Circuits	2
No. of Modules per Branch Circuit	10
No. of Diodes per Module	1
Area of Module, m^2	1.98
Voltage Drop by Diode, V	0
Integral Mount Thermal Efficiency, %	97.5
Balance of System Efficiency, %	95

IV. LOCALE SELECTION PROCEDURE

The procedure used for selecting locales for the residential break-even cost analysis is presented below. Principles governing this analysis are to: (1) provide continuity with past analytical efforts (e.g., Reference B-3) and (2) extend the PV Program's understanding of the variations in allowable system costs due to variations in location, climate, PV system configurations, and electric utility characteristics.

Consistent with the above objectives, Phoenix, Miami, and Boston are included in the set of locales to be evaluated. In addition, Denver is frequently included in solar-energy system evaluations conducted by the Solar Energy Research Institute, and is also incorporated in this study. A set of criteria has been developed to assist in the selection of additional locales. These are:

(1) Locale reflects weather patterns typical of its region.

(2) Locale has an adequate population base to support a large penetration of residential PV systems.

(3) Primary locales are neither biased against PV nor the best available in a given region. Realism and conservatism is important. If desired, a sensitivity analysis on region-specific best locales may be performed.

(4) Utility has generation capacity of reasonable size.

(5) Utility retail rates are not biased against distributed small power producers (e.g., rates are do not have an exaggerated declining block rate structure).

(6) Residential hourly load profiles are available.

(7) Data can be documented and defended.

Significant constraints and limitations were encountered in the site-selection process. Data availability, quality, and accessibility within the time allotted for this analysis were the major constraints. Hourly weather data are limited to those sites where data collection activities have continued for at least one year. Sources used in this analysis are WEST Associates* and the National Oceanic and Atmospheric Administration, for solar-meteorological data (SOLMET) (1977-1980) and Typical Meteorological Year data. Data on residential customer electricity consumption by time of day were not readily available (in a usable format) from all potential utilities. Utilities selected for this study generally have data in the form of either a total or a typical residential customer electrical load profile by time of day, and many include an adjustment for annual income level, and for household appliances on hand.

A major limitation is the lack of a site in the northwestern part of the country. Available data reflected a poor solar resource and very low utility costs of electric power generation (due primarily to a large amount of available hydroelectric power), giving this region a relatively low priority for residential PV assessment at the time of this study.

The selected locales are listed below. Each has its associated source of insolation and temperature data, a utility grid to which the PV system is interconnected, and a basis for residential customer electrical load. The California Public Utilities Commission has been particularly active in its implementation of the Public Utilities Regulatory Policies Act of 1978 (PURPA). In addition, utility costs of electricity generation are relatively high and weather conditions are favorable to PV in California. Two locales in the Southern California Edison Co. (SCE) service territory were, therefore, chosen: as representative of the Los Angeles metropolitan area, Alhambra, was selected**; the second locale in the SCE territory, Barstow, has a desert environment representing a "best site" consistent with the selection criteria; see (3) above.

---

*Western Energy Supply and Transmission (WEST) Associates Solar Resource Evaluation Project. Project management and reporting is by the Southern California Edison Co.

**Insolation data quality and availability was a prime consideration in the selection of this site.

Selected Sites

Alhambra, California
Barstow, California
Boston, Massachusettes
Denver, Colorado
Honolulu, Hawaii
Lincoln, Nebraska
Miami, Florida
Midland-Odessa, Texas
Phoenix, Arizona

Hawaii has a tropical climate and high cost of utility-generated electricity (due to mostly oil-fired capacity in the grid). This site may be typical of many international applications.

In the Midwest, Lincoln's insolation level is representative of the region, and data from the SOLMET network is available. Lincoln has a relatively large concentration of residential population (for that area of the nation). Furthermore, retail electricity rates are average to above average for the Midwest, buyback rates are higher than average (by 1 to 2.5 cents/kWh) for peak hours, Lincoln Electric has "reasonable" generation capacity, and hourly residential customer load data were available.

Midland and Odessa were selected as a locale to represent the south central region of the United States. Recent SOLMET insolation and temperature data are available for the locale, and this area represents a balance between the more extreme weather conditions to the north and south. Population levels are sufficient, hourly residential load data are available, and utility rates for consumption and sell-back are typical of the area. In addition, the utility believes that it has a progressive attitude toward renewable energy projects.

V. PV ARRAY DIRT ACCUMULATION AND CLEANING ASSUMPTIONS

Site-specific descriptions of energy reductions due to dirt accumulating on the PV array are included for all locations. LCP requires a monthly energy loss rate and a level (asymptote) to which energy losses are limited. In addition, the effects of rain as a restorer of energy output are included. Cleaning the arrays by means of hiring a service has been determined to be not cost effective. Therefore, cleaning by the homeowner at relatively infrequent intervals and at low cost is assumed. Table B-6 summarizes the effects on energy output due to dirt accumulation and cleaning.

Table B-6. Effects of Dirt Accumulation and Cleaning on Residential Photovoltaic System Power Output

Location	Monthly Energy Loss Rate[a], %	Energy Loss Asymptote[a], %	Energy Restoration Level, %: Manual Cleaning	Energy Restoration Level, %: Rain	Annual Number of Manual Cleanings and Rain[a]
Alhambra	3[b]	90	99	97	7
Barstow	2	98	99	99	2
Boston	1	93	100	99	1
Denver	1	95	100	99	12[c]
Honolulu	1	95	100	99	12[c]
Lincoln	1	95	100	99	12[c]
Miami	1	98	100	100	12[c]
Midland-Odessa	3	95	100	98	8
Phoenix	1	95	100	99	5

[a]Entries for Monthly Energy Loss Rate, Energy Loss Asymptote, and Number of Cleanings are designed to be interpreted in a combined sense. For example, the energy loss asymptote for Alhambra will never be achieved in this analysis due to the combined effects of rain and cleaning. The value is simply illustrative. On the other hand, the value for Boston is expected to be achieved during the year.

[b]In summer months the value is 5%.

[c]Energy loss is limited to restoration level due to rain.

VI. UTILITY AND WEATHER DATA

Climatic data collected consisted of a full year of hourly insolation and temperature data for each locale and information outlining the dirt accumulation to be expected for the site (pollution and rainfall level and frequency data). The insolation and temperature data were obtained on magnetic tapes from the SOLMET network and WEST Associates. In choosing the reference year for the insolation data, consideration was given to the availability of data, its robustness and completeness, and correlation with the electricity load data collected for one year. WEST Associates data were considered the most reliable, but its availability was limited to the Barstow, Alhambra and Denver sites. SOLMET sites often have large portions of missing data for any single year, forcing use of Typical Meteorological Year (TMY) data or splicing together good data from more than one year. Where load data was obtained in actual hourly form for a whole year, every attempt was made to obtain insolation data from the same year for correlation. Other climatic data used for establishing the baseline came from the National Oceanic and Atmospheric Administration (Reference B-5) and the Atmospheric Sciences Research Center (Reference B-6). Module soiling data came from Jet Propulsion Laboratory soiling studies (Reference B-7).

Each utility grid has its own purchase rates, sell-back rates, and customer load profiles. For each locale-utility combination selected, the latest information concerning its electricity rates was obtained. Current sell-back rates developed by the utility in response to PURPA were used. If no sell-back rates had yet been developed, the utility's best estimates using their avoided-fuel-cost data were used. Most residential purchase and sell-back rates reflect mid-year 1981 data, and as such are deflated one and a half years (by 9% annually; the factor is 1/1.138) to January 1980 dollars for baseline input (the energy escalation rates then reflect this deflation rather than the pre-installation escalation rate of 12%).

Electricity consumption data were also obtained from the utilities. The preferred format was actual hourly data for a single residence for a full year (corresponding to the year of insolation data) if available. If there was no empirical hourly load data for an entire year, it was approximated by information on typical weekday and typical weekend day data for each of the months of the year. In some cases, group (residential) peak day or system peak day data for each month of the year were used rather than typical weekday and weekend-day. This was done when it was believed that the 1986 new-home buyer--PV-system owner did not fit into the typical customer format. See Table B-7 for information about the sources of the climatic and energy data for each site.

Table B-7. Sources of Site-Specific Data

Site	Sources of Insolation & Temperature Data	Utility	Monthly Residential Load Data
Alhambra	WEST 1979	Southern California Edison Co.	System peak day, 1979
Barstow	WEST 1979	Southern California Edison Co.	System peak day, 1979
Boston	SOLMET TMY	Boston Edison Co.	Group peak day
Denver	WEST 1979	Public Service of Colorado	Hourly 1979
Honolulu	SOLMET 79/80	Hawaiian Electric Co., Inc.	Typ. wkday/wknddy
Lincoln	SOLMET 77/80	Lincoln Electric Utility Co.	Hourly 1980
Miami	SOLMET TMY	Florida Power & Light	Typ. wkday/wkndday
Midland-Odessa	SOLMET 78-80	Texas Electric Service Co.	Typ. wkday/wkndday
Phoenix	SOLMET TMY	Arizona Public Service Co.	Hourly 1978

VII. UTILITY RATE STRUCTURES

Baseline residential customer electricity purchase and sell-back rates used in the LCP-APSEAM analysis are shown in Tables B-8 and B-9. These rates reflect the latest available information (as of September 1981) from the eight utilities, deflated to January 1980 dollars. Deflation was done by half-years: if the rates were effective from October 1980 to March 1981, the deflator was 1.09; if rates were effective from May 1981 to the present, the deflator was $(1.09)^{1.5} = 1.138$. Specific information concerning the basis for the rates presented for each utility can be found in the notes following each table.

Table B-8. Baseline Residential Electricity Purchase Rate Structures (1980 $)

Utility (Site)	Monthly Connect Charge, $	Monthly Consumption Interval	kWh Division	Price, $/kWh
Southern California Edison (SCE)[a] (Alhambra & Barstow)	0.00	1	0-240	0.0493 (all months)
		2	>240	0.0708 (all months)
Texas Electric Service Company(TESCo)[b] (Midland-Odessa)	5.27	1	0-25	0 (all months)
		2	>25	0.0483 (Jan.-Apr.)
				0.0524 (May-Sept.)
				0.0483 (Oct.-Dec.)
Hawaiian Electric Company, Inc. (HEC)[c] (Honolulu)	3.21	1	0-100	0.1065 (all months)
		2	100-300	0.1010 (all months)
		3	300-600	0.0916 (all months)
		4	>600	0.0956 (all months)
Lincoln Electric System (LESCo)[d] (Lincoln)	3.48	1	0-400	0.0383 (all months)
		2	400-1000	0.0348 (Jan.-May)
				0.0535 (June-Sept.)
				0.0348 (Oct.-Dec.)
		3	>1000	0.0218 (Jan.-May)
				0.0535 (June-Sept.)
				0.0218 (Oct.-Dec.)
Boston Edison (BE)[e] (Boston)	2.24	1	0-15	0.0464 (all months)
		2	15-50	0.1109 (all months)
		3	50-100	0.0960 (all months)
		4	100-150	0.0868 (all months)
		5	150-300	0.0834 (all months)
		6	300-350	0.0800 (all months)
		7	350-384	0.0800 (Jan.-June)
				0.0974 (July-Oct.)
				0.0800 (Nov.-Dec.)
		8	384-1000	0.0914 (Jan.-June)
				0.1088 (July-Oct.)
				0.0914 (Nov.-Dec.)
		9	>1000	0.0639 (Jan.-June)
				0.0813 (July-Oct.)
				0.0639 (Nov.-Dec.)
Arizona Public Service (APS)[f] (Phoenix)	8.77	1	0-400	0.0434 (Jan.-Apr.)
			0-1500	0.0440 (May-Oct.)
			0-400	0.0434 (Nov.-Dec.)
		2	>400	0.0410 (Jan.-Apr.)
			>1500	0.0517 (May-Oct.)
			>400	0.0410 (Nov.-Dec.)
Public Service Company of Colorado (PSCC)[g] (Denver)	2.90	1	0-30	0 (all months)
		2	30-100	0.0714 (all months)
		3	100-1000	0.0521 (all months)
		4	>1000	0.0381 (all months)
Florida Power & Light (FP&L)[h] (Miami)	2.81	1	0-750	0.0580 (all months)
		2	>750	0.0632 (all months)

NOTES:

a. The Southern California Edison Co. Rate Schedule D (Residential Service) became effective in mid-1981 with the increase of August 6, 1981 in the Basic Energy Charge. The applicable rates are the basic lifeline allowance of 240 kWh for all customers and the Other Domestic Service rate for all excess usage. An excess lifeline allowance is applicable to customers with electric water heating and customers with electric space heating or air conditioning in specific climatic zones. Since the load used in this study is a district-wide average of SCE's residential service, excess lifeline is believed to be inapplicable. The mid-1981 rates were deflated by $(1.09)^{1.5} = 1.138$ to January 1980 dollars.

b. The Texas Electric Service Co. rate schedule became effective in October 1980, incorporating the fuel cost adjustment (FCA) of August 1981, and is applicable to standard residential customers without electric space heating and thus without the winter discount for electric space heating. Fuel-cost adjustments change monthly with the difference added or subtracted from the previous total charge. The rates entered in LCP include average fuel cost adjustments for the winter and summer seasons. The winter rate includes the average energy cost adjustment (ECA) for the months January-April (also applied to October-November) and is deflated by 1.09 to January 1980 dollars. The summer rate contains the average FCA for the months May through August (applicable to September also) and is deflated by 1.138 to January 1980 dollars.

c. The Hawaiian Electric Co., Inc., rate schedule became effective November 1, 1980. The most recent ECA, effective April 2, 1981 and Basic Fuel Charge beginning on July 15, 1981 (a standard adjustment associated with ECA), have been added to the total energy charge. Revenue taxes of franchise, public utility and PUC fee are included. These rates were deflated by 1.138 to January 1980 dollars.

d. Lincoln Electric System's rate schedule became effective January 1, 1981. It has no fuel adjustments during the year. The rates were deflated by 1.09 to January 1980 dollars.

e. The Boston Edison Co. rate schedule became effective October 17, 1980, with an ECA increase effective January 1981. Monthly changes in the ECA are not captured by the rates presented here. The rates were deflated by 1.09 to January 1980 dollars.

f. Arizona Public Service's rate schedule became effective February 3, 1981, incorporating an ECA applicable May 1, 1981. The tax-adjustment component of total energy charge includes sales, city, and state taxes plus regulatory assessment for Phoenix as of October 1980. The rates were deflated by 1.138 to January 1980 dollars.

g. The Public Service Co. of Colorado rate schedule became effective January 7, 1981; it included a two-stage base-rate increase totaling 15.13%. Also included were the average Energy Cost Adjustment for the year and a charge for franchise and sales taxes. Rates are applicable to underground residential service and have been deflated by 1.09 to January 1980 dollars.

h. The Florida Power & Light Co. rates as of July, 1981, included the latest monthly ECA and a Conservation Adjustment. The rates were deflated by 1.138 to mid-1981 dollars.

N.B: (1) As far as is known, rates do not include franchise and municipal taxes or other fees, if applicable to the utility, unless otherwise noted.

(2) All rate schedules were obtained either by telephone conversation with utility rate specialists or by mail. Recent updates and validation of rates were conducted by telephone.

Table B-9. Baseline Residential Electricity Sell-back Price Structures

Utility (Locale)	Time-of-Day Generation Interval[a]	Price, 1980 $/kWh
Southern California Edison[b] (Barstow and Alhambra)	1 (peak)	0.0677 (all months)
	2 (shoulder)	0.0624 (all months)
	3 (off-peak)	0.0606 (all months)
Texas Electric Service Co.[c] (Midland-Odessa)	1 (all)	0.0156 (Oct.-Apr.)
		0.0211 (May-Sept.)
Hawaiian Electric Co., Inc.[d] (Honolulu)	1 (all)	0.0747 (all months)
Lincoln Electric Service[e] (Lincoln)	1 (peak)	0.0220 (Oct.-May)
		0.0308 (June-Sept.)
	2 (off-peak)	0.0118 (Oct.-May)
		0.0140 (June-Sept.)
Boston Edison[f] (Boston)	1 (peak)	0.0456 (Dec.-Feb.)
		0.0538 (Mar.-May)(Sept.-Oct.)
		0.0533 (June-Aug.)
	2 (off-peak)	0.0249 (Dec.-Feb.)
		0.0303 (Mar.-May)(Sept.-Oct.)
		0.0371 (June-Aug.)
Arizona Public Service[g] (Phoenix)	1 (peak)	0.0217 (Nov.-Apr.)
		0.0283 (May and October)
		0.0348 (June-Sept.)
	2 (off-peak)	0.0143 (Nov.-Apr.)
		0.0151 (May and October)
		0.0158 (June-Sept.)
Public Service Co. of Colorado[h] (Denver)	1 (all)	0.0275 (all months)
Florida Power and Light[i] (Miami)	1 (peak)	0.0545 (all months)
	2 (off-peak)	0.0492 (all months)

NOTES:

a. The generation interval (GI) hours change from season to season and from utility to utility. The hours for each utility are as follows:

SCE:	GI-1	Nov.-Apr. (5:00 p.m.-10:00 p.m., weekdays)
		May-Oct. (12:00 a.m.-6:00 p.m., weekdays)
	GI-2	Nov.-Apr. (8:00 a.m.-5:00 p.m., weekdays)
	GI-3	All months (10:00 p.m.-8:00 a.m., weekdays; all weekend hours)
TESCo:	GI-1	All months (all hours)
HEC:	GI-1	All months (all hours)
LESCo:	GI-1	Oct.-May (9:00 a.m.-8:00 p.m., weekdays)
		June-Sept. (11:00 a.m.-9:00 p.m., weekdays)
	GI-2	All other hours
BE:	GI-1	All months (9:00 a.m.-8:00 p.m.)
	GI-2	All months (all other hours)
APS:	GI-1	Nov.-May (7:00 a.m.-10:00 p.m., weekdays and weekends)
		June-Oct. (9:00 a.m.-10:00 p.m., weekdays and weekends)
	GI-2	All other hours
PSCC:	GI-1	All months (all hours)
FP&L:	GI-1	Nov.-Mar. (6:00 a.m.-10:00 a.m., 6:00 p.m.-10:00 p.m., weekdays)
		Apr.-Oct. (12:00 a.m.-9:00 p.m., weekdays)
	GI-2	All other hours

b. Southern California Edison's sell-back rates are derived from the company's current (Interim Proposal) Schedule of Avoided Cost showing avoided costs of energy based on recorded fuel purchase prices for the quarter ending in July 1981. These rates represent the time-of-day (TOD) energy component only and do not include a PV capacity credit.

It is believed that these rates provide a more realistic long-term indicator of PV value than does SCE's current policy for small power producers: that of trading off kWh produced one for one against the customers' monthly kWh purchased, in effect making the sell-back price equal the (nonlifeline) purchase price (currently there is no lifeline service for small power producers). The rates are deflated by 1.138 to January 1980 dollars.

c. Texas Electric Service Co. sell-back rates are an experimental tariff based on the avoided cost of fuel. The proposed tariff automatically sets the rate equal to the monthly ECA component of residential purchase rates. The average ECA was computed for the winter and summer seasons. The winter rate is the average of the January-April 1981 ECAs (applied also to October-December) and the summer rate is the average of the May-August 1981 ECAs (applicable also to September). These rates were deflated by 1.09 and 1.138, respectively.

d. The Hawaiian Electric Co. sell-back rate is temporary, based on their marginal energy cost. The Hawaiian PUC has recently established rules to develop final rates based on "the incremental average cost of energy, including purchased power." Rates are not expected to deviate much from the temporary rate for all kWhs of power sold back. The mid-1981 value was deflated by 1.138 to January 1980 dollars.

e. Lincoln Electric Service Co. sell-back rates were obtained in mid 1981. They are seasonal, by TOD rates, based on the avoided cost of generating 100 kW of energy in 1981. The Nebraska PUC has made final rulings for sell-back rates that are currently being developed by the utility. The existing rates have been deflated by 1.138 to January 1980 dollars.

f. Boston Edison's sell-back rates have been estimated in house, using the company's projected avoided energy costs for 1981. These seasonal and by-TOD rates were deflated by 1.09 to January 1980 dollars. The state PUC has recently established the methodology to calculate final rates based on the average incremental costs of energy and including some capacity payment. Boston Edison expects to propose rates in October 1981, giving an optional TOD rate, quarterly fuel adjustments and a once-per-year capacity adjustment.

g. Arizona Public Service Co. sell-back rates are the company's estimated avoided energy costs based upon 100 MW purchased hourly from qualifying facilities. They are seasonal and time-of-day-divided. As APS's summer was May 16 to October 15 and winter October 16 to May 15, these sell-back rates for May and October were taken to be the average of the summer and winter rates. The rates were presented in 1980 dollars and thus were not deflated.

h. The Public Service Co. of Colorado sell-back rate is a temporary rate based on the avoided cost of energy in 1980. Set for all kWhs sold back, the rate is considered by the utility to be at the lower end of the values expected in the final rates, which could vary by season and TOD. The upper limit is estimated to be at least 2¢ (66%) higher. The state PUC has not yet issued a final ruling on the establishment of sell-back rates but is expected to do so by the end of the year. The current rate was deflated by 1.09 to January 1980 dollars.

i. Florida Power & Light Co. sell-back rates are by TOD based on avoided fuel costs in 1981. The Florida PUC proposed rates are greater than current retail rates for FP&L, based primarily on their avoided cost of oil. FP&L has resubmitted rates for approval based on the average cost avoided of all fuel, determined for a specific time period. TOD rates will be optional. The values have been deflated by 1.138 to January 1980 dollars.

REFERENCES

B-1. Residential Photovoltaic Module and Array Requirements Study, Final Report, DOE/JPL-955149, Jet Propulsion Laboratory, Pasadena, California, June 1979.

B-2. Regional Conceptual Design and Analysis Studies for Residential Photovoltaic Systems, Vol. II, General Electric Space Division, General Electric Co., January 1979.

B-3. National Photovoltaics Program Multi-Year Program Plan, JPL Internal Document No. 5220-9 (Draft), Jet Propulsion Laboratory, Pasadena, California, 1980.

B-4. Borden, C.S., Lifetime Cost and Performance Model for Distributed Photovoltaic Systems, JPL Internal Document No. 5220-12, August 1981.

B-5. Climate of California, Climatography of the United States No. 60; National Oceanic and Atmospheric Administration, Environmental Data Service, National Climatic Center, Asheville, North Carolina, August 1977.

B-6. Northeast Solar Energy Meteorological Research and Training Site, Monthly Solar Climatological Summary, January-February, March 1980, ASRC-SUNY Publication No. 753, Atmospheric Sciences Research Center, Albany, New York, 1980.

B-7. Hoffman, A.R., and Maag, C.R., Photovoltaic Module Soiling Studies, May 1978-October 1980, JPL Document No. 5101-131, JPL Publication 80-87, DOE/JPL-1012-49, Jet Propulsion Laboratory, Pasadena, California, November 1, 1980.

APPENDIX C

ECONOMIC MODEL AND BASE-CASE FINANCIAL ASSUMPTIONS

I. HOMEOWNER BREAK-EVEN COSTS

A case-study approach has been taken in which a hypothetical family of four is assumed to buy a new home in one of nine locations in the United States in 1986. The family has the option of buying the new home with or without a roof-mounted PV system. The flow of funds through the homeowner's books over the next 30 years is projected for each of these alternatives and evaluated in the Alternative Power Systems Economic Analysis Model (APSEAM) (Reference C-1). It is assumed that there is no real increase in any of the cost-and-revenue elements associated with the investment beyond 1986. If the family selects the home with the PV system, the PV-produced electricity as calculated by the Lifetime Cost and Performance (LCP) model (Reference C-2) is either used to satisfy part of the electricity requirements of the home, with the local utility supplying all remaining electricity requirements, or is all sold back to the utility, with the electricity requirements of the home being met exclusively by purchases from the local utility. Note that this analysis does not address the question of the financial feasibility of retrofitting an existing home with a PV system. Also note that all dollar amounts referred to herein are 1980 dollars, unless specified otherwise.

II. BASE-CASE FINANCIAL ASSUMPTIONS

A. Cash-Flow Timing Convention

Within APSEAM (Reference C-1), all cash transactions (expenses or revenues) occur at the end of the year. They are assumed to occur using the January 1 value of the following year's dollars. Thus, expenses and revenues in 1990 are assumed to be paid and received on December 31, 1990, in January 1, 1991 dollars. LCP uses monthly information in determining the costs and revenues associated with PV system purchase and operation, and aggregates this information to the yearly level before passing it to APSEAM.

B. General Economy

The standard rate of inflation is assumed to be 9% and to remain constant over time. The escalation rate for capital equipment and labor is assumed to be equal to the inflation rate. The escalation rate of the appraised value of property improvements is assumed to be 9% and that of land is assumed to be 11%. Note that in California the appraised value escalation rate is limited by law to 2% per year. The price of electricity is assumed to escalate at 12% per year until 1986, the year of initial operation, and at 9% thereafter.

C. Case Study Specific Assumptions

1. Financial Lifetime: Study financial lifetime is 30 years.

2. Family size: Four: husband, wife, two children.

3. Timing: The home, with or without the PV system, is assumed to be purchased in 1986. The home is occupied and the PV system is operative December 31, 1986. The PV system is maintained to last for 30 years.

4. Homeowner Financial Characteristics

   a. Homeowner types. Four homeowner types are considered, defined by their income levels, their tax deductions (apart from those associated with the home and the PV system), and the prices of the homes they purchase.

      (1) Income levels: The four income levels considered were \$20,000, \$30,000, \$40,000 and \$50,000. These are assumed to escalate at 10% per year until 1987, and at the inflation rate (9%) thereafter.

      (2) "Other" Deductions: These are the deductions apart from the interest on the home loan, with or without the PV system, the property taxes paid, the federal and state income taxes paid, and sales taxes paid. These dollar amounts are for 1986 and beyond. They are assumed to escalate at the rate of inflation (9% in the base case).

         (a) Federal level: The homeowner's itemized "other" deductions are assumed to be tied to his income level. For the \$40,000-per-year homeowner, the "other" deductions are \$4000. For the \$20,000, \$30,000, and \$50,000 homeowner, they are \$2000, \$3000, and \$5000, respectively. These deductions include \$1000 in excess medical deductions (i.e., in excess of the 1% of adjusted gross income exclusion for medicine and drugs and of the general 3% of adjusted gross income exclusion). These deductions are assumed to escalate at the same rate as the homeowner's taxable income. The personal exemption is \$4000 (as calculated in Federal Schedule TC). This amount remains fixed until 1985 and is indexed thereafter. The \$3400 exclusion for married couples (Form A) is assumed to remain fixed until 1985 and to be indexed thereafter. Hence, in 1986, the \$40,000 homeowner's excess itemized deductions (line 41 of schedule A and line 33 of Form 1040) are, in 1986 dollars,

$$\$4000\ (1.09)^7 - \$3400\ (1.09)^2 \text{ or } \$3273$$

His personal exemption is $(\$4000)(1.09)^2$

         (b) State level: The "other" tax deductions at the state level track those at the federal level, with minor adjustments reflecting the tax codes

Table C-1. "Other" State Income-Deductions and Tax Credits

	"Other" Deductions	"Other" Tax Credits
Texas*	NA	NA
Arizona	$9952	0
California	4000	84
Colorado	8204	0
Massachusetts	6400	0
Hawaii	8000	0
Florida*	NA	NA
Nebraska	--	112

of the individual states. These "other" state deductions and other state tax credits for the $40,000 homeowner for the states considered are shown in Table C-1. Part VIII of this Appendix contains the details of their calculation as well as the values for other homeowner income levels.

(3) Home prices (apart from the cost of the PV system): Home prices are assumed to vary with income level. The $40,000-per-year family that does not purchase a PV system is assumed to purchase a $100,000 home. The $100,000 home consists of $20,000 in land costs and $80,000 in property improvement costs. For the other homeowner income levels, the home costs are shown in Table C-2.

Table C-2. Home Costs

Homeowner Income Level	Land Costs	Improvement Costs	Total Home Cost
$20,000	$20,000	$ 30,000	$ 50,000
30,000	20,000	55,000	75,000
40,000	20,000	80,000	100,000
50,000	20,000	105,000	125,000

For all PV roof configurations except the standoff design, the cost of the home to the homeowner who chooses to purchase a PV system is slightly less than that to a homeowner who does not, for it has a hole in

*Not applicable; these states have no personal income tax.

the roof (for installation of the integral-mount PV system). This reduced cost reflects the cost of roofing materials and of installation of the roof. The roof credit is assumed to be $1372 for the baseline integral mount design. Hence, the manner in which the roof credit is incorporated into the analysis is through the home cost.

b. Sources of Income. The source of the family's income is assumed to be wages and salaries only. Dividend and interest income is explicitly excluded. This assumption greatly simplifies the tax treatments at the state levels, since various states allow varying amounts of exclusions, etc., with respect to interest and dividend income. (See Part VIII for specific assumptions and additional constraints concerning the nature of the income of the homeowner in various states.)

c. Homeowner Discount Rate. The homeowner's after-tax discount rate is assumed to be 10.5%, and to remain constant over all years in the project's financial lifetime and across all homeowner income levels. The corresponding pretax discount rate is a function of the homeowner's marginal combined (state and federal) tax rate. In this analysis, the pretax discount rate varied from 14% to 19% across all states and income levels considered.

5. Home Purchase Financing. The homeowner is assumed to put 20% down on the home and to finance the remaining cost with a 30-year, constant-payment, mortgage-type loan at a rate of 14.5%.* First-year (administrative) loan costs are assumed to be 1.5% of the loan amount and to be tax-deductible.

6. PV System Financing. If a PV system is purchased, it is assumed to be financed in exactly the same manner and at the same interest rate as the home purchase is financed.

7. Recurrent Costs.

a. Insurance for the PV System: The cost of insuring the PV facility is explicitly incorporated as a yearly cash expense. It commences on January 1 of the first year of operation of the PV system (1987). The cost of insuring the PV system during the construction period is assumed to be borne by the builder and to be included in the PV system price. An annual insurance rate of 0.5% of the installed cost is assumed. This insurance cost escalates yearly at the standard rate of inflation. The annual cost of insuring the home (apart from the PV system) is assumed to be identical whether a PV system is or is not placed on the roof. Hence, it is not spelled out as an explicit cash flow item.

*The assumption of a fixed 14.5% mortgage rate is consistent with the baseline choice of a fixed 9% inflation rate.

b. Cleaning, inspection, and replacement costs for the PV system: These annual cost items are determined by the LCP model and passed to APSEAM for incorporation as yearly cash expenses.

c. Electricity Costs: The homeowner is assumed to pay for connection to the local utility grid (customer charge) and for actual electricity consumed. Residential utility rate schedules are assumed to apply in all cases. The rate structure can be based on time-of-day rates or on consumption levels (e.g., lifeline rates). LCP calculates the cost of purchased electricity on a monthly basis.

d. Sell-back Electricity Revenues: The pretax value of the electricity sold back to the grid is calculated by LCP and is a function of the utility's marginal cost of electricity (approximated here by their proposed buy-back rates under the Public Utilization Regulatory Policies Act of 1978 (PURPA) or avoided fuel costs by time of day) and the amount of energy sold back (by time of day).

e. Property Taxes: Location-specific property tax rates on land and improvements are used. In some states, the solar investment is assumed to be exempt from property taxes for all or part of the period considered in the study. Part VII lists the state-specific property tax rates and assumptions concerning solar-energy system exemptions. Massachusetts, Florida, and Arizona are some of the states that exempt solar-energy systems from property taxes for a specified number of years. However, since property taxes paid are a tax deduction, the exemption serves to increase state and federal income taxes. Thus, the value to the investor of that exemption is less than its "nominal" value. It is allocated among the state government, the federal government, and the taxpayer.

f. Taxes Paid:

(1) State level: The homeowner's net state taxable income is defined as his "other" state taxable income plus his sell-back revenues minus his "other" state deductions minus all applicable tax deductions associated with the home and the PV system, minus all special deductions particular to specific states (for example, in Massachusetts, social security taxes paid are deductible), minus federal taxes paid (for those states such as Arizona and Colorado that allow federal taxes paid as a state tax deduction),* minus property taxes paid. State tax tables for a married couple filing a

*See Part IX for an expanded explanation of the deductibility of state taxes paid on the federal tax return and the deductibility of federal taxes paid on the state tax return.

joint return are then used to determine state taxes owed. State tax tables are assumed to be indexed with inflation. State taxes owed are decremented by state tax credits to arrive at the state taxes paid. The state-specific tax tables and assumptions with respect to deductions and credits are shown in Part VIII. It is assumed that all states except Massachusetts will adopt, by 1986, the federal cost recovery and expensing legislation.

(2) Federal level: The homeowner's net federal taxable income is defined as his "other" federal taxable income plus his sell-back revenues minus his "other" federal deductions, minus all applicable tax deductions associated with the home and the PV system, minus state taxes paid,* and minus property taxes paid. Federal tax tables for a married couple filing a joint return (Schedule Y) are then used to determine federal taxes owed. Federal tax tables are assumed to be indexed with inflation. Federal taxes owed are then decremented by federal tax credits to arrive at the federal taxes paid.* The federal tax tables used and specifics of federal deductions are shown in Part VIII. (This analysis incorporates the relevant provisions of the Economic Recovery Tax Act of 1981. These are outlined in Part XI.)

III. UTILITY INTERCONNECTION AND TAX TREATMENT ALTERNATIVES

The tax treatment of the revenues and costs associated with owning and operating the PV system provides the structure that defines the major base cases evaluated in this analysis. For tax purposes, the presence or absence of a profit motive for owning and operating the PV system and the manner in which the system owner interconnects to the utility grid determines the tax treatment. Four different interpretations are described below. In all cases, the state and federal solar tax incentives are excluded. The federal investment tax credit, for eligible property, is fixed at 10%.

---

*If tax credits cannot be realized in any given year due to insufficient income-tax liability, these are carried forward. Current federal law allows a 15-year carryforward. (Under previous law, it was seven years.) If they are not realized after 15 years, they are completely lost. The only tax credit assumed is the federal 10% investment tax credit and, as applicable, the state investment tax credit (e.g., 2.5% in Colorado); the nonstructural components (Section 38 property) of the PV investment used in a trade or business are eligible for this credit. The nonstructural components of the PV system are assumed to be 5-year property. The first $10,000 of any business investment can be expensed in the year of investment. Amounts expensed are not eligible for the investment tax credit or for cost-recovery depreciation. Expensing is not done in this analysis. It has a negligible effect on break-even cost results.

A. Parallel, Business Base Case

In this case, the PV system's energy output is used to satisfy the homeowner's coincident electricity requirements and the remainder of the PV output is used for sell-back to the electric utility. Parallel, Business assumes that PV output in excess of the homeowner's coincident demand for electricity is sold back to the utility, and the homeowner receives taxable income for his product. The homeowner is assumed to operate his PV system as a business and costs in excess of revenues can be applied against other income of the homeowner.

1. Allocation Algorithm. The ratio of the energy sold back to the utility grid to the total energy produced by the PV system defines the business fraction of the total PV system investment. This ratio varies from year to year. Calculation of this factor enables the initial PV investment to be decoupled into a "business" investment and a "hobby" investment. (See Case D below.) The business investment is assumed to be equal to the product of the total PV system cost and the business fraction in the first year of operation. The remaining PV system cost is the hobby investment. Thus, the first-year business fraction is used to allocate expenditures eligible for tax credits. The first-year business fraction is also used to allocate annual operations and maintenance costs between business and hobby costs.

2. Tax Credits. The business investment is eligible for the investment tax credit. Nonstructural components of the PV system are eligible for the 10% federal investment tax credit and the state investment tax credit, if applicable.

3. Tax Deductions. Interest costs, property taxes, and sales taxes are allowable in full. The business fraction of the total costs of operating and maintaining the PV system are allowable deductions. The business fraction of the total PV investment can also be depreciated. These deductions are recorded, along with the revenues from the sale of electricity to the grid, on Schedule C (and on the analogous state forms). Deductions in excess of revenues can be applied against other taxable income of the homeowner (and can thus serve to reduce the homeowner's taxable income.)

B. Simultaneous, Business Base Case:

The homeowner who invests in a PV system and who chooses to sell all of his PV-produced electricity to the grid will use the simultaneous mode of interconnection. The operation of the PV system will be for the purpose of generating revenues. This homeowner is, therefore, considered to be making a business investment, and the following tax-related considerations apply:

1. Tax credits. The non-structural components of the PV system are eligible for the 10% federal investment tax credit and the state investment tax credit, if applicable.

2. Tax deductions. The homeowner is allowed to deduct all ordinary and necessary expenses associated with owning and operating the PV system. Also included as a tax deduction is cost recovery (depreciation) of the PV system. The structural components are treated as 15-year property. The non-structural components are treated as 5-year property. The deductions may exceed revenues generated and may be used to reduce other taxable income of the homeowner.

C. Hobby Base Case

If the operation of the PV system is determined not to be a pursuit carried on for profit, then the PV investment is assumed to be a hobby investment for tax purposes. The PV system is connected to the utility grid in the parallel mode of interconnection so that the residential load is preferentially served by the PV system and surplus electricity is sold back to the utility grid. The homeowner is not eligible for any investment-tax credit and he follows Hobby rules in completing his income tax return. These rules prohibit the homeowner from using losses to offset income from other sources. Expenses of the hobby activity may be deducted only to the extent of earnings from the hobby activity (in this case, sellback revenues) and only in the following order: First, amounts allowable as deductions during the tax year that would be allowable whether or not the activity giving rise to the deductions was engaged in for profit, are allowable in full. These include, for example, interest and taxes. Second, other expenses allowable as business expenses for an activity engaged in for profit, but only if such deductions do not result in an adjustment to the basis of property, are allowed only to the extent that the gross income from the activity exceeds the deductions allowed or allowable under the first category. Third, depreciation and other deductions that decrease the basis of property are allowed only to the extent that the gross income from this activity exceeds the deductions allowed or allowable under the first and second categories.

D. Bill Offset Base Case:

In another potential PV-utility parallel interconnection arrangement, excess PV-generated electricity is routed back to the utility and the meter is ratcheted backward, based on the value of that energy to the utility. In effect, this is seen as an offset to the homeowner's utility bill. The assumption is made that the value of the PV-generated electricity is less than the homeowner's utility bill in any billing period. The value of the PV-generated electricity is not taxable income in this case, and there are no PV system-related deductions (other than interest and taxes) taken by the homeowner.

IV. MAJOR STUDY ASSUMPTIONS:

Below are listed the major assumptions made with respect to the financial aspects of this analysis. Where appropriate, the basis for these assumptions, or the consequent limitations on the range of applicability of the study results, is presented.

A. Tax Credits

The federal investment tax credit applies to Section 38 property. Section 38 property includes depreciable or amortizable property having a useful life of three years or more and includes tangible personal property and other tangible property (not including a building or its components) used as an integral part of production of, among other things, electrical energy. Section 38 property in the 5-year investment class is eligible for a 10% investment tax credit. In the analysis, all nonstructural PV property is assumed to be in the 5-year investment class. Hence, in this analysis, the 10% federal investment tax credit applies only to the nonstructural portion of the business part of the PV investment. No other federal or state solar tax credits or incentives (e.g., rapid amortization in California and Massachusetts) are assumed for the base cases in this analysis. It is also assumed that the investment tax credit rate of 10% does not change over the study lifetime.

B. Depreciation

1. Expensing in Lieu of Cost Recovery. This provision in the Economic Recovery Tax Act of 1981 (ERTA) takes the place of bonus depreciation. The nonstructural components of the PV system that are used in a trade or business can be expensed. The structural components of the PV system are not eligible for this treatment. Amounts expensed are not eligible for tax credits or cost recovery. There is a $10,000 limit on the amount expensed. Expensing is not taken in the base case for this analysis.

2. Regular Cost Recovery (Depreciation) Accounting.

    a. The Accelerated Cost Recovery System (ACRS) contained in ERTA permits recovery of capital costs for most tangible depreciable property using accelerated methods of cost recovery over predetermined recovery periods generally unrelated to, but shorter than, useful lives. Cost recovery periods are the same for both new and used property. Under this system, the cost of eligible personal property is recovered over a 15-year, 10-year, 5-year, or 3-year period, depending on the type of property.

    b. The entire cost or other basis of eligible property is recovered under the new system, eliminating the salvage value limitation under present law.

    c. All non-structural components of the PV system are assumed in this analysis to be 5-year property.

3. Future Projections. For the base cases, it is assumed that the rules (rates, lifetimes, applicable property) concerning cost recovery and expensing do not change over the study time scope.

C. Revenues From the Sale of Electricity to the Local Utility

For all tax treatments except Bill Offset, it is assumed that the utility monitors the flow of electricity into and out of the PV home, and that the utility pays the homeowner for electricity sold to it. Thus, the revenues from the sale of electricity to the utility are easily identified and reported as taxable income by the homeowner. For the Bill Offset tax treatment, the meter is ratcheted backward in accordance with the sell-back price for each kWh returned to the utility. In this situation, the utility would presumably only pay the homeowner if the value of the electricity sold back exceeded the cost of the electricity purchased over the utility's normal accounting period.

D. Homeowner Specification

There are some severe restrictions on the typical homeowner in this analysis. His homeowner's after-tax discount rate is assumed to be constant over the study period and across homeowner income levels. His income and deductions are assumed to increase monotonically over time. The homeowner is assumed to maintain the same personal exemptions over the entire 30-year time horizon. Insofar as the only source of homeowner income is assumed to be salary and wages, this homeowner is assumed to realize no investment income (dividends or interest) or capital gains or losses over the study time horizon. With respect to the home in the base case, the homeowner is assumed either to remain in the home until 2016 (i.e., no early sale of the home) or to sell the home and capture the remaining value of the PV system in the selling price. Also, the loan is not retired before 2016. Part VIII specifies the assumptions concerning the nature of the income of the homeowner.

E. Treatment of the Revenues and Costs Associated with the PV Investments

1. Tax Treatments. This study assumes that the four base cases (Parallel, Business; Simultaneous, Business; Hobby; and Bill Offset) represent the major alternative tax treatments allowed by the IRS and the tax courts. In addition, the study assumes that all four would be recognized as legitimate by the IRS and the tax courts. It is, however, true that none has legal precedent. The Hobby or Bill Offset treatment will most likely be readily accepted by the IRS. The other two treatments, though, allow losses associated with the PV investment to offset income from other sources, and thus to serve as a tax shelter. The ability of a taxpayer to offset losses with other income hinges on the activity engaged in by the taxpayer being judged to be a business activity, possessing a profit motive and some type of economic activity. The Tax Guide for Small Business (Department of the Treasury, Publication 334, Revised November 1979) states that "an activity is presumed to be engaged in for profit if it produces a profit in any two out of five consecutive years" (Chapter 1, p. 3). However, the PV investments considered in this study do not, at the break-even costs, produce a profit in any of the first five years of activity, where profit is

defined as it is on Federal Form 1040, Schedule C. Hence, the IRS and/or the tax courts might disallow the Simultaneous, Business or Parallel, Business tax treatments. The disposition of this issue will depend on the subjective intention of the taxpayer as well as the objective facts and circumstances of each case.

2. Profitability Analysis. The recognition by the IRS that an activity is indeed a business enterprise engaged in for profit will ultimately be determined on a case-by-case basis. One definition of profit is provided by federal Form 1040, Schedule C (profit or loss from a business). Thus profit is defined as revenues minus the costs associated with conducting business such as interest, depreciation, etc. In this analysis revenues are realized from the sale of electricity to the utility. The cost elements are the trade or business fraction (defined as the ratio of the energy sold back to the total amount produced) of the O&M costs, the depreciation, the interest paid on the PV system, and the property taxes on the PV system. In determining profitability, the analysis assumes that the cost of grid electricity and the value of sell-back electricity continues to rise at a non-zero real rate after 1986. This contrasts with the break-even cost analysis, where a zero real increase in prices is assumed. Figures C-1 and C-2 show the annual profitability for the baseline residential PV system in Honolulu, Hawaii, for various assumptions concerning the PV system price and real escalation of electricity prices. Figure C-1 assumes a PV system price of $\$2.43/W_p$ ac and shows the annual profitability of the PV system for both 3% and 7% real escalation rates in energy prices from 1987 through 2016. Figure C-2 assumes a residential PV system price of $\$1.78/W_p$ ac. As can be seen, profitability is enhanced by increasing energy escalation rates and decreasing PV system prices. It can also be enhanced by decreasing the size of the loan the homeowner takes on the PV system (i.e., by increasing the down payment, since this reduces the annual interest payment). Another means of increasing the profitability is to expense the PV system cost rather than recovering it over time by means of the normal cost recovery mechanism (depreciation). The expensing provision of the ERTA applies only to 5-year investment class property and imposes a limit of $10,000 on the amount expensed. Expensing increases the profitability in the second, third, fourth, and fifth years of a project by causing the depreciation in these years (up to a maximum of $10,000) to be shifted to the first year (decreasing the profitability in that first year). However, expensing only helps the homeowner satisfy the IRS profitability guideline (of achieving a positive profit in two of the first five years of activity) if the trade or business is close to profitability in the second, third, fourth, or fifth years.

F. Capitalization of Sales Taxes

This analysis assumes that the sales tax associated with the purchase of the PV system is incorporated into the total PV system installed

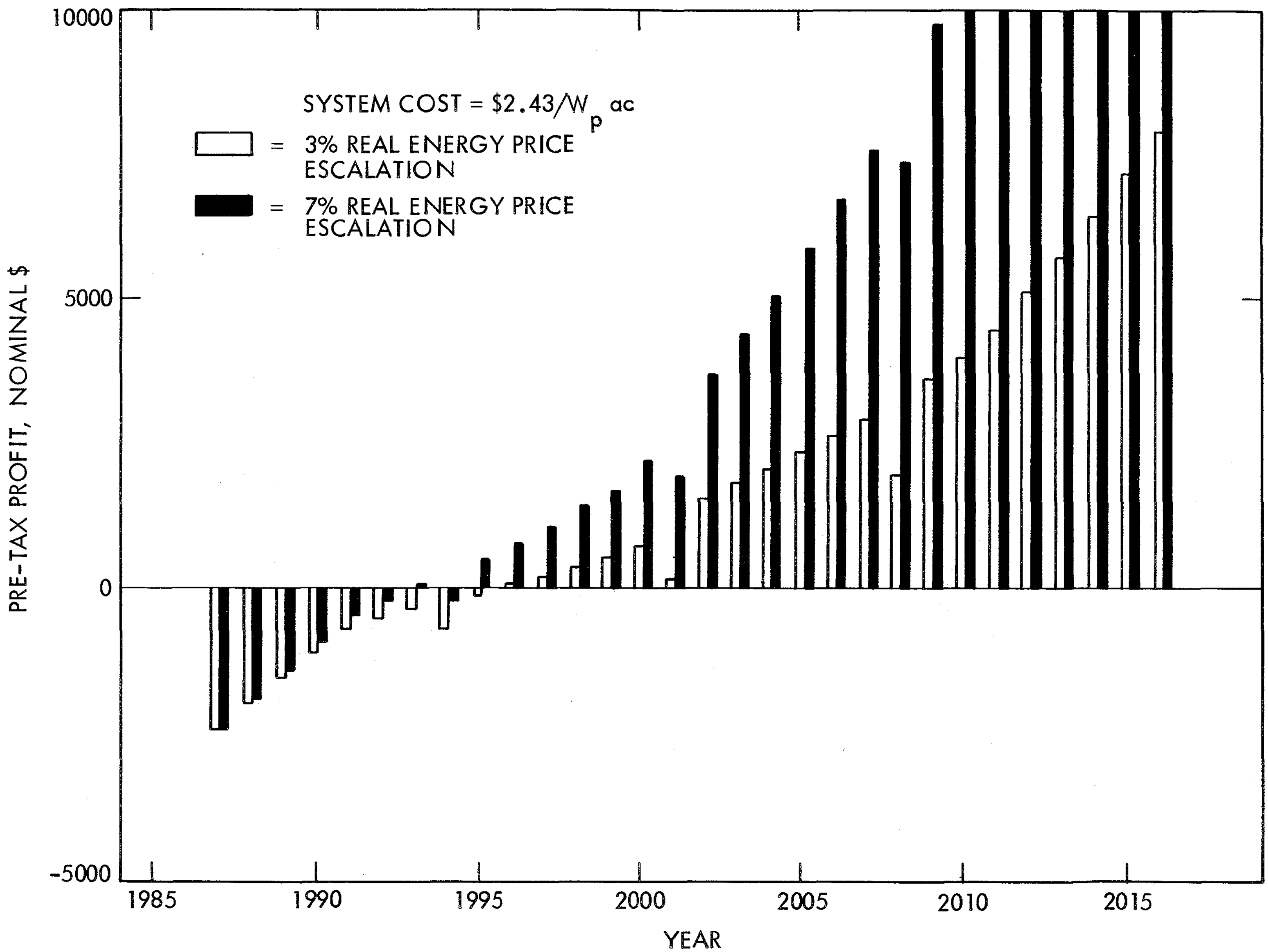

Figure C-1. Profitablility Analysis of $2.43/W_p$ ac Residential Photovoltaic Systems, 1980 $

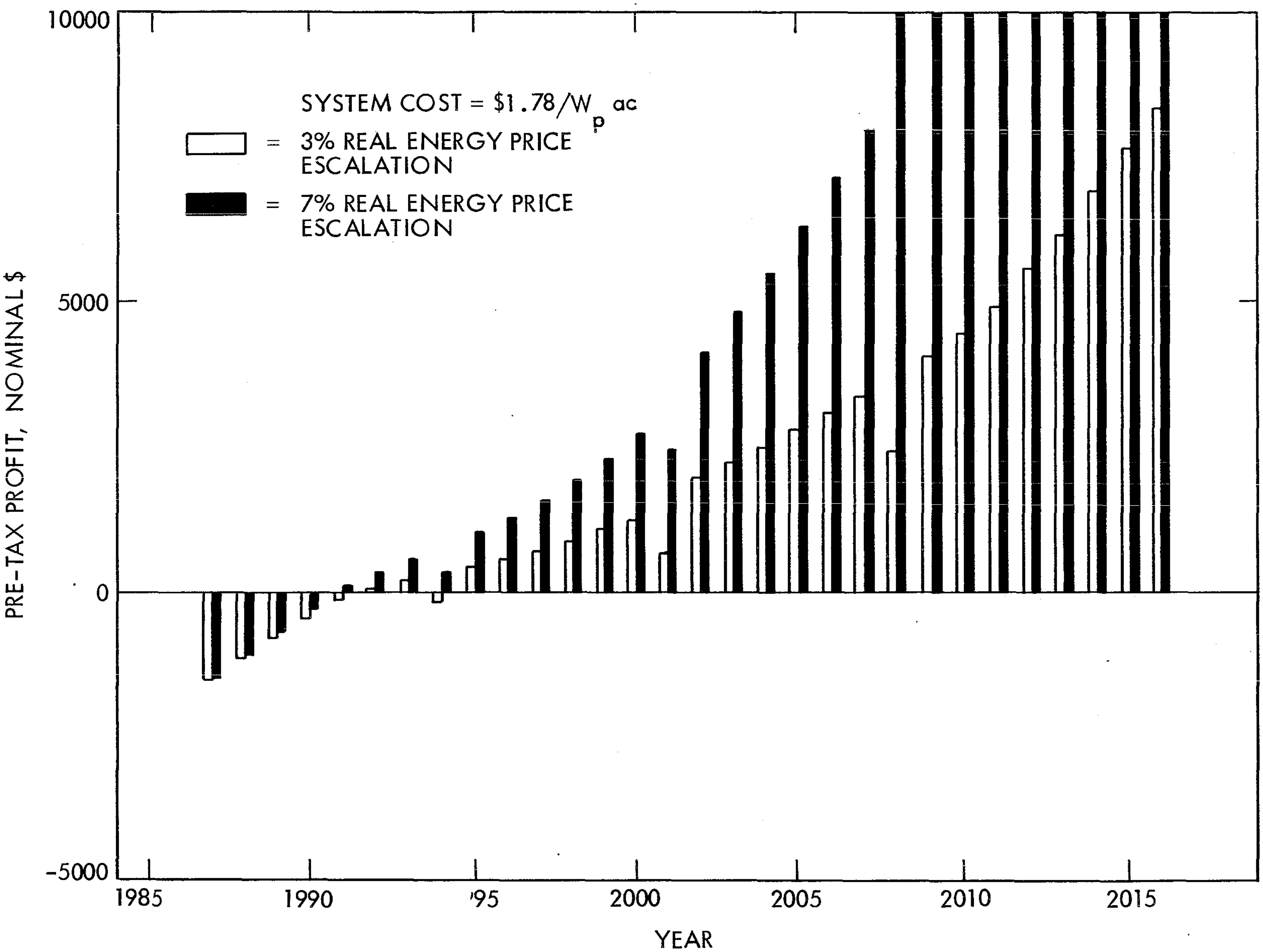

Figure C-2. Profitability Analysis of $1.78/$W_p$ ac Residential Photovoltaic Systems, 1980 $

price and is capitalized (and therefore recovered through deductions for depreciation.). An alternative assumption would be to recognize the sales tax paid on the PV system as a tax deduction (on Schedule A or C of federal Form 1040) in the year the system is purchased. This alternative assumption would require the builder to specify explicitly the sales tax component of the total installed system price. This alternative assumption is not made in this analysis, because (1) builders would not typically provide such detail to the PV system purchaser, and (2) accounting standards provide that all of the costs incurred in the acquisition and putting into service of a capital asset should be capitalized in a normal way, including interest, carrying charges, and sales taxes.

V. STUDY CAVEAT

In this study, the value of a PV investment to various types of homeowners in various United States locations has been quantified in terms of the break-even costs of the PV system. However, this is not a behavioral analysis. Thus, no implications can be drawn concerning how a potential investor might behave given these results. If, in fact, a homeowner could in 1986 obtain a PV system at or below the break-even cost, investment in a PV system would not necessarily occur.

VI. FIGURES OF MERIT

The PV system break-even cost is the figure of merit used in this analysis to quantify the value of the PV investment to the potential investor. A break-even cost is defined as the PV system price that makes investment in a PV system financially equivalent to purchase of all electricity needs from the local utility over the 30-year time horizon. APSEAM can also be used to determine the net present value to an investor of making one particular investment choice rather than another. The user inputs all cost and revenue items for each investment alternative and the model: (1) projects yearly pretax and after-tax cash flows for each alternative, (2) calculates the yearly differential after-tax cash flows that result from the choice of one alternative rather than the other, and (3) collapses this differential cash flow stream into a variety of figures of merit, one of which is the net present value.

APSEAM can also be used inversely. The value of any specified input variable that produces a desired end result can be determined through an internal iteration procedure. In this mode, the user specifies the desired end result (e.g., a net present value equal to zero) and the input variable whose value the user wants to calculate. A complication is introduced at this point, since the installed system cost consistent with a net present value equal to zero contains a variety of capital-related cost elements. For example, these cost elements may contain different lifetimes for ACRS deductions or different allowances for investment tax credits. Since there are at least three different cost elements in the PV system, the input variables for each of these cost elements must be simultaneously iterated when determining break-even costs for PV systems. Information on how these costs vary with respect to each other is required. In this break-even cost analysis, the costs of the various system elements are assumed to vary in proportion to the original cost estimates. These original cost elements are assumed to be:

Module cost, including installation (20 modules)	\$ 4750
Power conditioning unit, including installation	\$ 2193
Balance of system	\$ 3608
Total system cost for 4.34 kW_p ac system	\$10551

The process by which the model determines a break-even cost is as follows:

(1) The user inputs initial values for the various cost elements. This is assumed to define the cost relationship of the various cost elements. (For example, module costs are always a factor of 4750/2193 greater than power conditioning unit costs.)

(2) The user must also specify what the equivalent cost per kW_p is for these original cost elements. Let this value be termed initial unit capital cost (UCC_0). In this case, 10,551/4.34 = \$2.43/W_p ac = UCC_0.

(3) The model then determines the net present value for "new" values of the various cost elements. These "new" values are fixed multiples of the initial cost element values. The following equations are typical of those used:

New module cost = initial module cost x UCC_{BE}/UCC_0

New power-conditioning unit cost = initial power-conditioning unit cost x UCC_{BE}/UCC_0

New balance-of-system cost = initial balance-of-system cost x UCC_{BE}/UCC_0

In these equations, the multiplier is the ratio, UCC_{BE}/UCC_0. Thus, when UCC_{BE} is equal to UCC_0, then the "new" costs are the original costs. The model tries various values of UCC_{BE} until the net present value is equal to zero within some specified degree of precision. UCC_{BE} is then the break-even cost.

(4) Location-Specific Results

The base case assumes a homeowner with a \$40,000-per-year salary. He purchases a \$100,000 home. Assumptions concerning the deductions and personal exemptions at state and federal levels for the \$40,000-per-year homeowner are shown in Section VIII.

VII. PROPERTY TAXES: CALCULATIONAL DETAILS ON STATE-SPECIFIC RATES, ASSESSED VALUATION AS A PERCENTAGE OF MARKET VALUE, AND SOLAR EXEMPTIONS

The calculation of property taxes is based on the market value of the land and improvements, the assessed valuation relative to market value, and the property tax rate. For the \$40,000 homeowner purchasing a \$100,000 (unless otherwise noted) home, the land cost is assumed to be \$20,000. The value of the improvements, for the homeowner who does not purchase a PV system, is \$80,000; for the homeowner who does purchase a PV system in addition to the home, it is \$80,000 minus the amount of the roof credit. This amount is exclusive of the market value of the PV system itself. The market value of the land and improvements (including the PV system) is assumed to escalate yearly at 11% and 9%, respectively (except in California where these rates are legally constrained at 2%). Thus, for example, the property tax due in 1990 for the homeowner who does not purchase the PV system and who lives in a locale where the assessed value is 80% of market value and the property tax rate is 5%, is calculated as follows:

$$[(\$20{,}000)(1.11)^j + (\$80{,}000)(1.09)^j] \times (0.80) \times (0.05)$$

where $j = 1990 - 1980 + 1$

For the homeowner who purchases a PV system costing \$X (1980 \$), the property tax in 1990 is:

$$[(20{,}000)(1.11)^j + (80{,}000 + X - \text{roof credit})(1.09)^j] \times (0.8) \times (0.05)$$

The homeowner is assumed to pay his first property taxes in 1987 on the home purchased in 1986, at a rate based on the total assessed value of the home (i.e., there is no lag time assumed in the assessment of the newly completed home). The property tax payment in 1987 serves as a tax deduction on the homeowner's 1987 tax return. Table C-3 lists the property tax data used in this study.

Table C-3. Property-Tax Data

Location	Assessed Valuation as a Percentage of Market Valuation, %	Property Tax Rate, %*	Solar Exemption	Duration of Solar Exemption
Barstow	100	1.2375	No	NA
Boston	100	2.727	Yes	20 yrs
Alhambra	100	0.87	No	NA
Miami	100	2.812	Yes	10 yrs
Honolulu	60	1.523	Yes	end of 1981
Phoenix	25	11.55	Yes	end of 1989
Denver	9	8.47	No, but assessed valuation is 55.5% of normal assessed valuation	NA
Lincoln	100	2	Yes	end of 1986
Midland-Odessa	34	0.90	Yes	end of 1981

*Applied to assessed valuation.

VIII. HOMEOWNER INCOME AND TAX ASSUMPTIONS

A. Federal Income Assumptions

1. APSEAM makes the following three assumptions in the federal tax calculations:

   - The homeowner realizes no dividend income
   - The medical deductions claimed are those in excess of the 3% exclusion.
   - The homeowner has withheld in each tax year the precise amount of taxes owed. Hence, he realizes no tax refund or additional tax requirement in a subsequent year.

2. Tax Tables

Taxable Income, $	Tax, $	% on Excess
3,900	0	14
5,500	294	16
7,600	630	18
11,900	1,404	21
16,000	2,265	24
20,200	3,273	28
24,600	4,505	32
29,900	6,201	37
35,200	8,162	43
45,800	12,720	49
60,000	19,678	54
85,600	33,502	59
109,400	47,544	64
162,400	81,464	68
215,400	117,504	70

3. Other Federal Deductions[a]

Homeowner Income Level	Itemized Deductions	Personal Exemptions	Total
20	2000	4000	$2390
30	3000	4000	$3390
40	4000	4000	$4390
50	5000	4000	$5390

[a] These are the deductions, net of the $3400 exclusion for itemized deductions. In the analysis, the deductions and the exclusion for married couples ($3400--line 40 of Schedule A) are both assumed to escalate over time at the inflation rate after 1984. Before 1985, the deductions are assumed to escalate at the inflation rate but the $3400 exclusion is assumed to remain constant. In like manner, the $4000 personal exemption for the family is assumed to remain fixed until 1985 and to escalate annually thereafter at the inflation rate. Hence, in 1986, the "other" federal deductions (consisting of the taxpayer's excess itemized deductions and his personal exemptions) for the $40,000-per-year homeowner are:

$[4000 + 4000\,(1.09)^{-5} - 3400\,(1.09)^{-5}]\,(1.09)^{8}$ or $\$4390(1.09)^{8}$ in 1987 dollars.

B. State Income Assumptions

1. Massachusetts

a. Assumptions with respect to the nature of the homeowner's income are:

(1) The homeowner realizes only part B income (Part A income includes interest income, other than that from saving deposits in Massachusetts banks, dividend income, and net capital gains income).

(2) Both spouses have earned income exceeding $2000 and, hence, the personal exemption for the two adults totals $4000.

(3) The homeowner does not claim the special $600 exemption for children under 12; the couple does not deduct child care expenses.

b. Tax rate is 5% of income (excluding dividend, interest, and net capital gains income.)

c. In Massachusetts, deductions for $40,000-per-year homeowner include

Medical*	$1000
Personal exemptions:	
Married couple	$\$4000(1.09)^{-5} = \$2600$
Dependents (2, $700/dependent)	$\$1400(1.09)^{-5} = \$910$
Social Security tax	$1588
	$6098

For other homeowner income levels, the medical and social security tax deductions are:

Income

	$20,000	$30,000	$40,000	$50,000
Excess Medical, $	500	750	1000	1250
Social Security Tax, $	1330	1588	1588	1588

d. Economic Recovery Tax Act of 1981:

It is assumed that Massachusetts will not adopt the cost recovery or expensing provisions of ERTA.

2. Arizona

a. Nature of Homeowner Income:

(1) No dividend income.

(2) No interest income (from municipal bonds, U.S. savings bonds, treasury bills, etc.).

(3) The homeowner realizes no tax credits for the elderly, for child or dependent care expenses, for agricultural equipment, etc.

(4) The homeowner has no preference income or other special tax requirements.

---

*Massachusetts does not allow interest payments as a tax deduction. Of the total $4000 in "other" deductions at the federal level for the $40,000 homeowner, $1000 is assumed to be excess medical deductions and the rest to be non-PV and non-home-specific interest payments. These are assumed to escalate after 1980 at the inflation rate, as is the Social Security tax. The personal exemptions ($5400 total) are assumed to escalate only after 1984.

(5) The homeowner makes no early withdrawal of Arizona Retirement System contributions.

(6) The homeowner has no excess moving expenses, no partnership, estate, or trust income, no capital losses before Arizona residency, no preresidency installment sales, and no contributions to the Arizona State Retirement System.

b. Tax Tables:

Taxable Income, $	Tax, $	% on Excess
0	0	2
2,000	40	3
4,000	100	4
6,000	180	5
8,000	280	6
10,000	400	7
12,000	540	8

c. Deductions:

(1) Personal exemptions*:

Married Couples	$\$2844\ (1.09)^{-5} = 1848$
Dependents (2, \$854/dependent)	$\$1708\ (1.09)^{-5} = 1110$

(2) "Other" state deductions = 0
"Other" federal deductions = \$4000 (for \$40,000 homeowner)

(3) Additional medical deductions** = \$1400 (for \$40,000 homeowner)

(4) Total deductions \$8358 (for \$40,000 homeowner)

---

*Personal exemptions are assumed to remain fixed until 1985 and to escalate at the inflation rate thereafter.

**In Arizona there is no limitation on medical expenses; at the federal level, the medical deductions are reduced in two ways: (1) Medicine and drug expenses are reduced by 1% of adjusted gross income; (2) total medical deductions are reduced by 3% of adjusted gross income. A typical homeowner spends about 0.5% of his adjusted gross income on medicine and drugs. Thus, for a \$40,000 homeowner, the Arizona itemized deductions exceed the federal itemized deductions by \$1400 (3.5% of \$40,000). Additional medical deductions for other homeowner income levels are \$20,000, \$700; \$30,000, \$1050; and \$50,000, \$1750.

d. Depreciation and Expensing:

Arizona is assumed to adopt the ACRS and expensing aspects of ERTA. Structural components have a 15-year lifetime. Non-structural components have a 5-year lifetime.

N.B. In Arizona, federal taxes paid are state-tax-deductible.

3. California

a. Nature of Homeowner Income:

(1) Federal assumptions.

(2) The homeowner realizes no interest income.

(3) The homeowner is eligible only for energy-related tax credits. Thus, the homeowner realizes no tax credits for the elderly, for child or dependent care expenses, for agricultural equipment, etc.

(4) The homeowner has no preference income or other special tax requirements.

b. Tax Tables:

Taxable Income, $	Tax, $	% on Excess
0	0	1
5,260	52.60	2
9,220	131.80	3
13,180	250.60	4
17,160	409.80	5
21,120	607.80	6
25,080	845.40	7
29,020	1121.20	8
33,000	1439.60	9
36,940	1794.70	10
40,900	2190.20	11

c. Deductions and Tax Credits:

"Other" State Deductions =
"Other" Federal Deductions* = $4000

"Other" State Tax Credits:*
(2, $32/adult) +
(2, $10/child) = $ 84

---

*These are assumed to escalate at the inflation rate.

d. Economic Recovery Tax Act of 1981:

California is assumed to adopt cost-recovery and expensing provisions of ERTA.

4. Colorado

a. Nature of Homeowner Income:

(1) California assumptions.

(2) The homeowner realizes no pension or annuity income.

(3) The homeowner realizes no earned income credit.

b. Tax Tables:

Taxable Income, $	Tax, $	% on Excess
0	0	2.5
1,236	30.90	3.0
2,473	68.01	3.5
3,769	111.27	4.0
4,945	160.71	4.5
6,181	216.33	5.0
7,418	278.13	5.5
8,654	346.11	6.0
9,890	420.27	6.5
11,127	500.68	7.5
12,363	593.38	8.0

c. Deductions:

Personal exemptions:*
(4, \$1051/exemption) = \$4204 $(1.09)^{-5}$ = \$2732

"Other" State Deductions =
"Other" Federal Deductions = \$4000 (for \$40,000 homeowner)

Total Deductions = \$6732 (for \$40,000 homeowner)

d. Economic Recovery Tax Act of 1981:

Colorado is assumed to adopt the relevant provisions of ERTA.

N.B.: Federal taxes paid are a tax deduction in Colorado.
In Colorado there is a state investment tax credit of 2.5%.

---

*These are assumed indexed after 1984.

5. Hawaii

a. Tax Tables:

Taxable Income, $	Tax, $	% on Excess
0	0	2.25
1,000	22.50	3.25
2,000	55.00	4.5
3,000	100.00	5
4,000	150.00	6.5
6,000	280.00	7.5
10,000	580.00	8.5
20,000	1430.00	9.5
28,000	2190.00	10
40,000	3390.00	10.5
60,000	5490.00	11

b. Deductions:

Personal Exemptions: (4, $1000/exemption) $(1.09)^{-5}$ = $2600

"Other" State Deductions =
"Other" Federal Deductions = $4000

Total Deductions = $6600
(for $40,000 homeowner)

c. Economic Recovery Tax Act of 1981:

Hawaii is assumed to adopt the federal ACRS and expensing provisions.

6. Florida

No personal income tax.

7. Texas

No personal income tax

8. Nebraska

a. Nature of Homeowner Income:

(1) Federal assumptions.

(2) No interest income (e.g., from U.S. government bonds or other U.S. obligations).

(3) No income due to being an Indian on a Nebraska Indian reservation.

(4) No capital losses.

(5) No applicable total minimum taxes (from line 15 of Federal Form 4625) or alternative minimum taxes (from Federal Form 6251).

(6) No taxes paid to another state.

b. Tax:

Tax is 15% of federal taxes paid, before credits (line 35 of federal Form 1040).

c. Credits:

"Other" state tax credits* = $112.

IX. IMPACT OF MUTUAL DEDUCTIBILITY ON A TAXPAYER'S MARGINAL TAX RATE

An expression herein is derived for the effective marginal tax rate of a taxpayer who is a resident in a state that allows federal taxes paid as a deduction at the state level.

The federal government allows a taxpayer who itemizes his deductions to count state taxes paid as a deduction on the federal return. Hence, the total effective marginal tax rate for a taxpayer is:

$$R_{eff} = S + F (1 - S)$$

where S = the nominal state marginal tax rate, and

F = the nominal federal marginal tax rate.

The (1 - S) term reflects the deductibility of state taxes at the federal level.

However, this expression is not valid for those states (e.g., Arizona and Colorado) that allow the taxpayer who itemizes to count federal taxes paid as a deduction on the state return. In addition, this expression is valid only if the federal tax rate does not change when the deduction for state taxes paid is incorporated.

For those states where mutual deductibility is allowed, the expression for the final, effective marginal tax rate is:

$$R_{eff} = S' + F' \quad (1)$$

where $S' = S(1 - F')$ (2)

= the effective state marginal tax rate

$$F' = F(1 - S') \quad (3)$$

---

*These are assumed to escalate at the inflation rate.

(The term "effective" is used to signify the rate <u>after</u> the mutual deductibility has been incorporated.) Equations (2) and (3) must be solved simultaneously, for S' cannot be computed until F' is known, and F' cannot be computed until S' is known.

Substituting (2) into (3),

$$F' = F\,[1 - S\,(1 - F')]$$

$$F' = F - FS + FSF'$$

Rearranging,

$$F' = \frac{F(1 - S)}{1 - FS} \qquad (4)$$

Substituting (2) into (1),

$$R_{eff} = S' + F'$$

$$R_{eff} = S\,(1 - F') + F' \qquad (5)$$

Substituting (4) into (5),

$$R_{eff} = S\left[1 - \frac{F(1 - S)}{1 - FS}\right] + \frac{F(1 - S)}{1 - FS}$$

$$R_{eff} = \frac{S + F - 2\,FS}{1 - FS} \qquad (6)$$

Equation 6 is then the appropriate expression to use when not only are state taxes paid a deduction at the federal level, but also federal taxes paid are a deduction at the state level. Please note that this equation is applicable only if neither the state nor federal tax rates change when the appropriate deductions for taxes paid are included. (N.B.: because APSEAM considers the taxpayer's income in demanding the tax rate, the possible change in rate due to the incorporation of state and federal taxes as deductions precludes the use of this analytic solution in APSEAM. APSEAM, therefore, iteratively determines the appropriate state and federal taxes.)

The implication of Equation 6 is that mutual deductibility serves to lower the effective marginal tax rate of the taxpayer. For example, consider a taxpayer whose taxable income is such that his nominal state marginal tax rate is 10% and his nominal federal tax rate is 35%.

When federal taxes paid are not a deduction at the state level,

$$R_{eff} = F + S - FS$$

$$= 0.4150$$

When mutual deductibility is allowed,

$$R_{eff} = (S + F - 2FS)/(1 - FS)$$

$$= 0.3938$$

This represents a decrease of about 5% in the taxpayer's total effective marginal tax rate.

X. TYPICAL YEAR CASH-FLOW DETAILS

Cash flow detail for a typical year (1990 is chosen) for (1) the purchased-power option and (2) the Parallel, Business investment option, for a homeowner having $40,000-per-year income, living in Honolulu, is shown. In (3), the post-tax differential cash flow for 1990 is shown. (All dollar amounts in the cash flow tables are in 1990 dollars.) (N.B.: negative sign implies expenditure).

1. Purchased Power Option:

a. Pretax Cash Flow

Customer charge	- 111
Electricity charge	- 2,700
Increased interest & principal payments on home due to greater initial cost of home (i.e., loss of roof credit)	- 296
Pretax Cash Flow for Purchased-Power Option	- 3,107

b. State Tax Computation

"Other" state taxable income	107,057
"Other" state deductions	- 17,030
Interest payment on home	- 21,019
Property taxes	- 2,394
Taxable Income at State Level for Purchased Power Option	66,614
Gross State Taxes Due	5,638
State tax credits (for family members)	0
Net state taxes due	- 5,638

c. Federal Tax Computation

Other federal taxable income	107,057
Other federal deductions	11,328
Interest payment on home	21,019
Property taxes	2,394
State taxes paid	2,563
Taxable income at federal level	66,678
Taxes paid at federal level	- 13,045

d. After-Tax Cash Flow

Pretax cash flow	- 3,107
State taxes paid	- 5,658
Federal taxes paid	- 13,045
After-tax cash flow for purchased-power option exclusive of other income)	- 24,183

2. PV Investment Option

a. Pretax cash flow, $

Principal payment on PV system loan	- 81
Interest payment on PV system loan	- 3,066
O&M costs	- 12
Insurance	- 188
Customer charge for hooking to utility grid	- 111
Make-up electricity charge	- 1,729
Sell-back revenues	95
Pretax cash flow for PV option	- 4,237

b. State Tax Computation:

Other state taxable income	107,057
Sell-back revenues	951
Other state deductions	- 17,030
Interest payment on home	- 20,731
Business fraction	55%
Business portion of O&M costs	- 1,927
Property taxes	- 3,066
Taxable income	62,538
Gross state taxes due	- 5,231
State tax credits	0
Net state taxes due	- 5,231

3. Federal Tax Computation

Other federal taxable income	107,052
Sell-back revenues	951
Other federal deductions	- 11,328
Interest payment on home	- 20,731
Business fraction	55%
Business portion of O&M costs and of depreciation	- 1,927
Property taxes	- 2,705
State taxes paid	- 5,231
Taxable income, federal level	63,009
Taxes paid, federal level	11,834

d. After-Tax Cash Flow, PV Investment

Pretax cash flow	- 4,237
State taxes paid	- 5,231
Federal taxes paid	- 11,834
Property taxes	- 2,705
After-tax cash flow for PV investment option (exclusive of other income)	- 24,007

4. After-Tax Differential Cash Flow

(positive sign implies PV option is less expensive in that year)

After-tax cash flow for PV investment option	- 24007
After-tax cash flow for purchased power option	-(- 24183)
After-tax differential cash flow	+ 177

XI. RELEVANT PROVISIONS OF THE ECONOMIC RECOVERY TAX ACT OF 1981

A. Individual Income Tax Provisions

1. Reduction in Tax Rates. Present tax rates range from 14% to 70%. In 1984 and thereafter they will range from 11% to 50%. These new tax rates (same brackets as before) are incorporated in APSEAM for the residential analysis. (That analysis considers the cash flows experienced by the homeowner beginning in 1986; hence, the rates during the phase-in period are inconsequential.)

2. Indexing. Federal tax brackets will be indexed after 1985. The APSEAM user can currently specify if federal and state tax brackets are indexed or not, but cannot do so separately. Since some states will probably not follow the federal lead in this regard, APSEAM has been modified to allow the user to specify separately the indexing of state and federal brackets.

3. Reduction in the Alternative Minimum Tax: This provision does not affect the PV Residential Analysis, since it is assumed that the homeowner has no alternative minimum tax liability, because it is assumed that the homeowner has no capital-gains deductions or adjusted itemized deductions. (Adjusted itemized deductions are interest expenses and investment and nonbusiness expenses that exceed 60% of the taxpayer's adjusted gross income, net of taxes paid and medical deductions.)

4. Qualified Earned Income. ERTA allows a married couple filing a joint return a deduction from gross income of 10% (after 1982) of the lesser of $30,000 or the qualified earned income of the spouse with the lower qualified earned income. This provision does not affect this work; it has been assumed that the family has only one wage earner.

B. Business-Tax Incentive Provisions

1. <u>Depreciation</u>.

Depreciation of capital equipment is replaced by the Accelerated Cost Recovery System (ACRS). ACRS permits recovery of capital costs for most tangible depreciable property using accelerated methods of cost recovery over predetermined recovery periods generally unrelated to, but shorter than, useful lives under present law. Cost recovery periods are the same for both new and used property.

Under the new system, the cost of eligible personal property is recovered over a 15-year, 10-year, 5-year, or 3-year period, depending on the type of property. Most eligible personal property is in the 5-year class. Cars, light-duty trucks, research and experimentation equipment, and certain other short-lived property are in the 3-year class. Theme-park structures, railroad tank cars, and certain long-lived public-utility properties are in the 10-year class. Certain other long-lived public-utility properties have a 15-year recovery period. Eligible real property is placed in a separate 15-year real-property class. To provide flexibility, certain longer optional recovery periods are provided.

The entire cost or other basis of eligible property is recovered under the new system, eliminating the salvage value limitation under present law.

For example, for 5-year personal property, the year-by-year recovery percentages for property placed in service after December 31, 1985, are 20%, 32%, 24%, 16%, and 8%.

APSEAM allows the user to specify the investment class (3-year, 5-year, etc.) of each capital investment cost category for the purpose of calculation of the appropriate cost recovery (depreciation) deduction at the federal level. In addition, the depreciation basis is now not reduced by the salvage value of the property.

The bill also contains provisions concerning the recapture of these depreciation amounts, if the asset is sold before the end of the recovery period. These have no effect on this analysis, since the homeowner is assumed to retain the PV system well beyond the recovery period.

Bonus depreciation is not allowed for any property purchased after 1980.

2. <u>Expensing in Lieu of Cost Recovery</u>.

A taxpayer (other than a trust or estate) may elect to treat the cost of qualifying property as an expense that is not chargeable to any capital account. The costs for which the election is made will be allowed as a deduction for the taxable year in which the qualifying property is placed in service. For taxable years beginning in 1986 and later years, the dollar limitation is $10,000.

In general, the property for which an election may be made is personal property eligible to be treated as recovery property, if the property is acquired by purchase for use in a trade or business and is eligible for the investment credit. The trade or business limitation means that the election is not available for property held merely for the production of income (Sec. 212).

Although not explicitly specified in the bill, it is assumed that the cost basis for cost recovery is reduced by the amount expensed (analogous to the way in which the depreciation basis was reduced by bonus depreciation under the previous law).

Treatment of expensed property on disposition:

If any portion of the basis of property is expensed under the new provision, the amount expensed is treated as depreciation taken for purposes of the recapture rules of Section 1245. Thus, gain recognized on disposition of the property is treated as ordinary income to the extent of amounts expensed and depreciation taken.

Relationship to investment tax credit:

To the extent that the cost of property is expensed pursuant to this new provision, no investment tax credit or energy tax credit is allowed on the fraction of the cost expensed.

3. Investment Tax Credit:

The bill allows the 10% investment tax credit and the 15% energy credit for eligible 5-year and 10-year recovery property. For 3-year recovery property, only 60% of the investment qualifies for these credits. Because a taxpayer might have both 3-year and 5-year property, two investment and energy tax credit rates may apply. (5-year: 10% investment tax credit and 15% energy tax credit; 3-year: 6% investment tax credit and 9% energy tax credit).

Also, if the cost basis of both 3-year and 5-year property is reduced by expensing, the allocation of the total expensed amount (limited to $10,000) between the 3-year and the 5-year property must be specified (as noted above). This is necessary in order that the cost basis of each category of property can be determined before application to the investment and energy tax credit percentages appropriate for that category.

Special rules concerning the recapture of these credits have been provided but do not obtain if the taxpayer is assumed to retain the property for at least seven years. A final note: the bill provides that an investment credit will not be allowed with respect to amounts invested in qualifying property to the extent the invested amounts are not "at risk."

Assumptions within the PV residential base that this bill reemphasizes are:

(1) The family has only one wage earner.

(2) The family has no capital-gains income, dividend income, tax preference items in excess of prescribed amounts, or "adjusted itemized deductions."

(3) The homeowner is assumed to retain possession of the PV system and real property for a long enough time to preclude recapture concerns.

(4) The PV system has no salvage value.

(5) None of the PV system is 3-year-type property.

REFERENCES

C-1. Davis, R. and Kasper, J. V. V., "Overview of the Alternative Power Systems Economic Analysis Model," American Federation of Information Processing Societies (AFIPS) Conference Proceedings of the National Computer Conference, May 19-22, 1980, Anaheim, California, AFPIS Press, Arlington, Virginia, 1980.

C-2. Borden, C.S., Lifetime Cost and Performance Model for Distributed Photovoltaic Systems, JPL Internal Document No. 5220-12, August 1981.

End of Document