Photovoltaic Economics and Markets:

The Sacramento Municipal Utility District as a Case Study

September 1996

Prepared by

Howard Wenger and Tom Hoff
Pacific Energy Group
Walnut Creek, California

and

Jan Pepper
Enertron Consultants
Los Altos, California

Sponsored by

Sacramento Municipal Utility District
California Energy Commission
U.S. Department of Energy's PVCompact Program
(via North Carolina Solar Center)

SMUD Contract G253
CEC Contract 500-94-030

SMUD Project Manager
Donald E. Osborn

CEC Project Manager
Vincent Schwent

NCSC Project Manager
Bill Brooks

Acknowledgments

The authors extend special thanks to Don Osborn of the Sacramento Municipal Utility District for guiding and seeing this project through from start to finish, Mike DeAngelis of the California Energy Commission for initiating and supporting this work, and Vince Schwent of the California Energy Commission for making sure the wheels kept turning.

The constant assistance and support we received from Sacramento Municipal Utility District personnel is gratefully acknowledged. In particular we thank Don Osborn, Craig Jones, Janet Thatcher, and Dave Collier for their direction and constructive criticism. Many other individuals at SMUD contributed to this study, including, Yongxin Cai, Rosemary Davi, Iraj Deilami, Dennis Holcomb, Ed LaBranch, Jeff Miller, and Marino Monardi.

We also thank Bill Brooks of the North Carolina Solar Center, Jane Weissman of the Photovoltaics for Utilities organization, and the members of the California Photovoltaics for Utilities working group for their support. Thanks also to Pramod Kulkarni of the California Energy Commission and Krishna Shah of Western Area Power Administration.

The authors acknowledge with appreciation the financial support of the California Energy Commission, the Sacramento Municipal Utility District, and the U.S. Department of Energy's PVCompact Program (via the North Carolina Solar Center).

Executive Summary

This study focuses exclusively on grid-connected photovoltaic (PV) applications within the service area of the Sacramento Municipal Utility District (District) for utility- and customer-sited applications. The study was initiated by the California Photovoltaics for Utilities (PV4U) working group whose mission is to speed the commercial adoption of PV through the utility sector. The District agreed to provide the data and information needed to serve as a case study so that the new evaluation methods and results presented in this report could be of value to other utilities considering PV. The intent is not to validate the District's internal valuation methods or calculations, but to help the PV4U better understand the economics and markets for grid-connected PV systems. Major study findings follow.

UTILITY BENEFITS

Detailed analyses were conducted to determine the various benefits of utility-owned tracking and fixed PV systems at transmission and distribution voltage levels. The total, or "stacked", benefits are used by utilities to determine economic viability and select resource options.

Figure ES-1 presents the benefits of utility-owned PV systems at distribution voltage levels. Descriptions of these benefits are shown in Table ES-1. The present value of benefits, in 1996 dollars, range from $2,600/kW to $3,300/kW. On a levelized basis, these benefits are about $0.12/kWh, nominal ($0.08/kWh, real).

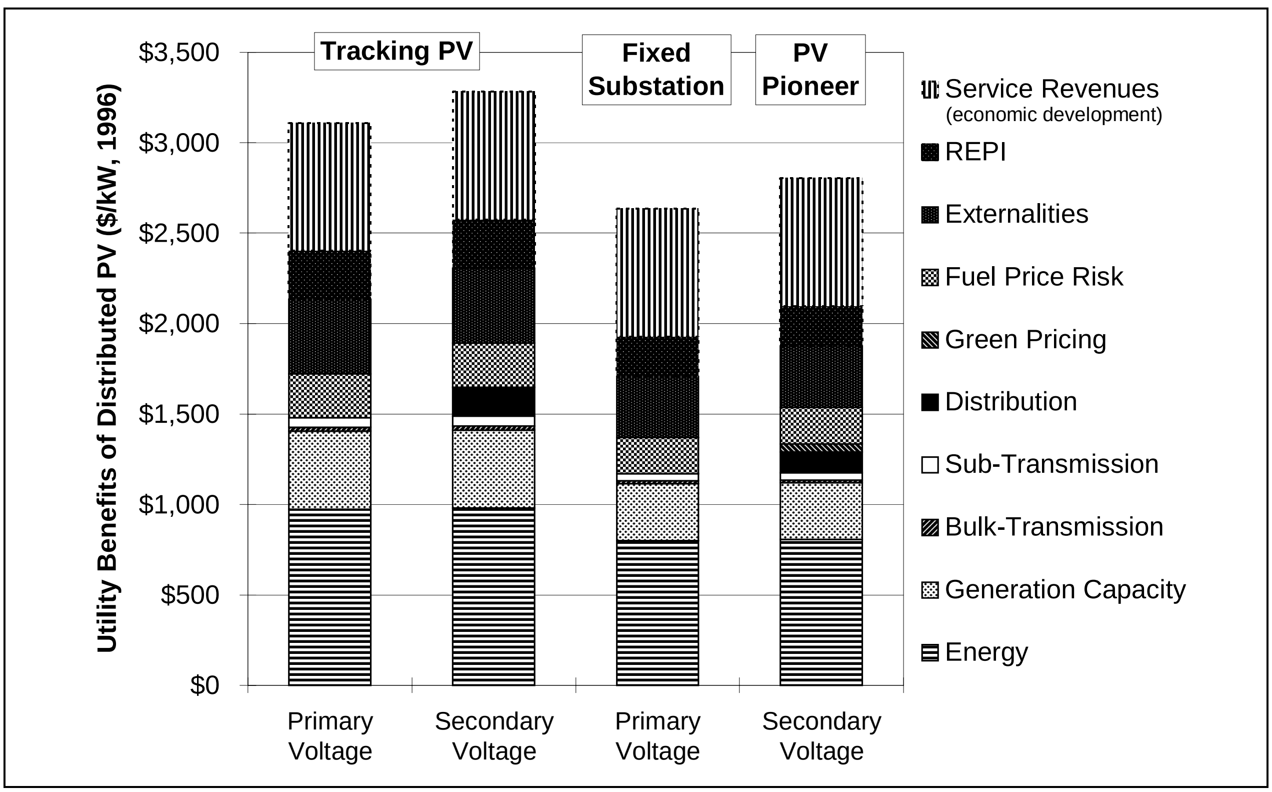


Figure ES-1. Utility benefits of tracking & fixed PV at distribution voltages.

Table ES-1. Utility Benefits Evaluated

Benefits	Description
Service Revenues (Economic Development)	Net service revenues from a new local PV manufacturing plant (result of economic development efforts)
REPI	Renewable Energy Production Incentive. Federal payments to public power agencies to encourage renewable energy investments
Externalities	Value of reduced fossil emissions
Fuel Price Risk Mitigation	Value of reducing risk from uncertain gas price projections
Green Pricing	Voluntary monthly contributions from PV Pioneers
Losses	Electric loss reduction (accounted for in each benefit)
Distribution	Distribution capacity investment deferral
Sub-Transmission	Sub-Transmission capacity investment deferral
Bulk-Transmission	Transmission capacity investment deferral
Capacity	Avoided marginal cost of systemwide generation capacity
Energy	Avoided marginal cost of systemwide energy production

Figure ES-2 presents the benefits of a utility-owned tracking PV system by percentage. Significant "non-traditional" benefits have been determined from increased service revenues, externalities including fuel price risk mitigation, and REPI payments. Without these additional benefits, the total value of PV would be about $1,650/kW. The added non-traditional benefits double the traditional energy, capacity, and T&D benefits, bringing the total to about $3,300/kW.

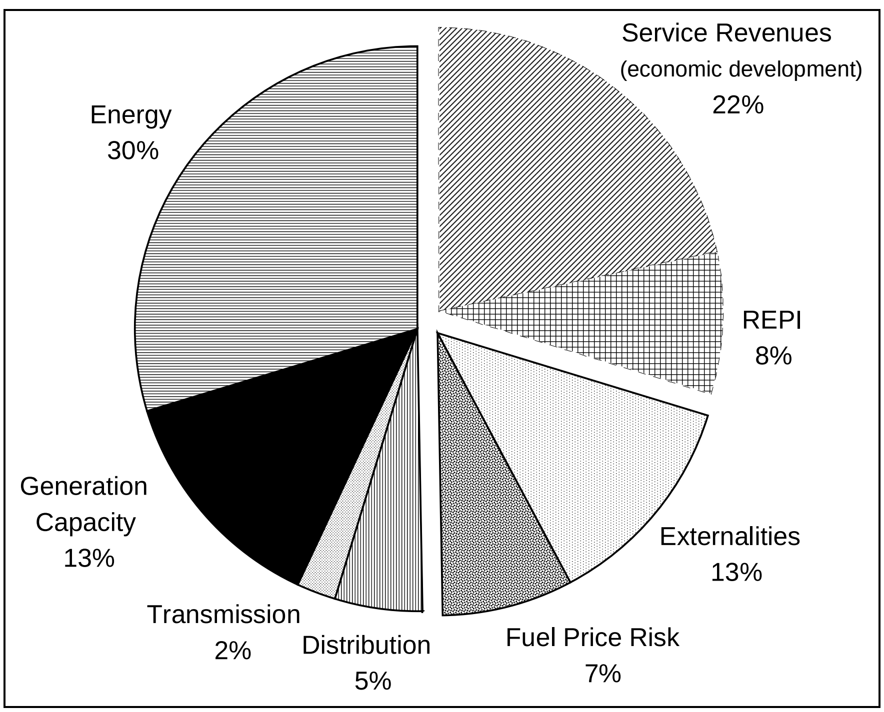


Figure ES-2. Utility benefits of a tracking PV system (% of total benefits).

The energy, capacity, externality, and T&D benefits were calculated using data from the District's 1995 Marginal Cost Study. These benefits must be revisited once the District completes a new study that considers electric industry restructuring impacts on marginal costs.

Service Revenues and REPI payments are split off in Figure ES-2 because of their uncertainty. In this study, it is assumed that the District's presently active 50-MW RFP for renewable resources will result in a new PV manufacturing facility in the Sacramento area. The increased net revenue from electricity sales to this new PV facility is the "Service Revenues" benefit. Therefore, the Service Revenues benefit is shown with a dotted line since it is dependent on the outcome of the RFP process.

REPI payments are provided by the U.S. Department of Energy for solar, wind, and biomass resources owned by public power agencies such as the District. The longevity of REPI is somewhat tenuous as it must survive the rigors of the annual appropriations process. For this reason, although the District has received REPI payments in the past, the REPI benefit is also depicted with a dotted line because of future uncertainty.

UTILITY BENEFITS CALCULATIONS WITH QUICKSCREEN SOFTWARE

A computer software package called QuickScreen, previously developed by Pacific Energy Group with funding provided by the U.S. Department of Energy, was used in this study to re-calculate the utility benefits of distributed PV. QuickScreen is a Windows point-and-click package that is intended to provide a simple-to-use tool that requires minimal effort to evaluate specific distributed PV applications. Extensive documentation and on-line help are available within the QuickScreen software. Using the District as a case study provided an opportunity to further validate QuickScreen and to demonstrate how other utilities can easily investigate the viability of distributed PV applications.

Figure ES-3 shows the benefits calculations from four of the detailed analyses and compares them with the QuickScreen (QS) results. The overall QuickScreen results are within 5% of the detailed analysis results. Standard QuickScreen charts and data sheets are provided in the Appendices.

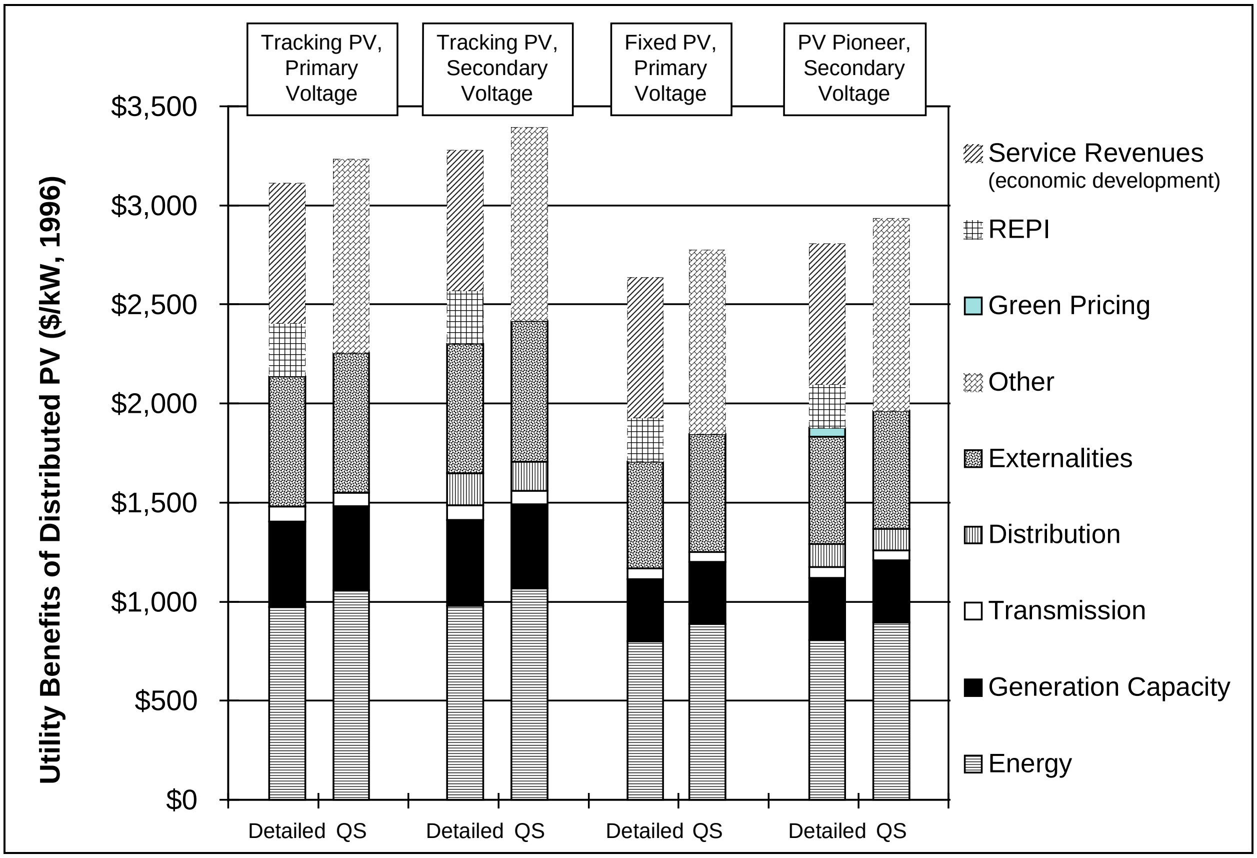


Figure ES-3. Benefits comparison: Detailed vs. QuickScreen analysis.

PV SYSTEM PERFORMANCE

Performance simulations and load analyses were conducted to determine the expected performance of PV systems on an average-year basis. Table ES-2 summarizes these results. Tracking provides energy and capacity advantages over fixed arrays of about 20% and 40%, respectively.

Table ES-2. Expected Average Annual Performance of PV Systems

	Single-Axis Tracking (Hedge Substation)	**Fixed Rooftop (Residential PV Pioneer)**
Capacity Factor	24.7%	20.3%
Energy Output	2,160 kWh/kW-year	1,780 kWh/kW-year
Capacity Credit	73.0%	53.2%

NET METERING

As of January 1, 1996 a new law requires all California utilities to develop a tariff to provide net metering of residential PV systems up to 10 kW in size. Two investor-owned utilities initially responded to the law by requesting Public Utilities Commission approval of net metering tariffs that included customer standby charges. Recently both of these utilities eliminated these standby charges because it was ruled that the charges would defeat the intent of the law which is to "encourage private investment in renewable energy resources, stimulate in-state economic growth, enhance the continued diversification of California's energy resource mix, and reduce utility interconnection and administrative costs".[1]

The District plans to address net metering in its 1996 rate action. To evaluate the impact of net metering in this project, a range of PV system sizes from 0.5-kW to 4-kW was investigated. The effect of a monthly standby charge of about $5/kW-month was also analyzed.

The analysis shows that a 0.5-kW system yields bill savings of $8/month and a 4-kW system yields $50/month in bill savings, translating into a reduction in the customer's total annual utility bill of 15% and 75%. Figure ES-4 shows that the larger the system size, the greater the impact of net metering compared to conventional dual metered systems. A customer with a 2-kW PV system would have an 18% increase in annual bill savings if their system were net metered rather than dual metered, and a 4-kW PV system would yield a 45% increase in annual bill savings. The addition of a standby charge would offset any savings gained by net metering.

The impact of the California net metering law on the District was also evaluated. The law makes net metering available for each utility on a first-come first-served basis until the total PV capacity reaches 0.1% of the utility's 1996 peak demand. For the District, this translates to about 2.6 MW of customer-owned PV. The basecase results show that the law will have no practical effect on the District's rates. While not a standard utility test, the impact on rates can be seen by the results in the worst case scenario that shows that rates would have to be increased by about 0.0009% or nine thousandths of 1 percent to cover the effect of net metering.

[1] California Public Utilities Code § 2827.

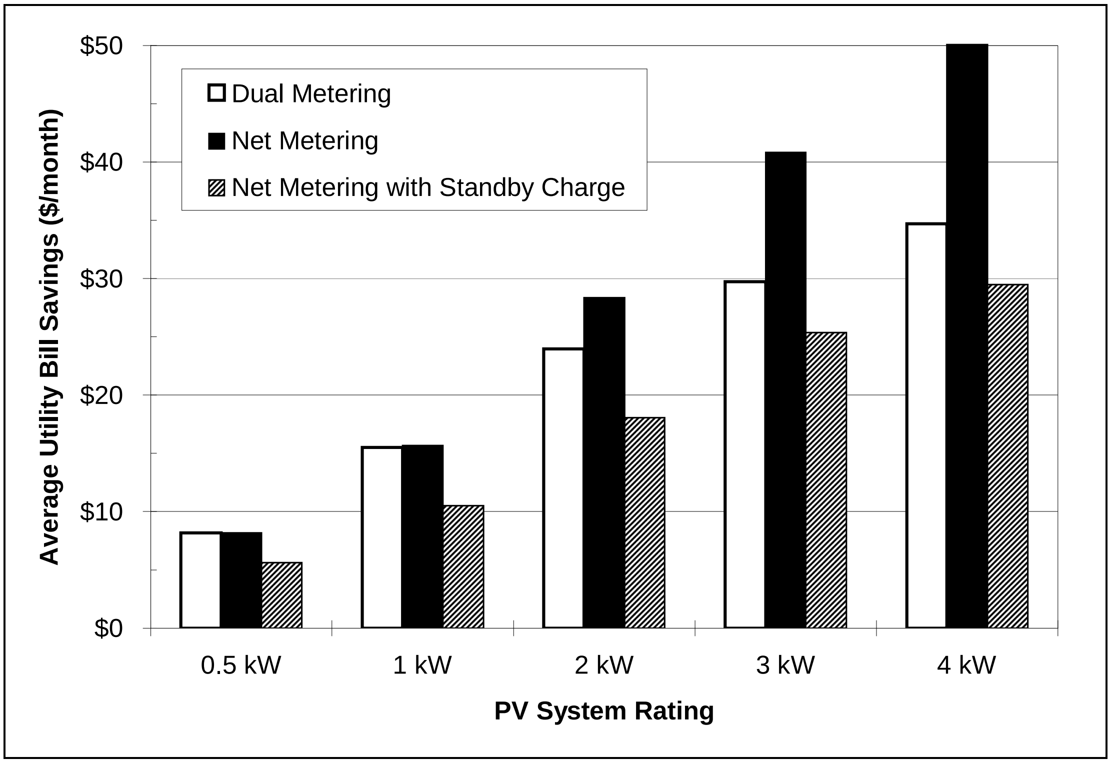


Figure ES-4. Utility bill savings vs. metering scheme vs. PV size.

RESIDENTIAL ROOFTOP PV SYSTEMS: PV PIONEERS AND CUSTOMER-OWNED

A number of different data sources were used to estimate the upper bound "market potential" for residential rooftop PV systems in the District's service area. These sources include aerial photographs, 1990 census data, National Roofing Contractors Association data, Internal Revenue Service and California Franchise Tax Board statistics, and the District's experience installing PV Pioneer systems. The data provided District-specific statistics on roofing material, roof orientation, roof area, shading factors, home ownership, and income and tax rate distribution.

Based on these statistics, it was determined that the upper bound market potential for residential PV Pioneer systems in the District's service area is about 400 MW on 100,000 homes. Over 50% of this available capacity is located in two areas, Carmichael/Citrus Heights and South Natomas/Elverta. On average, across the entire service area, one in five homes meet the roofing material, orientation, area, and shading criteria required to locate a viable rooftop PV system.

The upper bound market potential was also investigated for residential customer-owned PV systems. The upper bound capacity is approximately 220 MW on about 50,000 homes with an economic break-even range of $2,500/kW to $3,800/kW depending on PV system size. A $4,000/kW PV system that is financed with a low (3%) interest 100% debt loan would yield a payback of 5 years.

COMMERCIALIZATION STRATEGIES

One of the objectives of this study is to provide insight on the viability and timing of commercialization paths for grid-connected photovoltaics. A few possible strategies are discussed.

Sustained Orderly Development

The District has embarked on a path of continued PV procurements with the expectation that PV prices will decline as long as the District, with other utilities and energy providers, provide a sustained commitment to purchase PV systems in sufficient quantities. This commercialization strategy has been referred to as Sustained Orderly Development (SOD).

Figure ES-5 shows PV system cost curves based on historical (actual) and projected costs.[2] PV system prices have declined dramatically since 1984, at a rate of about 5.5%/year, representing a real decline in PV prices of 9%/year in the absence of inflation. Lines A & B depict this "business as usual" trend. Line C is the projected PV system cost curve that the District expects from the SOD process (costs during 1997-2002 are based on actual bids received by the District).

The range of utility benefits calculated using the District as a case study is overlaid on the cost curves to determine the timing of cost-effectiveness. This benefit range, from $1,700/kW-$3,500/kW, encompasses the value of tracking and fixed PV systems at different interconnection locations, time frames of deployment, and benefits categories. The following observations are made regarding Figure ES-5:

- PV system prices are presently twice as high as they need to be to achieve cost-effectiveness without subsidies;
- PV will be cost-effective for SMUD systems in the 2000-2004 time frame, assuming that PV costs follow the SOD trajectory and the utility benefits remain fairly constant;
- The SOD strategy could accelerate PV commercialization for SMUD-owned systems by about 6 years; and
- Under the "business as usual" scenario, to reach a PV system price of $3,000/kWac in 2006 requires a cumulative worldwide sales volume of about 3,200 MW, or about seven times the cumulative sales to date. In contrast, the SOD cost curve results in a $3,000/kWac PV system price around the year 2000.[3]

---

[2] PV system costs in Figure ES-5 include sales tax on hardware and District added costs, such as interconnection, District labor, administration, overhead, AFUDC and operations and maintenance.

[3] Sales tax and District added costs are expected to add about $330/kW (1996$) to the system price for a total PV system cost to the District of $3,250/kW in the year 2000.

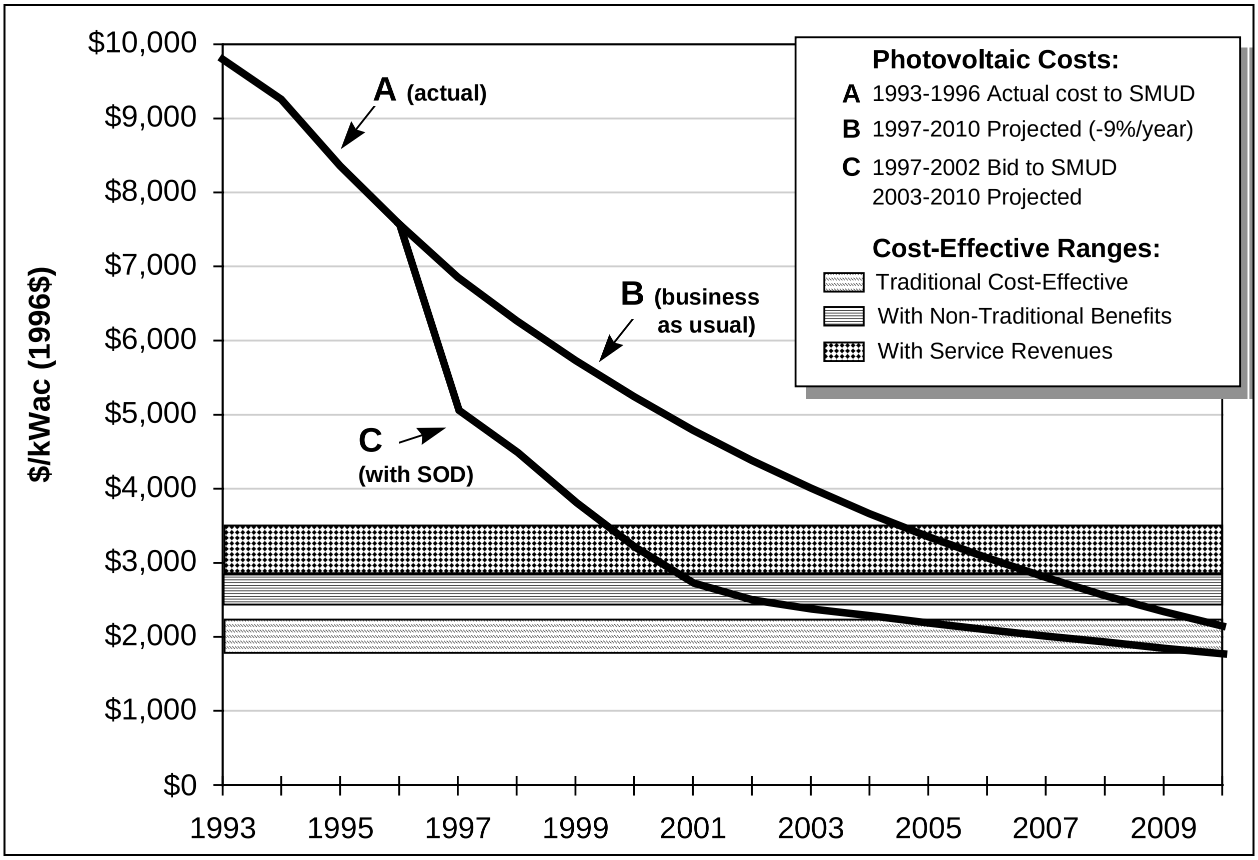


Figure ES-5. PV cost trajectories and cost-effectiveness ranges (real 1996$).[4]

Multi-MegaWatt IPP Strategy

Amoco/Enron Solar Power Development is seeking to redefine the market by greatly accelerating manufacturing investment and volume, coupled with aggressive pricing that is far below the Sustained Orderly Development PV price projections. Amoco/Enron has proposed to build multi-MW power plants at a cost of $1,750/kW with a reported power purchase contract beginning at $0.05/kWh-$0.06/kWh in the first year and escalating thereafter, roughly at inflation.

Cost-effective distributed PV plants can be installed much earlier than projected if a company like Amoco/Enron is successful. Their success would alter the face of the PV and energy industries. The Amoco/Enron joint venture, however, has yet to install a single kW of PV and many years and millions of dollars will pass before it will be known if they can deliver on their large-scale IPP strategy in a profitable and sustainable way. As such, Amoco/Enron's progress will continue to be closely watched by the energy industry and financial markets.

---

[4] Photovoltaic Costs: "A 1993-1995 Actual, 1996 Bid" based on District PV system costs; "B 1997-2010 Projected" based on historical annual reduction of 9% per year; "C 1997-2010 Projected" based on the District's cost reduction estimates of 17% annual average to the year 2000 and 5% annual average from 2000 to 2010. Cost-Effective Ranges: "Traditional Cost Effective" based on the District's Renewable Marginal Costs; "With Non-Traditional Benefits" include green pricing, distribution capacity benefits, and REPI payments; "With Service Revenues" accounts for the projected revenue increase from locating a PV manufacturer in the District's service area.

Niche Market Strategy

This strategy centers around the identification and exploitation of niche markets that are profitable today, but are not likely in very large quantities. The approach directly engages utility customers, the end-user, to take advantage of incentives that are available only to customers or third parties who directly own PV systems. These incentives include compensation for power at retail electric rates, willingness to pay premiums for clean power and to be an innovator, tax credits, and financing options.

The niche market strategy dictates that any one incentive in isolation is not enough to make a difference to enable PV system sales, but in aggregate may be enough to form a significant niche market. The best niche market candidates, for example, are locations with a good solar resource, high utility rates, net metering, tax credits, and progressive state government, regulatory, and utility support.

Recent research shows that PV break-even costs exceeding $7,000/kW are available in certain niche markets such as new residential developments in Hawaii. This is due to an excellent solar resource, high utility rates, and favorable state solar tax credits. Some industry participants believe that exploitation of these types of niche markets is a promising strategy for speeding the commercialization of grid-connected photovoltaics.

CONTENTS

FIGURES

TABLES

1. Introduction

This study was initiated by the California Photovoltaics for Utilities (PV4U) working group whose mission is to speed the commercial adoption of photovoltaics (PV) through the utility sector (California PV4U 1993). The study is sponsored by the California Energy Commission, Sacramento Municipal Utility District (District), and the Department of Energy through the North Carolina Solar Center and PVCompact, a national PV education and commercialization program.

This study focuses exclusively on grid-connected PV applications within the District's service area for utility- and customer-sited applications. The intent is not to validate the District's internal valuation methods or calculations, but to help the PV4U better understand the economics and markets for grid-connected PV systems in order to improve and solidify commercialization strategies.

1.1 Study Objectives

This study has the following specific objectives:

- Quantify the traditional and non-traditional benefits of PV for utility-owned systems;
- Determine the economics of PV under different ownership arrangements;
- Provide realistic performance and rating estimates for tracking and fixed systems;
- Examine the impacts of policy decisions regarding metering and rate tariffs;
- Construct market demand curves for utility and customer-owned applications;
- Further validate the QuickScreen software package; and
- Provide insight on technology commercialization paths

1.2 Approach

There are many approaches to consider when evaluating the economic viability of and commercialization strategies for grid-connected PV. These approaches are enabled, to a large extent, by the technology's modularity and environmental compatibility. Grid-connected PV can be deployed in a host of applications, from small customer rooftop systems that offset a portion of electricity consumption to large-scale power plants that provide utilities with systemwide peaking capacity. Layered on this range of applications is a commensurate number of ownership and financial arrangements, including direct utility ownership, third-party ownership with a utility power purchase agreement, direct customer purchase, and leasing arrangements with options to purchase. The District agreed to provide the data and information needed to serve as a case study so that the new evaluation methods and results presented in this report could be of value to other utilities considering PV.

Table 1-1 presents a matrix of the main elements considered in this study. Shaded cells indicate that the element directly impacts one or more of the following perspectives: utility, customer, and third-party. Four economic evaluation scenarios form the foundation of the study. Based on these scenarios, a number of elements are considered including T&D and fuel diversity benefits that directly affect the District for utility-owned systems and bill savings and net metering impacts that directly affect customers who purchase PV systems. In addition, PV rating and performance are examined and, finally, commercialization strategies are discussed.

Table 1-1. Main Study Elements

Main Study Elements	**Shaded Cells = Direct Impact**		
	Utility	**Customer**	**Third-Party**
ECONOMIC EVALUATION SCENARIOS			
Direct PV system purchase by utility			
Power purchase agreement (via levelized benefits)			
Direct PV system purchase by customer			
Utility or third-party lease to customer with option to buy			
ECONOMIC EVALUATION ELEMENTS			
Traditional energy and capacity benefits			
Transmission and distribution deferral benefits			
Economic development benefits (increased service revenues)			
Fuel price risk mitigation benefits			
Environmental benefits			
Green pricing (PV Pioneer)			
Tax benefits from financing			
Bill savings and net metering impacts			
PV PERFORMANCE			
Rating PV systems			
Performance estimation			
COMMERCIALIZATION ISSUES			
PV system price over time			
Utility benefits over time			
Market demand curves			
Strategies to speed commercialization			

2. Background on the Sacramento Municipal Utility District

2.1 THE DISTRICT'S PHOTOVOLTAIC PROGRAM

The District has purchased and installed over 340 turnkey PV systems with a combined capacity of about 4.3 MWac (4.9 MWac, EPF[5]). Table 2-1 presents the SMUD PV grid-connected PV system portfolio by system type and system capacity rating (Osborn and Collier, 1995). SMUD's PV system portfolio is broken down into four different applications: Residential, commercial, parking lot, and substation. Residential, commercial, and parking lot systems are generally located on customer premises whereas substation systems are typically located on utility property adjacent to distribution substations. One-third of the total rated capacity is located on customer premises and two-thirds at substation locations. This mix is weighted by the 2 MW of substation systems installed at Rancho Seco in the mid-1980s, however, and SMUD has since focused its program on customer-sited installations.

Figure 2-1 demonstrates the District's commitment to sustained PV purchases, ramping up to the year 2002. The District plans to procure approximately 12 MW of PV during 1996-2002, bringing the total to about 16 MW (17.5 MW, EPF) of District-owned PV systems by the year 2002 (SMUD, 1996c and 1996d).[6] Figure 2-2 presents a very preliminary breakdown of the 16 MW by PV system application type. Decisions as to where these systems will be installed have not yet been finalized. About 30% to 35% (5 to 6 MW) of these systems may be "PV Pioneers" whereby customers, mostly residential, volunteer to pay a premium on their monthly utility bill and have the District install PV on their rooftops. Another 35% (6 MW) may be grid-support systems adjacent to distribution substations. About 20% (3 MW) may be installed in parking lots where the PV can provide the dual function of electricity production and covered parking. The remaining 1 MW or so will be assigned to emerging applications, such as architectural building-integrated treatments.

Fixed rooftop and tracking substation flat-plate PV system configurations are the focus of this study since most of the approximately 4.3 MW of PV system capacity purchased and owned by the District since 1984 fits in these two categories. It is anticipated that the majority of the anticipated additional 12 MW of PV systems procured over the next 8 years will have a similar system design mix.

---

5 The EPF, or Energy Potential Factor (introduced by SMUD and adopted by the Utility PhotoVoltaic Group) is an alternate rating method that accounts for the improved performance of tracking systems. The purpose of the EPF is to allow direct comparison between fixed and tracking PV system prices by "crediting" the extra energy delivered by tracking PV. A north-south single-axis tracker located in Sacramento, CA has an EPF of 1.23. See the PV System Ratings and Performance section for additional comments on the EPF.

6 It is possible that the District will contract for an additional 20 MW of PV through a power purchase agreement (SMUD, 1996d). The District has issued an open solicitation calling for up to 10 MW per year of additional renewable energy capacity. Other eligible competing renewable resources include landfill gas, biomass, wind, solar, and sustainable geothermal reservoirs.

Table 2-1. SMUD PV System Portfolio, Procured 1984-1995

	Year	Number of Systems	Rating (kWac)	Rating, EPF (kWac)	Type	Supplier	% of Total kW Capacity
Residential							
PV Demo	1993	n/a	10	10	Fixed, rooftop	n/a	
PV Pioneers	1993	108 @ 3-4 kW	400	400	Fixed, rooftop	Siemens	
PV Pioneers	1994	109 @ 3-4 kW	400	400	Fixed, rooftop	Solec	
PV Pioneers	1995	25 @ 3-4 kW	87	87	Fixed, rooftop	RMI/ Solarex	
PV Pioneers	1995	80 @ 3-4 kW	329	329	Fixed, rooftop	Placer/ Solarex	
Residential Total		322	1,226	1,226			29%
Commercial							
Warehouse	1993	1	30	37	Linear concentrator	PV International	
WAPA Demo	1994	1	3	3	Flatplate, rooftop, building-integrated	PowerLight	
PV Pioneers Commercial	1994	8 @ 18-30 kW	144	144	Fixed flatplate, rooftop	Solec	
Commercial Total		13	177	184			4%
Parking Lot							
SMUD PVEV	1992	1	11	11	Seasonally-adjustable station	ARCO	
PVEV Airport	1995	1	8	8	Tracking	ARCO	
Metro Airport Carport	1995	1	128	158	Tracking flatplate, covered parking	Utility Power Group/Siemens	
Parking Lot Total		3	147	177			3%
Substation							
Rancho Seco PV1	1984	1	1,000	1,230	Tracking flatplate	ARCO	
Rancho Seco PV1	1986	1	1,000	1,230	Tracking flatplate	ARCO/ Solarex/Mobil	
Hedge PV1	1993	1	207	255	Tracking flatplate	Utility Power Group/Siemens	
Hedge PV2	1994	1	108	108	Fixed flatplate	Advanced PV Systems, Inc.	
Hedge PV3	1994	1	102	102	Fixed flatplate	RMI/ Solarex	
Hedge PV4	1995	1	107	132	Tracking flatplate	Utility Power Group/Siemens	
Rancho Seco PV3	1995	1	214	263	Tracking flatplate	Utility Power Group/Siemens	
Substation Total		7	2,738	3,320			64%
TOTAL		**342**	**4,288**	**4,907**			**100%**

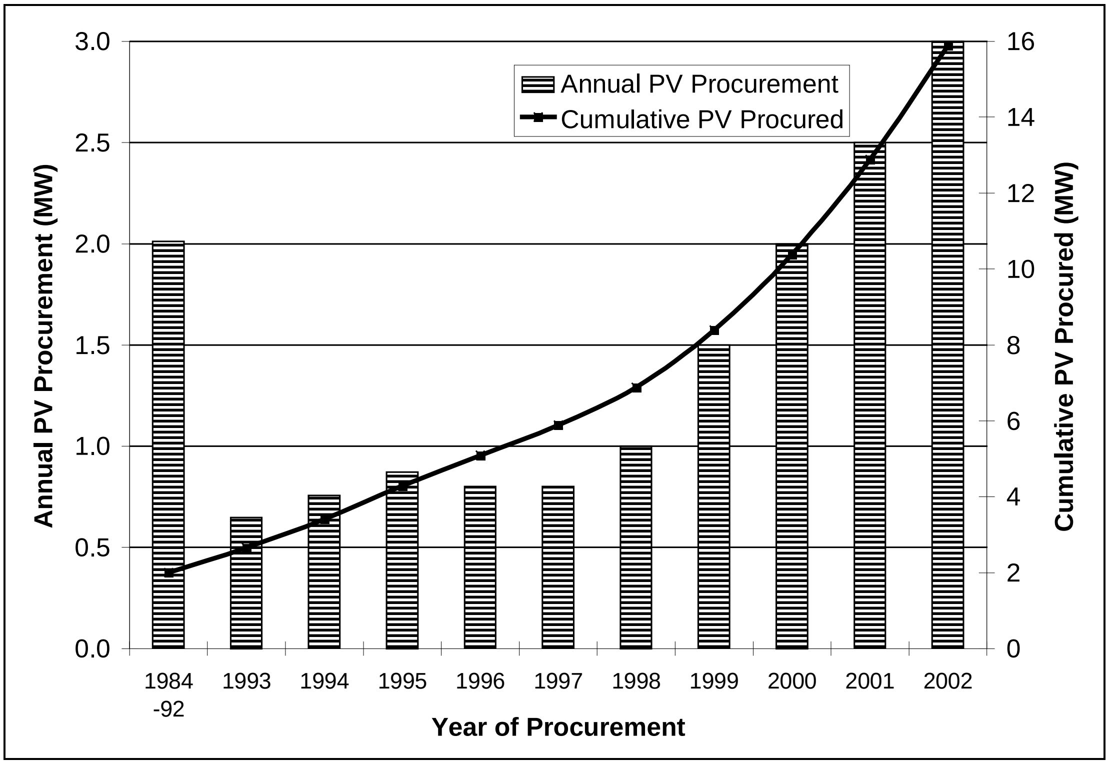


Figure 2-1. SMUD PV Program: Annual and cumulative procurements (SMUD, 1996d).

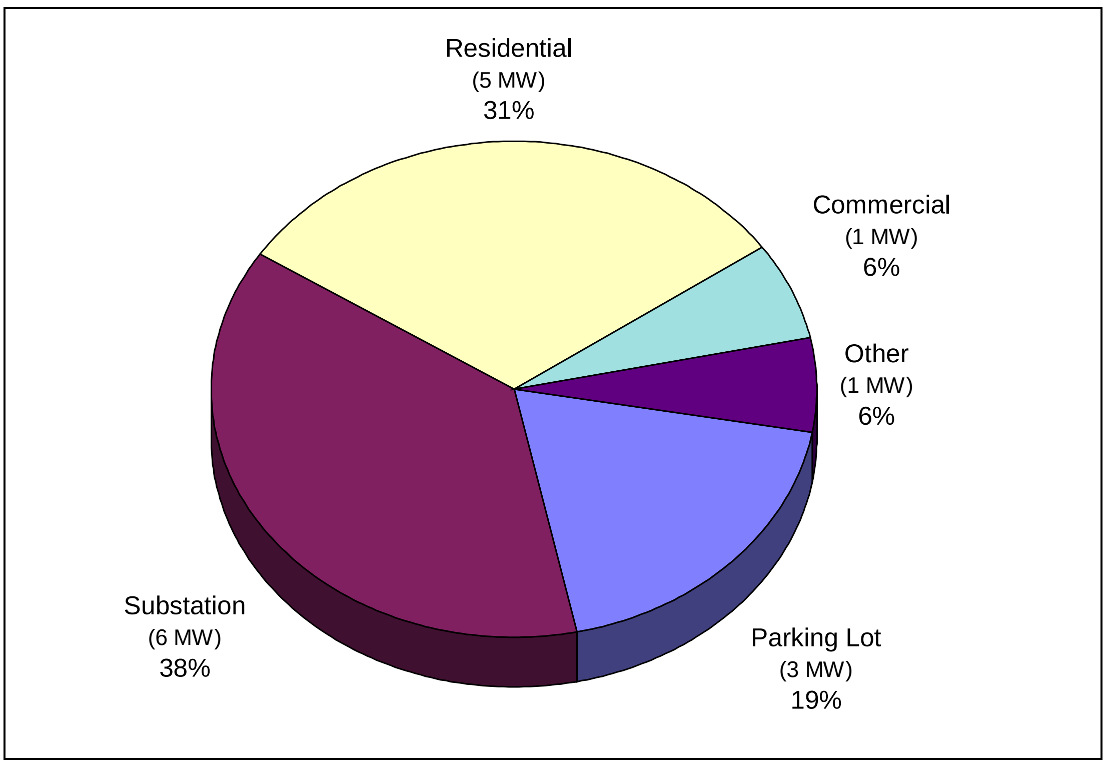


Figure 2-2. Breakdown of 16 MW of SMUD PV applications in 2002 (estimated).

2.2 THE SMUD SYSTEM

The District's forecasted 1996 operating revenues are about $720 million to serve approximately 480,000 customers (90% residential). Figure 2-3 presents a breakdown of the District's operating revenues. Two-thirds of the total revenues are allocated for power purchases and long-term debt service. About $50 million (7%) is allocated for T&D, and of this amount only $12 million is allocated to distribution substations and lines (less than 2.0% of the District's total annual operating revenues). The allocation of operating revenues is the basis of the District's marginal costs and the resulting valuation of distributed PV systems. Table 2-2 presents a summary of SMUD system information.

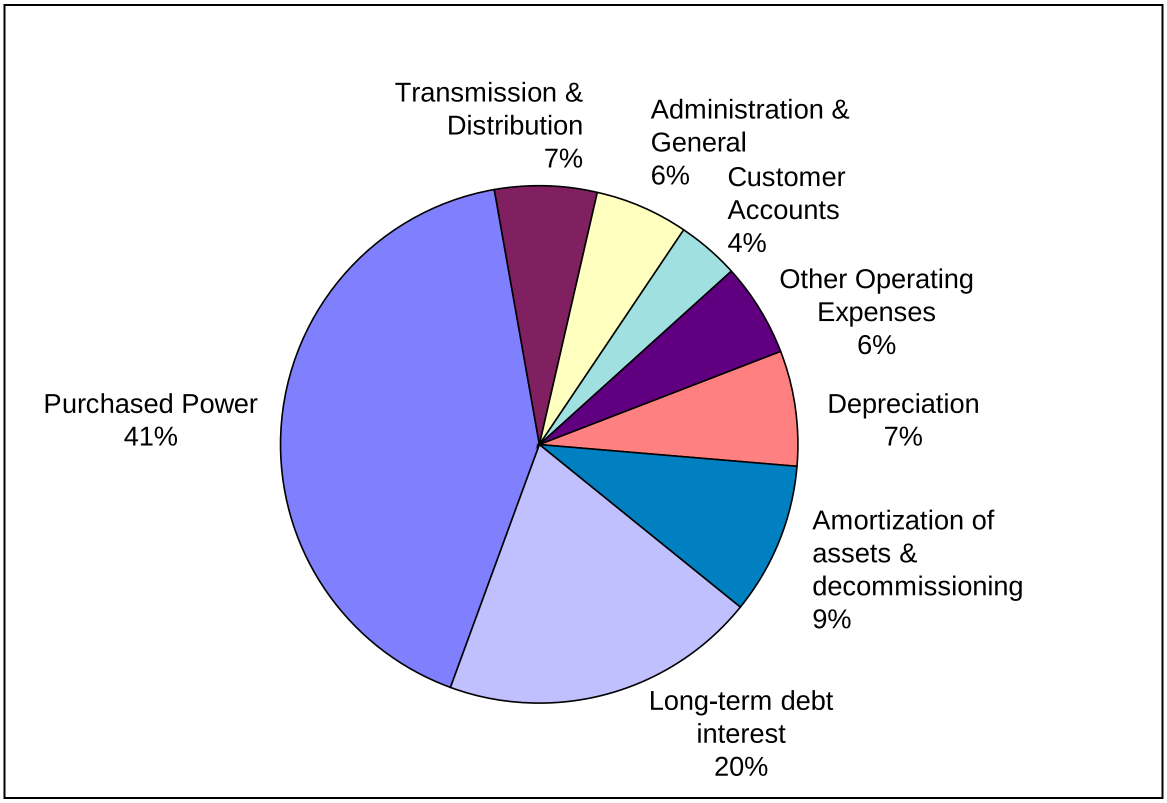


Figure 2-3. District allocation of $720 million in revenue forecasted for 1996.

Table 2-2. SMUD System Information[7]

Number of Customers	The District presently serves 480,000 customers (about 429,000 residential) and is forecasted to serve about 526,000 in the year 2000 and 580,000 in the year 2005. A growth rate of about 1.9% per year. By the year 2000, SMUD projects that it will serve 34,000 new residential and 4,000 new commercial customers.
Service Area Extent	940 mi^2
System Capacity Resources	Existing and planned resources total 2,373 MW in 1995 (about 61% supplied by short & long term purchase contracts, 33% from renewables -- mostly hydro, and 6% from local gas-fired resources).
Systemwide Peak Demand	Unmanaged peak demand in 1995: 2,280 MW. About 2,070 MW managed. Will reach about 2,450 MW in 2000 and about 2,700 MW in 2005 unmanaged load. A forecasted increase of ~1.7%/yr. Summer peak load is about 53% residential, 45% commercial, and 2% agricultural and miscellaneous.
Energy Efficiency and Load Control	1995 net systemwide coincident demand reduction by energy efficiency programs is estimated at 34 MW. 147 GWh of energy savings. SMUD Power System Operations can "dispatch" about 176 MW of potential additional reduction through non-firm tariffs. 210 MW is difference between managed and unmanaged peak.
Systemwide Energy Demand	1995 systemwide energy demand: about 9,100 GWh unmanaged. Projected to increase at about same rate as peak demand (1.9%/yr).
Distribution System Elements	• 14,000 circuit miles • 175 69/12 kV substations (serve 88% of District load) • 250 substation transformers
Distribution System Planning Areas	Distribution system divided into 20 smaller "planning areas" defined by relative electrical and geographic boundaries.
Distribution System Demand Increase	Over next 5 years, non-coincident distribution system demand is forecast to increase by about 155 MW, with over 55%, or 87 MW, in large customer block loads such as a new airport terminal, mall, and Junior Valley College facility.
T&D Voltage Definitions	Bulk Transmission (230 kV and above); Sub Transmission (69 kV and 115 kV); Primary Distribution (4 kV, 12 kV, and 21 kV); and Secondary Distribution (below 4 kV)

[7] Table 2-2 sources: SMUD 1996a, 1996b, 1995 Resource Plan, Load Forecasting and DSM Integration, Structure of Alternative Resource Strategies, SMUD Public Workshop 1995

3. PV System Ratings and Performance

Fixed and tracking flat-plate PV system configurations are considered in this study since almost 100% of the approximately 4.3 MW of PV system capacity purchased and owned by the District since 1984 fits in these two categories. This section describes the procedure used to assign a PV system capacity rating followed by a presentation of PV system performance results. These performance results are used to calculate the PV system benefits to the District and potential bill savings and metering impacts for customer-owned systems.

3.1 Determining PV System Ratings

An accurate PV system capacity rating is important because it is used in resource planning and evaluation to calculate system capacity factor and effective load carrying capability (or credited dependable capacity), and it is usually the basis upon which payments are made to system suppliers. Ratings are typically determined with actual measured performance data once a PV system is installed and operating for at least one month. A procedure to estimate a PV system's rating is presented below by way of example for fixed rooftop PV Pioneer and tracking Hedge substation systems. Since actual measured performance data are not yet available for PV Pioneer systems, this estimated rating procedure is used in this study. This PV system rating procedure can also be used to corroborate the ratings of PV systems bid to utilities through Request for Proposals.

3.1.1 PV System Rating Example #1: SMUD PV Pioneer

A SMUD PV Pioneer system, with 84 Siemens M53 PV modules, is used as an example to illustrate how PV systems are rated and, subsequently, how performance is simulated. There are three basic steps to estimate the rating of a PV system:

1. Determine the PV module output at PVUSA Test Conditions (PTC)[8].
2. Determine PV system loss factors.
3. Multiply the number of PV modules by Module output at PTC by the BOS loss factors:

System Rating = Number of Modules x Module Output at PTC x Loss Factors

The first step is to determine PV module output at PTC. Manufacturers provide PV module ratings under controlled indoor Standard Test Conditions[9] which result in higher output than what is achieved in the field under PTC. For example, Figure 3-1 presents the power-voltage characteristic for the Siemens M53 PV module under STC and PTC. PV module temperature is

8 The Photovoltaics for Utility Scale Applications project method of rating PV systems is widely accepted by the utility industry and is used as the design basis for evaluating SMUD PV systems. PVUSA Test Conditions are defined as 1,000 W/m^2 plane-of-array irradiance, 20°C ambient dry bulb temperature, and 1 m/s wind speed.

9 Standard Test Conditions (STC) are used by manufacturers to assign dc power ratings to PV modules and are conducted under controlled conditions of 1,000 W/m^2 plane-of-array irradiance and 25°C PV cell temperature.

25°C under STC and about 52°C under PTC[10]. Since PV module efficiency declines as the PV module temperature rises, the peak power output decreases from 53 Wdc to about 46 Wdc, a 13 percent reduction.

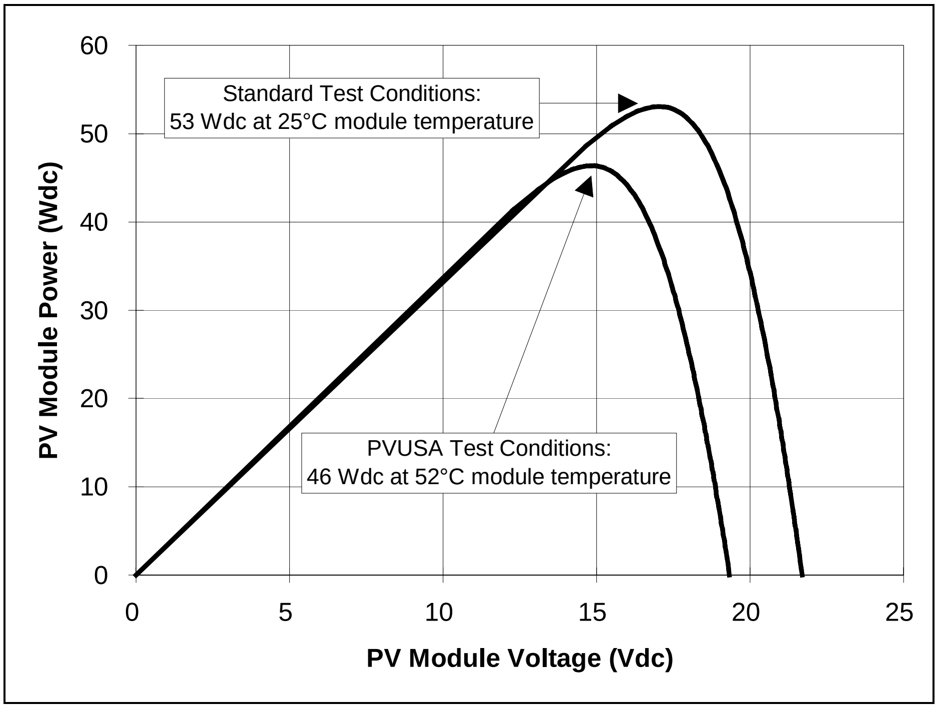


Figure 3-1. PV module power curves at Standard and PVUSA Test Conditions

The second step to determine the PV system rating is to enumerate PV system loss to obtain a realistic system capacity rating under outdoor operating conditions. These losses, for a PV Pioneer system, are presented in Table 3-1. The first column lists the loss factors to arrive at a PV system capacity rating, while the second column contains loss factors used in PVGRID™ to predict hourly and annual energy output.

[10] According to PVUSA, PV module temperatures are typically around 47°C for ground mounted systems (Personal Communication with Tim Townsend, 1995). We estimate that residential rooftop PV temperatures will be significantly higher because of limited convective heat transfer between the module and the roof. 52°C may in fact still be too low at PVUSA Test Conditions. Measurements of PV Pioneer PV module temperatures over a range of ambient conditions are recommended in order to ascertain performance and rating estimates.

Table 3-1. PV Pioneer System Rating and Annual Energy Loss Factors.

	System Rating Calculation[a]	Annual Energy Calculation[b]
DC Cabling[c]	0.988	0.990
Diodes & Connections	0.990	0.992
Mismatch	0.983	0.985
Power Conditioning Unit	0.930	0.915
Soiling[d]	0.995	0.975
Shading Losses	1.000	0.985
Tracking Losses	1.000	1.000
Transformers (daytime)	1.000	1.000
Transformers (nighttime)[e]	1.000	0.990
AC wiring	0.995	0.996
Availability of System[f]	1.000	0.980
Auxiliary loads	1.000	1.000
TOTAL	0.885	0.821

(a) Loss factors are used to convert PV module dc output at PTC to system ac output at PTC.
(b) Loss factors are used in PVGRID annual energy simulations. These are annual average loss factors.
(c) Cabling and equipment losses are smaller for the annual energy calculation due to lower current operating levels throughout the year.
(d) Reduced soiling losses assumed for rating period.
(e) Transformer (tare) losses at night for Omnion 4 kW 2400 Series are 15 W.
(f) Equivalent to one (1) week of downtime per year.

The final step to determine the system capacity rating is to multiply the number of PV modules by the PV module output at PTC by the system loss factors.

For the PV Pioneer, the PTC rating is therefore: 84 modules x 46.4 Wdc x 0.885 = 3.45 kWac.[11]

3.1.2 PV System Rating Example #2: Tracking System at Hedge Substation

The same three step process described in the PV Pioneer example above is used to develop a rating for a single-axis tracking PV system at Hedge substation in a grid-support application. The Hedge PV1 system has 4800 Siemens M53 PV modules. PV module output at PTC is expected to be about 47.6 Wdc, somewhat higher than a rooftop application because of cooler module operating temperatures. Table 3-2 presents the loss factors for this system. The most significant differences between a rooftop PV pioneer fixed system and a substation tracking system are the PCU efficiency, soiling losses, and tracking losses. These loss factors are used in

[11] The combined loss factor for converting the manufacturer's STC module rating of 53 Wdc to a PTC system rating of 3.45 kWac is 0.775. Therefore, a quick way to roughly estimate the rating of a single crystal PV Pioneer system is to multiply the number of PV modules by the module STC rating by 75%.

the PVGRID™ computer simulation program to estimate PV system performance, as described below.

Table 3-2. Substation Tracking System Rating and Annual Energy Loss Factors.

	System Rating Calculation[a]	Annual Energy Calculation[b]
DC Cabling[c]	0.988	0.990
Diodes & Connections	0.990	0.992
Mismatch	0.983	0.985
Power Conditioning Unit	0.950	0.945
Soiling[d]	0.995	0.960
Shading Losses[e]	1.000	0.990
Tracking Losses	1.000	0.992
Transformers (daytime)	0.992	0.993
Transformers (nighttime)	1.000	0.995
AC wiring	0.995	0.996
Availability of System[f]	1.000	0.986
Auxiliary loads	1.000	0.999
TOTAL	0.897	0.835

(a) Loss factors are used to convert PV module dc output at PTC to system ac output at PTC.
(b) Loss factors are used in PVGRID annual energy simulations. These are annual average loss factors.
(c) Cabling and equipment losses are smaller for the annual energy calculation due to lower current operating levels throughout the year.
(d) Reduced soiling losses assumed for rating period.
(e) These are equivalent losses for a back-tracking PV system.
(f) Equivalent to five (5) days of downtime per year.

The tracking substation system PTC rating is: 4800 modules x 47.6 Wdc x 0.897 = 205 kWac.

3.2 PV Performance

This sub-section summarizes the performance of fixed rooftop and tracking substation system designs defined previously. Performance is presented in isolation of utility and customer loads. Subsequent sections contain discussions of the interaction of PV output with loads to determine PV system benefits (see Utility Benefits Supporting Analysis section).

3.2.1 PVGRID™ Computer Simulation Program

Once the PV system design, rating, and loss factors are defined, the PVGRID™ computer simulation program is used to estimate system performance. A simulation program enables:

1. Calculation of benefits of PV systems to the District and its customers;

2. Comparison between long-term average and specific year energy and capacity projections;

3. Sensitivity analysis of different PV system designs (e.g., tracking versus fixed, and variations in tilt and azimuth angles); and

4. Comparison between projected and actual PV system performance.

PVGRID™ has been used extensively to accurately simulate the performance of utility grid-connected photovoltaic systems (Wenger and Hoff 1995). It has undergone thorough testing and field validation: Based on accurate solar irradiance data, the software predicts PV output to within 2% of measured data. PVGRID™ utilizes hourly weather data (8,760 hours per year) allowing the user flexibility to model a variety of PV system configurations and technologies.

3.2.2 Climatic Data

Two sources of climatic data are used in this study to estimate PV system performance. The first is Sacramento Typical Meteorological Year (TMY) data derived from the National Solar Resource Data Base over the period 1961-1990 (NREL 1995). TMY data represent long-term typical climatic conditions and are used to determine the average PV system performance and capacity factor. The second source of weather data is measured at the PVUSA site in Davis, California, about 12 miles west of downtown Sacramento. Measured climatic data that is coincident with measured load data during 1994 are used in this study to determine the PV system effective load carrying capability (or credited capacity). Both of these climatic data files contain hourly values of global horizontal and direct normal irradiance, ambient temperature, and wind speed.

3.2.3 Average Year Performance

Table 3-3 presents calculated PV performance and weather statistics for an average year using Sacramento TMY data. A nominal 3.45 kWac PV Pioneer system that is tilted at 20 degrees from the horizontal and faces due south should produce around 6,200 kWh annually for about a 21% capacity factor and an average annual sunlight to electric conversion efficiency of about 9%. A nominal 205 kWac one-axis tracking substation system should produce around 443,000 kWh per year, with about a 25% capacity factor and conversion efficiency of about 9%. These capacity factors are used in the calculation of energy benefits to the SMUD system.

Figure 3-2 presents normalized PV system performance, where monthly energy output is shown for a 1 kW equivalent PV system capacity. This figure illustrates the gain in production that is captured by tracking the sun, most significantly during the summer peaking season. A tracking system will produce about 20% more energy per year than a fixed system of the same rating. Tracking also provides higher utility credited capacity which is described in subsequent sections.

Table 3-3. PV Performance and Weather Statistics for an Average Year[12]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
PV Pioneer, Fixed[13]													
Production (kWh)	238	341	501	615	707	707	741	710	618	491	298	224	6,192
Capacity Factor (%)	9.3	14.7	19.5	24.8	27.6	28.5	28.9	27.7	24.9	19.1	12.0	8.7	20.5
Efficiency (%)	9.0	9.0	9.0	8.9	8.7	8.6	8.5	8.5	8.5	8.6	8.7	8.9	8.7
Hedge PV1, Tracking[14]													
Production (kWh)	12,221	19,673	33,291	45,022	55,009	58,715	60,436	55,158	43,989	31,379	16,541	11,476	442,909
Capacity Factor (%)	8.0	14.3	21.8	30.5	36.1	39.8	39.6	36.2	29.8	20.6	11.2	7.5	24.7
Efficiency (%)	9.1	9.3	9.6	9.6	9.3	9.3	9.1	9.2	9.1	9.1	9.0	8.9	9.2
Weather[15]													
Ambient Temp. (C)	9	12	13	16	21	24	26	27	25	20	14	9	19
Windspeed (m/sec)	3.5	3.5	4.1	4.4	4.6	4.6	4.2	4.5	3.7	3.2	2.5	2.0	3.9
DNI (kWh/m^2)	53	89	134	179	229	257	275	252	207	160	88	60	1,981
GHI (kWh/m^2)	58	83	131	177	223	235	244	219	173	123	70	53	1,789

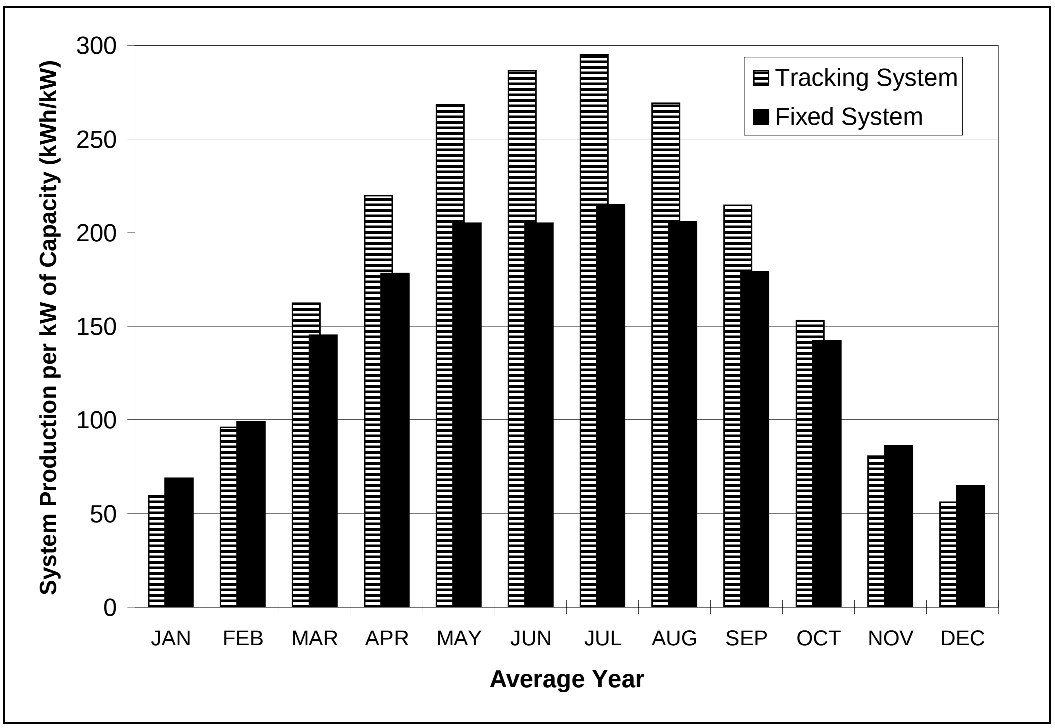


Figure 3-2. Tracking boosts energy production about 20% over fixed systems.

---

[12] Based on PVGRID™ simulations and NREL Typical Meteorological Year (TMY2) hourly data

[13] Based on a 3.45 kWac rating: 84 Siemens M53 modules (35.9 m^2 gross area), tilted 20 deg, oriented due south

[14] Based on a 205 kWac rating: 4,800 Siemens M53 modules (2,049 m^2 gross area) horiz. north-south axis tracker

[15] Ambient Temperature and Windspeed are daytime average readings, DNI is defined as Direct Normal Insolation, and GHI is defined as Global Horizontal Insolation

3.2.4 Performance During 1994 and 1995

It is of interest to look at performance estimates during 1994 and 1995 in order to (a) Assess the difference between specific year and long-term average year performance and (b) Assess how well PV systems are performing by finding the difference between measured production and simulated production. These two issues are relevant for utility planners who must plan on -- and depend on -- the short term and long term performance of PV systems, particularly as penetrations increase.

3.2.4.1 YEAR-BY-YEAR FLUCTUATIONS

Figure 3-3 and Figure 3-4 present calculated monthly and annual capacity factors for the PV Pioneer and Hedge PV1 systems, respectively. Capacity factors for 1994 and 1995 are shown, in addition to capacity factors based on long-term average TMY weather data. These figures provide an indication of the fluctuations in solar resource availability and the dependability of year-by-year performance estimates that is crucial to resource planning. It is evident that resource fluctuations are most pronounced during the winter and "swing" months in spring and fall, caused by variations in precipitation and cloud cover. Year-by-year fluctuations during the crucial summer production months are minimal, however, and this results in a very tight distribution in the annual capacity factor. The expected annual capacity factor ranges between 20% and 21% and between 25% and 26% for the fixed and tracking systems, respectively. Table 3-4 presents these performance data.

As is consistent with most U.S. locations, the solar resource does not fluctuate much from one year to the next on an annual, aggregated basis. Disruptions in the upper atmosphere caused by events such as volcanic eruptions can, however, can cause a 2 to 4 year downward trend in resource availability that is about 25% at nadir, then rebounding to previous levels.

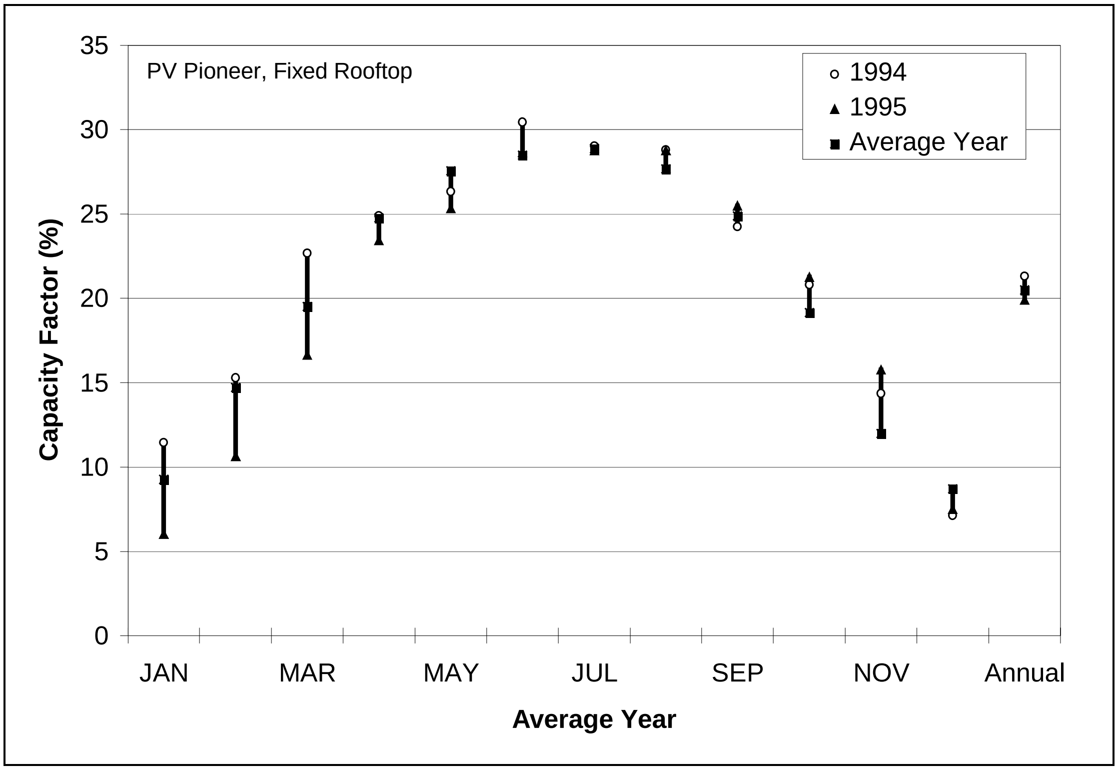


Figure 3-3. Capacity factors for PV Pioneer (fixed rooftop) system.

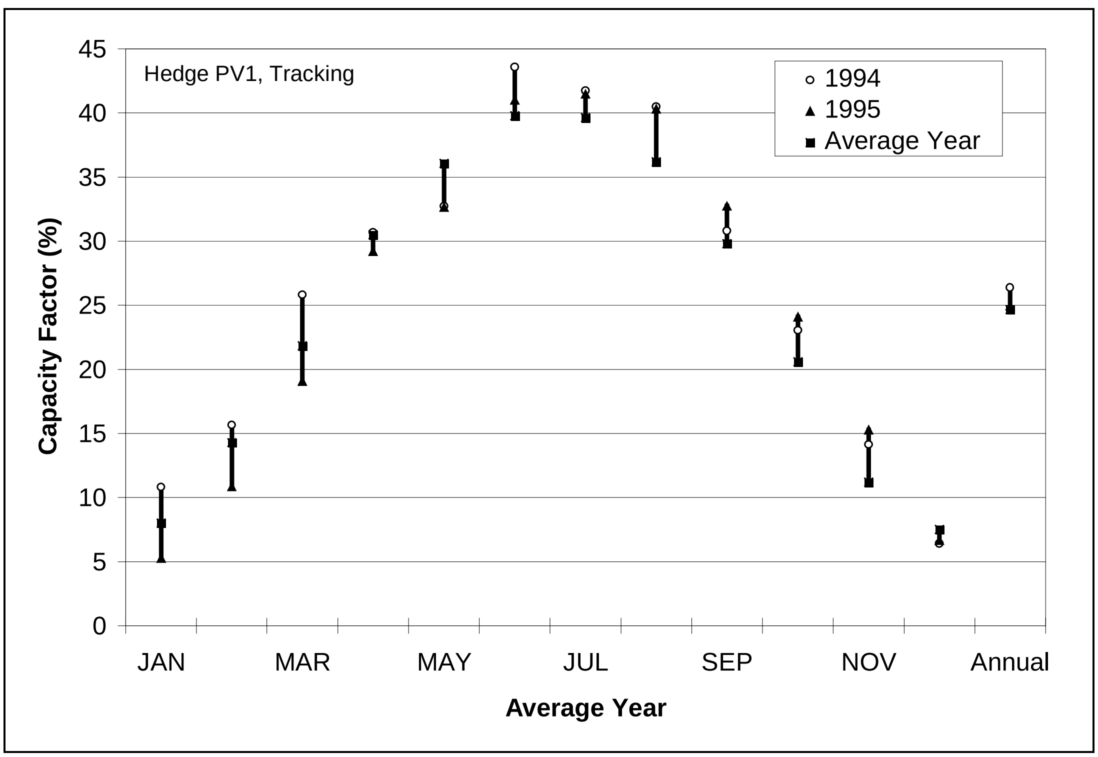


Figure 3-4. Capacity factors for Hedge Substation PV1 (tracking) system.

Table 3-4. PV Performance Comparison: Average Year vs. 1994-5[16]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
PV Pioneer, Fixed[17]													
'94 Production (kWh)	294	355	583	619	676	757	746	739	603	534	357	183	6,445
'95 Production (kWh)	154	246	427	582	650	712	738	738	633	545	391	192	6,010
Avg Production(kWh)	**238**	**341**	**501**	**615**	**707**	**707**	**741**	**710**	**618**	**491**	**298**	**224**	**6,192**
'94 Cap. Factor (%)	11.5	15.3	22.7	24.9	26.3	30.5	29.0	28.8	24.3	20.8	14.4	7.1	21.3
'95 Cap. Factor (%)	6.0	10.6	16.6	23.4	25.3	28.7	28.8	28.8	25.5	21.2	15.8	7.5	19.9
Avg Cap. Factor (%)	**9.3**	**14.7**	**19.5**	**24.8**	**27.6**	**28.5**	**28.9**	**27.7**	**24.9**	**19.1**	**12.0**	**8.7**	**20.5**
Hedge PV1, Tracking[18]													
'94 Production (kWh)	16,481	21,565	39,379	45,292	49,913	64,328	63,648	61,758	45,470	35,152	20,850	9,781	473,617
'95 Production (kWh)	8,033	14,945	29,079	43,076	49,790	60,513	63,256	61,459	48,308	36,732	22,522	10,142	447,855
Avg Production(kWh)	**12,221**	**19,673**	**33,291**	**45,022**	**55,009**	**58,715**	**60,436**	**55,158**	**43,989**	**31,379**	**16,541**	**11,476**	**442,909**
'94 Cap. Factor (%)	10.8	15.7	25.8	30.7	32.7	43.6	41.7	40.5	30.8	23.0	14.1	6.4	26.4
'95 Cap. Factor (%)	5.3	10.8	19.1	29.2	32.6	41.0	41.5	40.3	32.7	24.1	15.3	6.6	24.9
Avg Cap. Factor (%)	**8.0**	**14.3**	**21.8**	**30.5**	**36.1**	**39.8**	**39.6**	**36.2**	**29.8**	**20.6**	**11.2**	**7.5**	**24.7**

3.2.4.2 PERFORMANCE INDEX AND EQUIVALENT FORCED OUTAGE RATE

A PV Performance Index (PI) was recently developed to help determine how well PV systems are performing in the field (Hoff and Wenger, 1994; Townsend, et.al. 1994). The PI is defined as the measured, or actual, PV system production divided by the expected PV system production. The expected production is based on computer performance tools such as PVGRID™ that take into account system losses that occur in the field in the course of "normal operation", such as soiling and shadowing of arrays.

A Performance Index of 100% indicates the system is operating as designed with no unplanned full or partial outages. The PI can be determined instantaneously to help troubleshoot PV system problems on a real-time basis, or it can be determined on a longer-term basis, such as monthly or annually for trending purposes. A PI greater than 90% indicates excellent performance, with good performance between 80% and 90%, fair performance between 70% and 80% and a PI of less than 70% indicates poor performance.

The Equivalent Forced Outage Rate (EFOR), a term that utilities are more familiar with, can be determined by simply subtracting the PI from 100%. The EFOR is typically used on a monthly or annual basis to indicate the percentage of time an electric facility is completely or partially forced out of service by equipment failure or other unexpected events. Figure 3-5 presents the EFOR for the Hedge Substation PV1 system during 1995 based on preliminary data (PVUSA,

---

[16] Based on PVGRID™ simulations and NREL Typical Meteorological Year (TMY2) hourly data for average year performance and actual measured weather data at Davis, CA for 1994 and 1995.

[17] Based on a 3.45 kWac rating: 84 Siemens M53 modules (35.9 m^2 gross area), tilted 20 deg, oriented due south

[18] Based on a 205 kWac rating: 4,800 Siemens M53 modules (2,049 m^2 gross area) horiz. north-south axis tracker

1996). The EFOR indicates significant operation problems during the first quarter of 1995, followed by very good performance for the remainder of the year. The PV1 system yielded a 14% EFOR for 1995 (equivalent to a 86% Annual Performance Index, see Figure 3-6); better than the 15%-20% EFOR that is typical for a utility's fossil generating fleet. The Hedge PV1 inverters had significant operation problems during January-March. Without these problems, the annual EFOR is in the excellent range at 9% (equivalent to an annual PI of 91%). Presumably these inverter problems have been resolved and excellent operation is expected for 1996. Data collection is presently in process that will enable the PI and EFOR to be determined for other SMUD systems in the future.

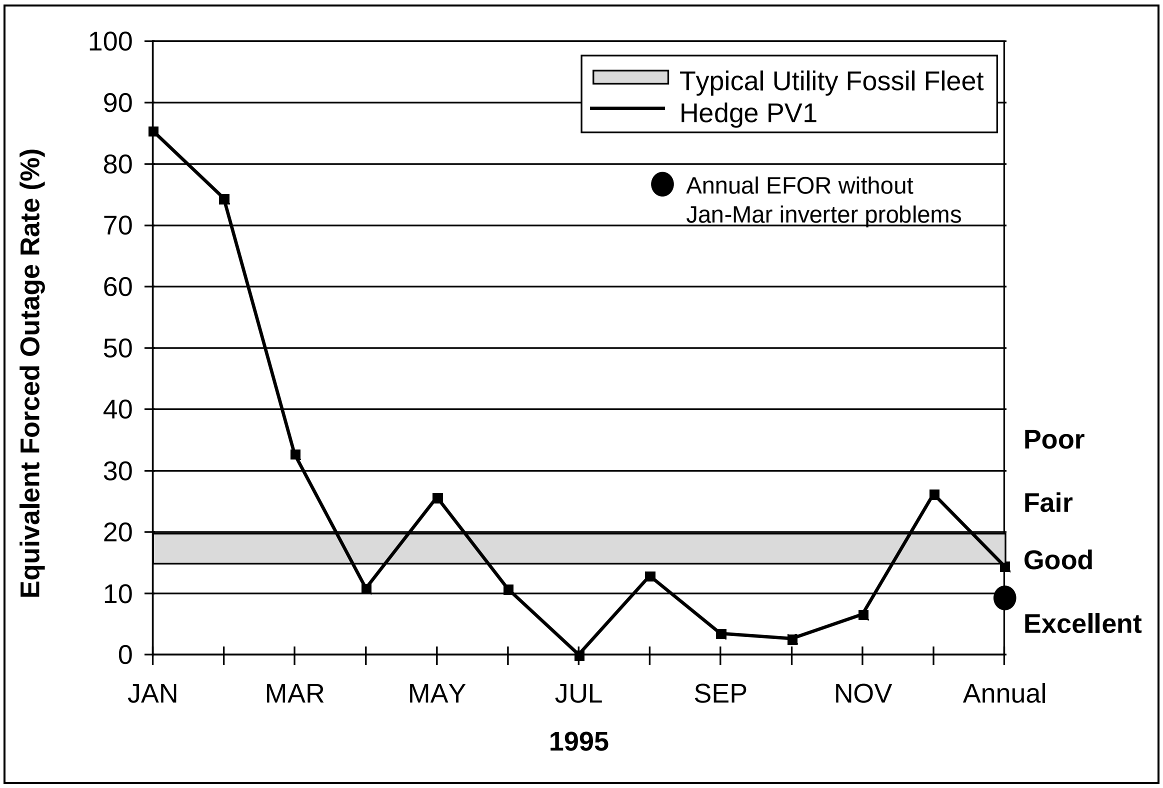


Figure 3-5. Equivalent Forced Outage Rate for Hedge PV1 system.

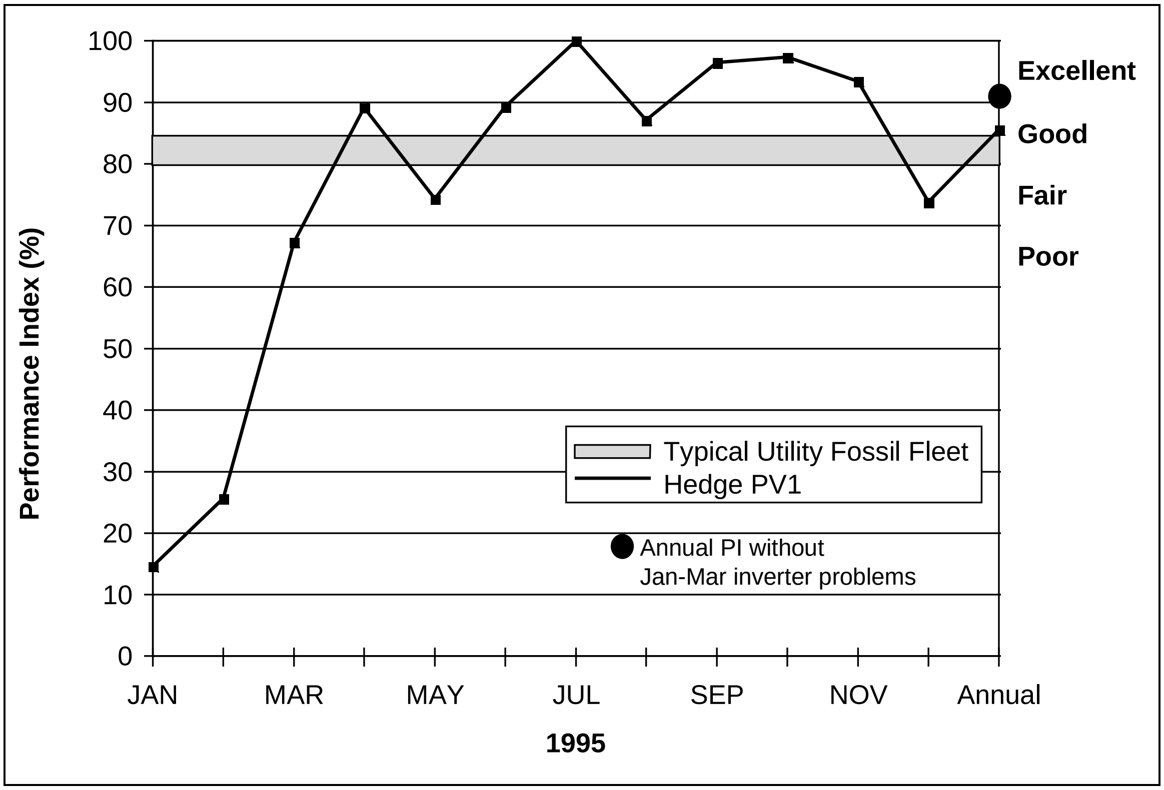


Figure 3-6. Performance Index for Hedge PV1 system.

3.3 Comments on the Energy Potential Factor (EPF)

The EPF, or Energy Potential Factor was introduced by SMUD and adopted by the Utility PhotoVoltaic Group as an alternate rating method that accounts for the improved performance of tracking systems (Osborn and Collier 1995, UPVG 1995). The purpose of the EPF is to allow direct comparison between fixed and tracking PV system <u>prices</u> by "crediting" the extra energy delivered by tracking PV. A north-south single-axis tracking system located in Sacramento, CA has an EPF of 1.23. For example, a tracking PV system that costs $6,000/kWac would be adjusted to about $4,900/kWac on an EPF basis. The EPF is estimated as follows (UPVG 1995):

$$\mathrm{EPF} = \frac{\left[\dfrac{\text{Average Site}-\text{Specific Daily Solar Radiation}\,(\mathrm{kWh/m^2}-\mathrm{day})}{\text{Reference Irradiance}\,(\mathrm{kW/m^2})}\right]}{\left[\dfrac{\text{Fixed Flat}-\text{Plate Site}-\text{Specific Daily Solar Radiation}\,(\mathrm{kWh/m^2}-\mathrm{day})}{\text{Reference Irradiance}\,(\mathrm{kW/m^2})}\right]}$$

The EPF, based solely on the available solar resource, is an energy-based factor that does not take into account added capacity and localized benefits. Table 3-5 provides EPF estimates for PV systems located in Sacramento using weather data supplied by NREL (NREL 1994). The utility benefits results in this study seem to support the use of such a factor. For example compare the tracking and fixed benefits from this study, subtracting out economic development benefits since these are technology independent. A tracking PV system value of $2,580/kW is compared with a fixed PV system value of $2,100/kW, both at secondary distribution. This nets out to about a 23% gain, the same 1.23 EPF value calculated using NREL data. Of the 23% gain, 7% is derived from added capacity benefits and 16% from added energy benefits.

Table 3-5. Energy Potential Factors for Sacramento PV Systems

PV System Type	Reference Irradiance (W/m^2)	Site Specific Solar Radiation (kWh/m^2-day)	Energy Potential Factor (EPF)
Fixed, 0^o Tilt	1000	4.9	0.89
Fixed, 23^o Tilt	1000	5.5	1.00
Fixed, 39^o Tilt (reference)	1000	5.5	1.00
North-South Axis Tracker (0^o Tilt)	1000	6.8	1.23
North-South Axis Tracker (23^o Tilt)	1000	7.3	1.33
Polar-Axis Tracker	1000	7.4	1.35
Two-Axis Tracker	1000	7.6	1.38
Polar-Axis Tracker, Concentrator	850	5.3	1.13
Two-Axis Tracker, Concentrator	850	5.5	1.18

This highlights the potential danger in assigning an EPF based solely on added energy production potential. This is because of the complex number of design and application variables including, tracking strategy, tilt angle, array orientation, PV module and cell technology, interconnection voltage level, distribution site location, and customer building application. Each of these variables will change the total benefits picture rendering a potentially endless number of EPF calculations.

One could argue that, for example, a building integrated roofing system that captures roofing credits and reduces cooling load might be assigned an EPF greater than 1.0. *For simplification purposes, however, the SMUD/UPVG methodology appears to be a reasonable proxy*.

It is suggested that further work be conducted to investigate the development of a series of EPFs for different PV applications. This could provide a more equitable basis for evaluating the prices of competing systems and could also help suppliers optimally design their systems. In essence, the utility buyer would be sending a value signal to suppliers so they could respond with an optimal system design. Also, it is suggested that the EPF be called the "Extra Performance Factor", or some other acronym, since the EPF goes beyond just accounting for additional energy potential/production, such as the added benefits of capacity and perhaps dual-use benefits.

4. Utility Benefits

This section presents the calculation of benefits delivered by distributed PV systems to the District. Table 4-1 presents a list of these benefits with a brief description. The premise is that the aggregate, or "stacking", of benefits yields the total value of distributed PV for utility-owned systems. The total benefits can then be translated into the break-even PV system price. Alternatively, the total benefits can be converted into a levelized energy value.

As summarized in Table 4-2, utility benefits are evaluated for two PV system types interconnected at four different T&D voltage levels and sited within 14 different distribution planning areas. This section focuses on the benefits results. The section "Utility Benefits Supporting Analysis" provides methodological details.

Table 4-1. Utility Benefits Evaluated

Benefits	**Description**
Energy	Avoided marginal cost of systemwide energy production
Capacity	Avoided marginal cost of systemwide generation capacity
Distribution	Distribution capacity investment deferral
Sub-Transmission	Sub-Transmission capacity investment deferral
Bulk-Transmission	Transmission capacity investment deferral
Losses	Electric loss reduction (accounted for in each benefit)
REPI	Renewable Energy Production Incentive. Federal payment to the District as incentive to invest in renewable resources
Externalities	Value of reduced fossil emissions
Green Pricing	Voluntary monthly contributions from PV Pioneers
Fuel Price Risk Mitigation[19]	Value of reducing risk from uncertain gas price projections
Service Revenues (Economic Development)	Net service revenues from local PV manufacturing plant (result of economic development efforts)

[19] The District placed a first-year value of $0.015/kWh for externalities in its 1995 Marginal Cost Study which includes the value of fuel price risk mitigation. Therefore, even though externalities and fuel price risk mitigation values are calculated separately in this case study, the sum of these values equals a first-year value of $0.015/kWh.

Table 4-2. Cases Evaluated

Utility and Location	Sacramento Municipal Utility District, Sacramento, CA
PV system types	PV Pioneer: Fixed flatplate residential rooftop system, tilted at 20 deg, composite orientation of 30 deg west of south Grid-Support: Horizontal north-south single-axis tracking flatplate, substation system
Interconnection levels	Bulk-Transmission (230kV), Sub-Transmission (69, 115kV), Primary Distribution (21, 12, 4kV), Secondary Distribution (below 4kV)
Distribution Planning Areas	14 (per the District's 1995 Marginal Cost Update report)

4.1 Economic Assumptions and Input Data

The majority of the data and economic assumptions used in this study were obtained in meetings with District personnel and from District documents including the 1995 Marginal Cost Update, 1995 Integrated Resource Plan, and Five Year Distribution System Business Plan (SMUD 1995a-i). Table 4-3 presents the main economic assumptions for the baseline analysis. Other District-specific data used in the study can be found in various subsections throughout this report and in the Appendix.

Table 4-3. Economic Assumptions

Base year of study	1996
Study period duration and PV system life	30 years
Utility discount rate (nominal)	6.6%
Utility discount rate (real)	2.9%
Escalation rate (consumer price index)	3.6%
Accounting method	End of year
Federal Solar Investment Tax Credit	n/a - Muni is tax exempt
Renewable Energy Production Incentive (REPI)	$0.015/kWh over 10 years

4.2 VALUATION APPROACH

Two approaches are used to determine the utility benefits of distributed PV systems.

1. The first is a "detailed" approach that uses year-by-year marginal cost data developed by the District to calculate the avoided costs of energy, capacity, transmission, and distribution. The detailed approach utilizes hourly District load and PV performance data to determine the PV system credited capacity by way of a loss of load probability calculation. Other detailed analyses were completed to determine the direct benefits of a new local PV manufacturing facility and reducing the risk of future fuel price uncertainty. The results presented in the following subsections (4.3, 4.4, and 4.5) are based on the detailed analysis approach.

2. The second valuation approach is a simplified method using the QuickScreen software package. QuickScreen takes as input singular "rolled up" investment cost information to determine utility benefits. In addition, the simplified approach does not require hourly PV performance simulations or hourly load data since QuickScreen automatically calculates the PV system capacity credit and capacity factor. QuickScreen results, including a comparison to the detailed analysis approach, are presented in subsection 4.6 and in the Appendix.

4.3 TRACKING PV SYSTEM BENEFITS

Figure 4-1 presents the value of tracking PV systems at 4 different interconnection levels. The benefits range between $2,900-$3,300/kW. The range is a result of variations in T&D deferral benefits and reduced electric losses. Table 4-4 and Figure 4-2 present the benefits data and percentages by category. Significant benefits have been determined for service revenues derived from a new PV manufacturing plant, externalities including fuel price risk mitigation, and Renewable Energy Production Incentive (REPI) payments. The added "non-traditional" benefits double the traditional energy, capacity, and T&D benefits.

Service revenues and REPI payments are split off in Figure 4-2 because of their uncertainty. In this study, it is assumed that the District's 50-MW RFP for renewable resources will result in a new PV manufacturing facility in the Sacramento area (SMUD, 1996d). The increased revenue (minus costs) from electricity sales to this new PV facility is the "Service Revenues" benefit. Therefore, the Service Revenues benefit is shown with a dotted line since it is dependent on the outcome of the RFP process.

REPI payments are provided by the U.S. Department of Energy for solar, wind, and biomass resources owned by public power agencies such as the District. The stability and tenure of REPI is somewhat tenuous as it must survive the rigors of the annual appropriations process. For this reason, although the District has received REPI payments in the past, the REPI benefit is also depicted with a dotted line because of future uncertainty.

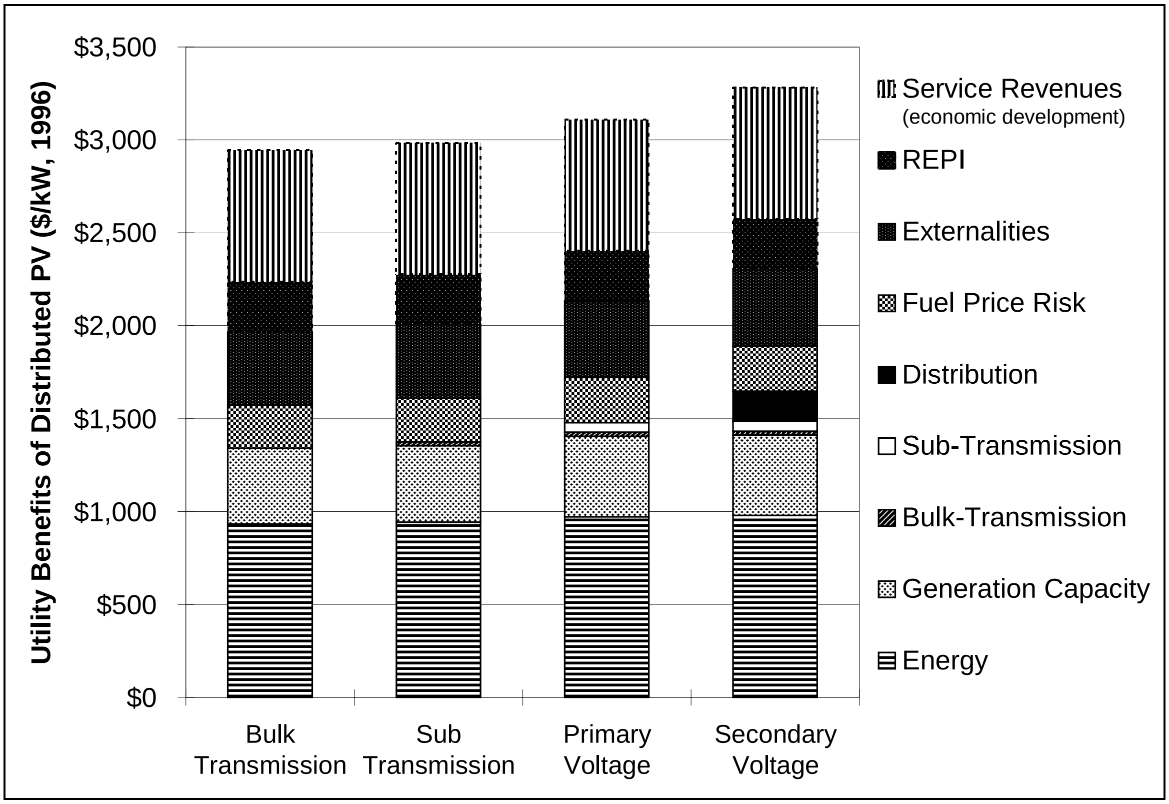


Figure 4-1. Utility benefits of tracking PV systems vs. T&D voltage levels.

Table 4-4. Utility Benefits of Tracking PV ($/kW, 1996).

BENEFITS	Bulk Transmission	Sub Transmission	Primary Voltage	Secondary Voltage
Service Revenues	$708	$708	$708	$708
REPI	$269	$269	$269	$269
Externalities	$394	$398	$411	$414
Fuel Price Risk	$234	$236	$243	$245
Distribution	0	0	0	$160
Sub-Transmission	$0	0	$54	$54
Bulk-Transmission	0	$21	$22	$22
Generation Capacity	$407	$412	$431	$432
Energy	$934	$943	$974	$980
Losses	included	included	included	included
TOTAL	**$2,946**	**$2,987**	**$3,112**	**$3,284**

Notes: Transmission (230kV), Sub-Transmission (69kV & 115kV), Primary Distribution (4kV, 12kV, 21kV), and Secondary Distribution (below 4 kV). Electric loss savings are included in each of the benefit categories.

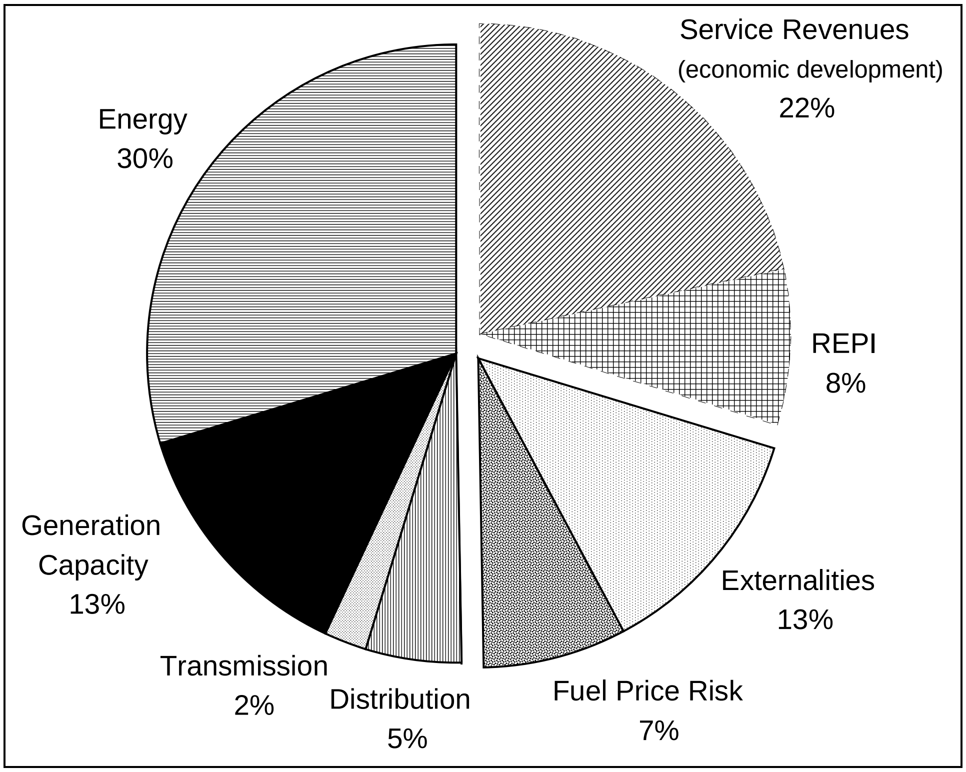


Figure 4-2. Utility benefits of a tracking PV system (% of total benefits).

4.4 Fixed PV System Benefits

Figure 4-3 presents the value of fixed PV systems at 4 different interconnection levels. PV Pioneer green pricing benefits are included for distribution interconnection levels. The total benefits range between $2,500-$2,800/kW. Table 4-5 and Figure 4-4 present the benefits data and percentages by category. As with substation-sited tracking PV systems, significant benefits have been determined for service revenues derived from a new PV manufacturing plant, externalities including fuel price risk mitigation, and REPI payments. Without these additional benefits, the total benefits would be about $1,200/kW. Again, the added "non-traditional" benefits double the traditional energy, capacity, and T&D benefits.

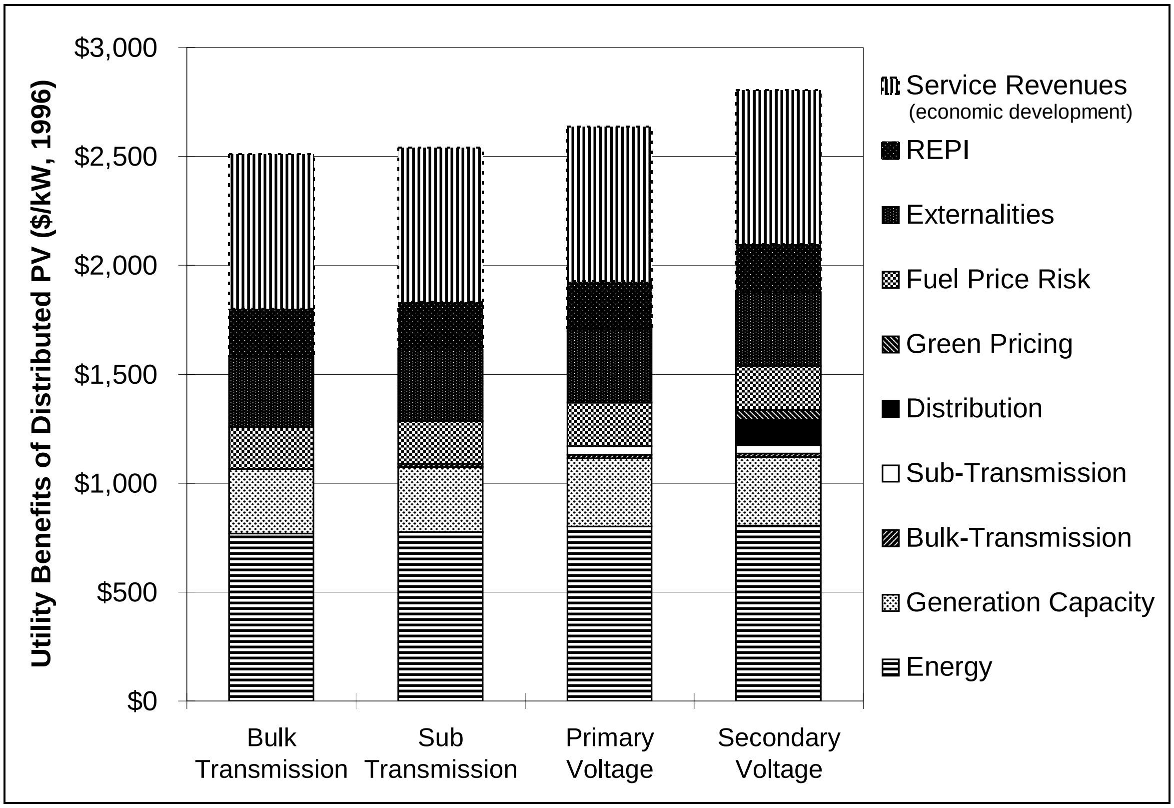


Figure 4-3. Utility benefits of fixed PV systems vs. T&D voltage levels.

Table 4-5. Utility Benefits of Fixed PV ($/kW, 1996).

BENEFITS	Bulk Transmission	Sub Transmission	Primary Voltage	Secondary Voltage
Service Revenues	$708	$708	$708	$708
REPI	$221	$221	$221	$221
Externalities	$324	$327	$338	$340
Fuel Price Risk	$192	$194	$200	$201
Green Pricing	$0	$0	$44	$44
Distribution	$0	$0	$0	$117
Sub-Transmission	$0	$0	$39	$39
Bulk-Transmission	$0	$15	$16	$16
Generation Capacity	$296	$300	$314	$315
Energy	$768	$775	$800	$805
Losses	included	included	included	included
TOTAL	**$2,509**	**$2,540**	**$2,680**	**$2,806**

Notes: Transmission (230kV), Sub-Transmission (69kV & 115kV), Primary Distribution (4kV, 12kV, 21kV), and Secondary Distribution (below 4 kV). Electric loss savings are included in each of the benefit categories.

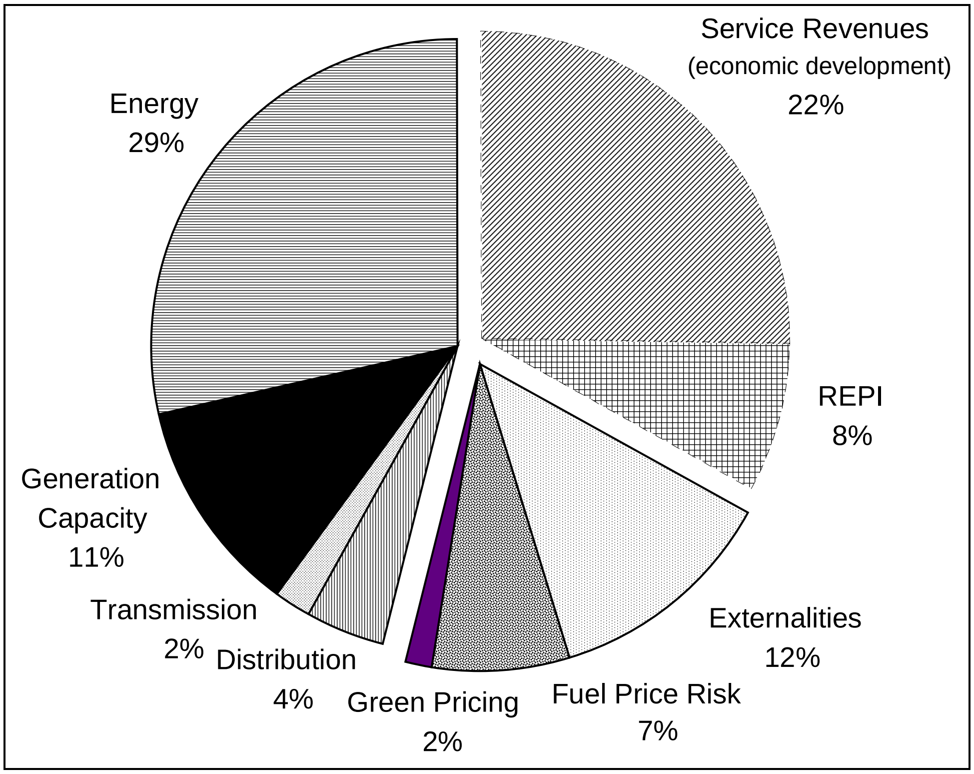


Figure 4-4. Utility benefits of a PV Pioneer system (% of total benefits).

4.5 Benefits Summary

Figure 4-5 presents the value of tracking and fixed PV systems at distribution voltage levels. These are the likely interconnection locations for distributed PV systems. The present value of benefits, in 1996 dollars, range from $2,600/kW to $3,300/kW, depending on system type and interconnection location. These values are shown in the shaded cells of Table 4-6. Table 4-6 also shows the total benefits in 30-yr levelized formats based on capacity factors of 24.7% and 20.3% for tracking and fixed PV systems, respectively, and the economic assumptions of Table 4-3. The benefits of Table 4-6 must be balanced against the costs of purchasing, operating, and maintaining PV systems to determine economic viability. See the Commercialization Strategies section for PV system economics.

Table 4-7 and Table 4-8 present the total levelized benefits, in nominal and real 1996 dollars, over different periods of performance, assuming a year 2000 starting date. The levelized benefits range from about $0.09/kWh to $0.12/kWh on a nominal basis, and from about $0.07/kWh to $0.09/kWh on a real basis.[20]

[20] Levelized benefits allow a direct comparison between costs and benefits, and across competing resources. Levelization is typically used in resource planning, but seldom used in independent power producer (IPP) financing and the formulation of power purchase agreements. An IPP will typically propose a payment structure that varies from one year to the next depending on the contract term, debt to equity ratio, required coverage ratio, required rates of return, depreciation, tax credits, and other financial parameters. Ultimately, the power purchase agreement is negotiated on a case-by-case basis to balance the needs of both parties.

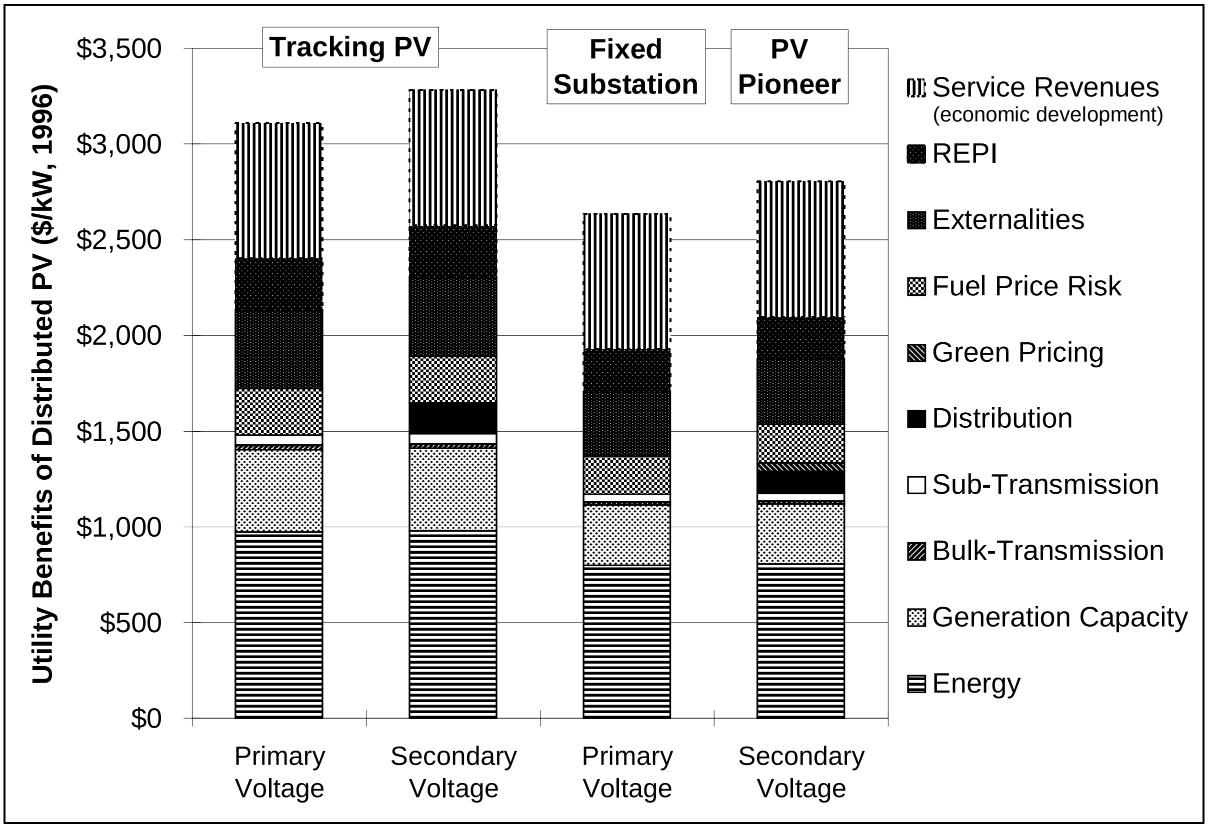


Figure 4-5. Utility benefits of tracking & fixed PV at distribution voltages.

Table 4-6. Total Benefits for 1996: Present Value ($/kW) and Levelized ($/kWh, nominal)[21]

	Bulk Transmission	Sub Transmission	Primary Distribution	Secondary Distribution
Tracking PV ($/kW)	$2,950	$2,990	**$3,110**	**$3,280**
Fixed PV ($/kW)	$2,510	$2,540	**$2,640**	**$2,810**
Tracking PV ($/kWh)	$0.105	$0.107	**$0.111**	**$0.117**
Fixed PV ($/kWh)	$0.109	$0.111	**$0.115**	**$0.122**

[21] Based on the benefits in Table 4-4 and Table 4-5, capacity factors of 20.3% and 24.7% for fixed and tracking PV systems per Table 4-2, respectively, and economic assumptions of Table 4-3.

Table 4-7. Levelized Benefits for Year 2000 (1996$, nominal)[22]

Study Period	Levelized Benefits for Resources at These Voltage Levels ($/kWh)			
	Bulk Transmission	**Sub Transmission**	**Primary Distribution**	**Secondary Distribution**
Tracking PV				
10-yr	$0.093	$0.095	$0.098	$0.103
15-yr	$0.095	$0.097	$0.100	$0.106
20-yr	$0.099	$0.101	$0.105	$0.111
25-yr	$0.104	$0.105	$0.110	$0.116
30-yr	$0.108	$0.110	$0.115	$0.121
Fixed PV				
10-yr	$0.096	$0.097	$0.101	$0.105
15-yr	$0.098	$0.099	$0.103	$0.108
20-yr	$0.102	$0.104	$0.108	$0.113
25-yr	$0.107	$0.108	$0.113	$0.119
30-yr	$0.112	$0.113	$0.118	$0.124

Table 4-8. Levelized Benefits for Year 2000 (1996$, real)[23]

Study Period	Levelized Benefits for Resources at These Voltage Levels ($/kWh)			
	Bulk Transmission	**Sub Transmission**	**Primary Distribution**	**Secondary Distribution**
Tracking PV				
10-yr	0.078	0.079	0.082	0.086
15-yr	0.074	0.075	0.078	0.082
20-yr	0.072	0.073	0.076	0.081
25-yr	0.071	0.072	0.075	0.080
30-yr	0.070	0.071	0.075	0.079
Fixed PV				
10-yr	0.080	0.081	0.084	0.088
15-yr	0.076	0.077	0.080	0.084
20-yr	0.074	0.075	0.078	0.082
25-yr	0.073	0.074	0.077	0.081
30-yr	0.073	0.074	0.077	0.081

[22] The different "study periods" correspond to the period of time over which the PV plant is operating and the benefits are calculated and levelized. The PV plant has no salvage value at the end of the study period. Economic assumptions of Table 4-3 are used, except for the variation in study period duration. Values are based on a nominal discount rate of 6.6% which includes inflation. Values are presented in nominal, or current, dollars.

[23] Same comment per Table 4-7, only based on a real discount rate of 2.9%, thereby removing inflation. Values are shown on a real, or constant, basis. These values vary slightly as a function of the performance period because inflation is not constant during the first 20 years of the benefits stream.

4.6 UTILITY BENEFITS CALCULATIONS WITH QUICKSCREEN SOFTWARE

A computer software package called QuickScreen, previously developed by Pacific Energy Group under contract to the U.S. Department of Energy, was used in this study to re-calculate the utility benefits of distributed PV (Wenger and Hoff 1995b). QuickScreen is a Windows point-and-click package that is intended to provide a simple-to-use tool that requires minimal data input and analysis effort to evaluate specific distributed PV applications (Wenger, Hoff, and Furseth 1996). Extensive documentation and on-line help is available within the QuickScreen software. In effect, using the District as a case study provided an opportunity to further validate QuickScreen and to demonstrate how other utilities can easily investigate the viability of distributed PV applications.

QuickScreen captures distributed PV system benefits in eight categories: Externalities, distribution, sub-transmission, bulk-transmission, generation capacity, energy, and "other".[24] Electric loss savings are embedded in each of the relevant categories. Figure 4-6 shows the benefits calculations from four of the detailed analyses and compares them with the QuickScreen (QS) results. The figure shows that QuickScreen accurately calculates the total benefits and the individual benefits categories. The overall QuickScreen results are within 5% of the detailed analysis results. QuickScreen software printouts of charts and data sheets are provided in the Appendices.

QuickScreen software can be obtained from Christy Herig of the National Renewable Energy Laboratory at 303-384-6546, or from John Stevens of Sandia National Laboratories at 505-844-7717.

---

[24] The "other" benefits account for service revenues from locating a PV manufacturing facility in the District's service area and for REPI payments. These two benefits are specific to the District and are not explicitly calculated within QuickScreen. The utility analyst must calculate these benefits separately and then input them into the "other" category within QuickScreen. Evaluation of renewable tax credits and tax incentives may be added to the next version of QuickScreen.

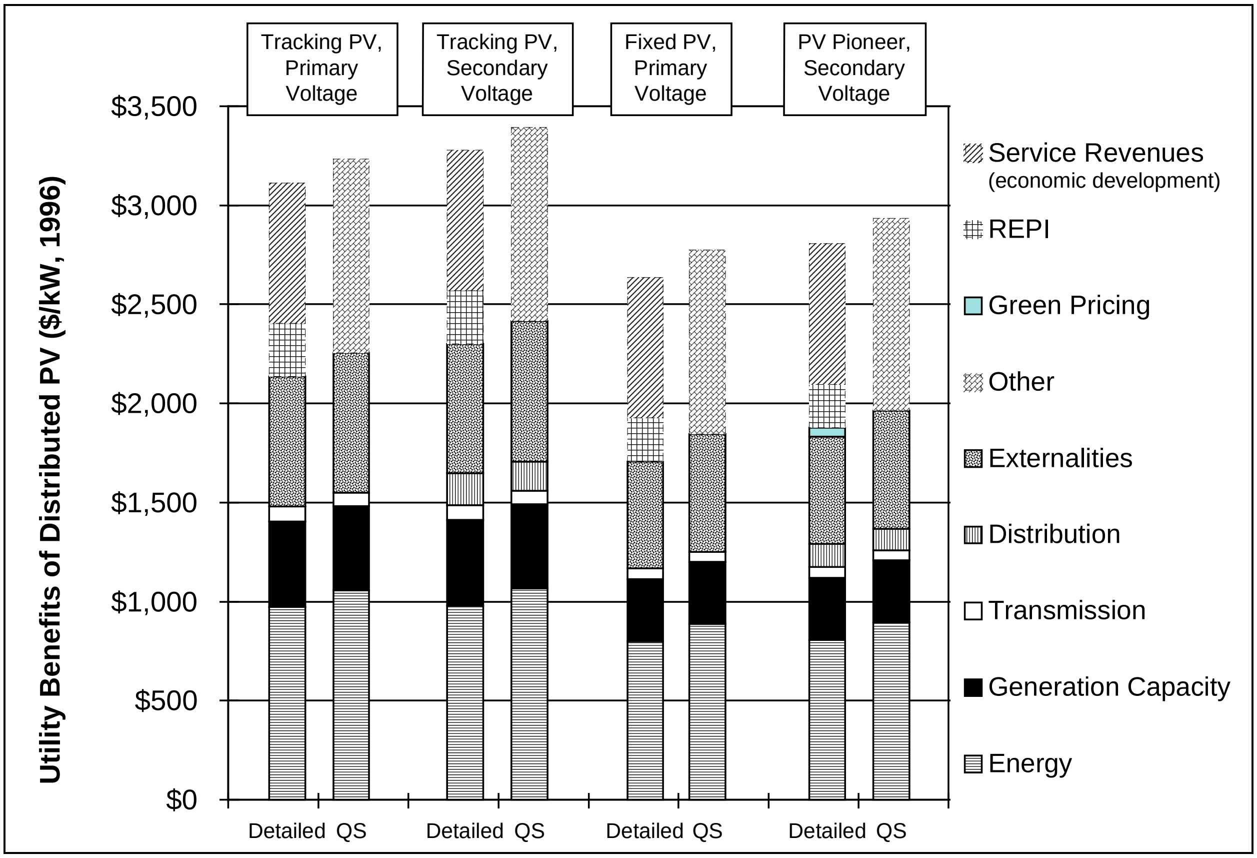


Figure 4-6. Benefits comparison: Detailed vs. QuickScreen analysis.

5. Commercialization Strategies

One objective of this study is to provide insight on the viability and timing of commercialization paths for grid-connected photovoltaics. This section discusses a few possible strategies.

5.1 SUSTAINED ORDERLY DEVELOPMENT

The District has embarked on a path of continued PV procurements with the expectation that PV prices will decline as long as the District, with other utilities and energy providers, provide a sustained commitment to purchase PV systems in sufficient quantities. In response to this firm utility market, manufacturers and suppliers of PV equipment will make the investments and innovations necessary to compete and capture market share. As prices decline, PV becomes increasingly competitive with other resource options until it reaches a point of cost-effectiveness without subsidy. This commercialization strategy has been referred to as Sustained Orderly Development or "SOD" (Osborn and Collier 1995 and 1996, Aitken 1992).

There are three elements to this commercialization strategy: Volume purchases, price reductions, and closing the gap between price and value or willingness to pay. Figure 5-1 shows PV system cost curves based on historical (actual) and projected costs.[25] PV system prices have declined dramatically since 1984, at a rate of about 5.5%/year, representing a real decline in PV prices of 9%/year in the absence of inflation. Lines A & B depict this "business as usual" trend. Line C is the projected PV system cost curve that the District expects from the SOD process.

The range of utility benefits calculated using the District as a case study is overlaid on the cost curves to determine the timing of cost-effectiveness. This benefit range, from $1,700/kW-$3,500/kW, encompasses the value of tracking and fixed PV systems at different interconnection locations, time frames of deployment, and benefits categories. The following observations are made regarding Figure 5-1:

- PV system prices are presently twice as high as needed to achieve cost-effectiveness without subsidies;
- PV will be cost-effective for SMUD systems in the 2000-2004 time frame, assuming that PV costs follow the SOD trajectory and the utility benefits remain fairly constant;
- The SOD strategy could accelerate PV commercialization of SMUD-owned systems by about 6 years; and
- Under the "business as usual" scenario, to reach a PV system price of $3,000/kWac in 2006 requires a cumulative worldwide sales volume of about 3,200 MW, or about seven times the cumulative sales to date. In contrast, the SOD cost curve results in a $3,000/kWac PV system price around the year 2000.[26]

---

[25] PV system costs in Figure 5-1 include sales tax on hardware and District added costs, such as interconnection, District labor, administration, overhead, AFUDC, and operations and maintenance.

[26] Sales tax and District ownership costs are expected to add about $550/kW (1996$) to the system price for a total PV system cost to the District of $3,550/kW in the year 2000.

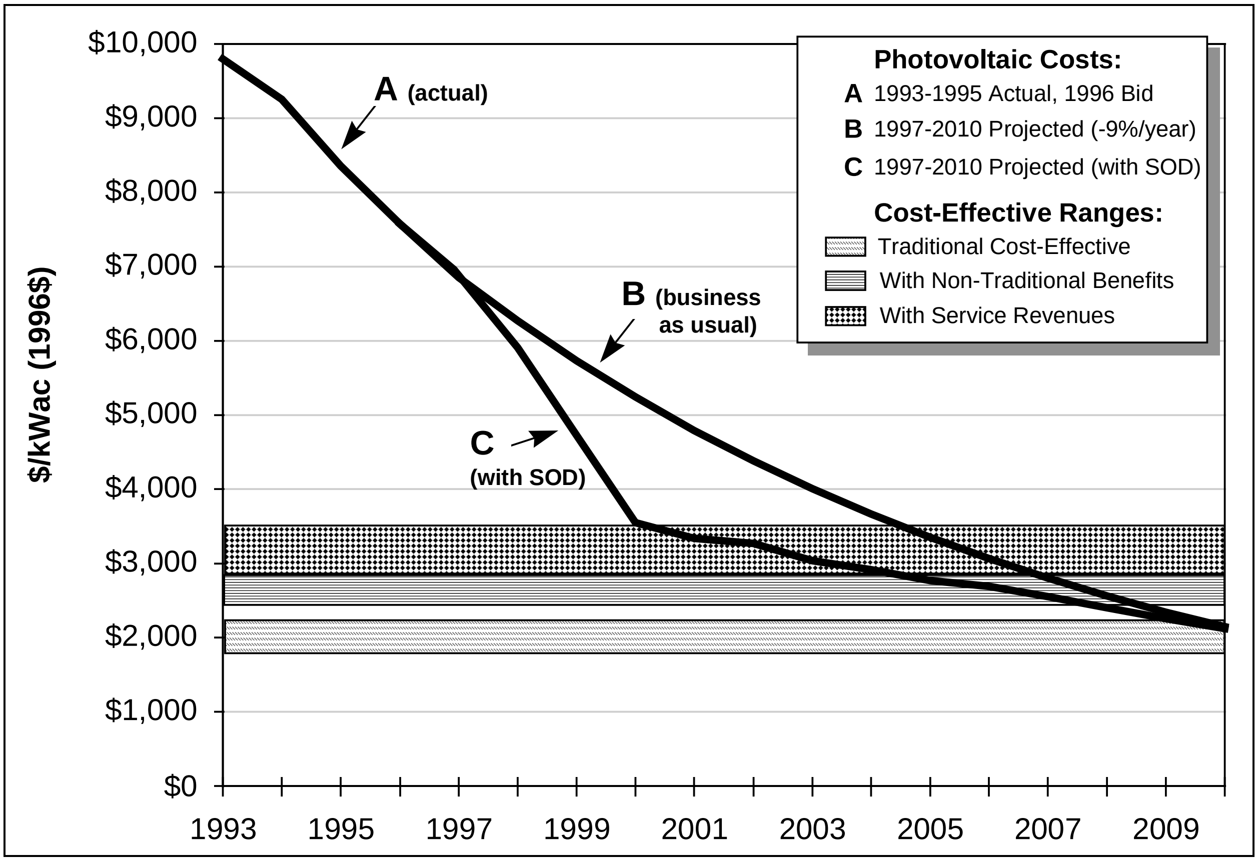


Figure 5-1. PV cost trajectories and cost-effectiveness ranges (real 1996$).[27]

Data Sources for Figure 5-1

The PV system cost trajectories of Figure 5-1 are based on historical (actual) and projected prices for turnkey, installed, PV systems. Table 5-9 and Figure 5-2 show historical grid-support tracking PV system prices. Two "models" are used to project future PV system prices. Both are extrapolations of historical price drops and are considered the "business as usual" scenario. The exponential model simply extends the exponential decline in prices at the historical rate of 5.5% (a real decline of 9%/year in the absence of inflation). The second model coincides almost exactly with the first (see Figure 5-2). It is based on the observation that every doubling in cumulative worldwide PV sales volume results in an 18% decrease in PV module prices (Jensen 1996).

Figure 5-3 provides the sales volume required to achieve the projected price drops of Figure 5-2. For example, cumulative PV module sales reached about 400 MW in 1995. If the market

---

[27] Photovoltaic Costs: "A 1993-1995 Actual, 1996 Bid" based on District PV system costs; "B 1997-2010 Projected" based on historical annual reduction of 9% per year; "C 1997-2010 Projected" based on the District's cost reduction estimates of 17% annual average to the year 2000 and 5% annual average from 2000 to 2010. Cost-Effective Ranges: "Traditional Cost-Effective" based on the District's Renewable Marginal Costs; "With Non-Traditional Benefits" include green pricing, distribution capacity benefits, and REPI payments; "With Service Revenues" accounts for the projected revenue increase from locating a PV manufacturer in the District's service area.

continues to expand at a rate of 18%/year, a doubling of cumulative sales -- to 800 MW -- would be achieved by 1999. This doubling will cut module prices by 18%. Assuming that PV module prices will continue to constitute half of the PV system price, system prices will be halved every 8 years on a real basis. Therefore, based on 1995 PV system prices of about $7,250/kWac, they will be halved to about $3,600/kWac in 2003, and then halved again to $1,800/kWac in 2011.

The Sustained Orderly Development cost trajectory is based on data supplied by the District. The District estimates that their PV system costs will be reduced by 17%/year on average to the year 2000 and by 5%/year on average from 2000 to 2010 (R. Davi, SMUD, 1996).

Table 5-9. PV Module Sales and System Costs[a]

		PV System Price, Business as Usual[b]		PV System Cost to SMUD, Business as Usual[c]		PV System Cost to SMUD with SOD[c]	
Year	Cumulative PV Module Sales (MW)	Nominal Dollars ($/kWac)	Real 1996$ ($/kWac)	Nominal Dollars ($/kWac)	Real 1996$ ($/kWac)	Nominal Dollars ($/kWac)	Real 1996$ ($/kWac)
1984	-	$12,850	$19,400	-	-	-	-
1985	-	$12,600	$18,350	-	-	-	-
1986	-	$12,050	$17,000	-	-	-	-
1989	-	$10,750	$13,650	-	-	-	-
1992	-	$8,800	$10,100	-	-	-	-
1993	-	$7,700	$8,550	-	-	$8,840	$9,800
1994	-	$7,500	$8,050	-	-	$8,640	$9,260
1995	400	$7,000	$7,250	-	-	$8,080	$8,360
1996	500	$6,650	$6,650	-	-	$7,580	$7,580
1997	610	$6,300	$6,050	$7,090	$6,850	$7,090	$6,850
1998	750	$5,950	$5,550	$6,720	$6,270	$6,330	$5,910
1999	910	$5,600	$5,100	$6,360	$5,730	$5,240	$4,730
2000	1,100	$5,300	$4,700	$6,020	$5,240	$4,070	$3,550
2001	1,300	$5,050	$4,250	$5,690	$4,790	$3,960	$3,330
2002	1,600	$4,800	$3,900	$5,390	$4,380	$4,020	$3,270
2003	1,900	$4,500	$3,550	$5,100	$4,010	$3,870	$3,040
2004	2,300	$4,300	$3,250	$4,830	$3,670	$3,840	$2,920
2005	2,700	$4,050	$3,000	$4,570	$3,350	$3,780	$2,770
2006	3,200	$3,850	$2,700	$4,320	$3,070	$3,790	$2,690
2007	3,800	$3,600	$2,500	$4,090	$2,800	$3,730	$2,550
2008	4,500	$3,450	$2,300	$3,870	$2,560	$3,630	$2,400
2009	5,400	$3,250	$2,100	$3,670	$2,340	$3,530	$2,260
2010	6,400	$3,050	$1,900	$3,470	$2,140	$3,430	$2,120

[a] PV module sales assume 18%/year sustained growth rate. Real 1996$, or constant dollars, assume 3.5% inflation rate.

[b] Turnkey PV system prices are not on an EPF basis and do not include sales tax or utility added costs. Actual turnkey PV system prices in Table 5-9 are as follows: 1984=Carrisa 1B; 1985=SMUD PV-2; 1986=Austin PV-2; 1989=PVUSA US1; 1992=PVUSA Kerman; 1993=Hedge PV1; 1994=Hedge PV2; 1995=Hedge PV3.

[c] PV system cost to SMUD includes sales tax on hardware and District added costs, such as interconnection, District Labor, administration, overhead, AFUDC, and operations and maintenance.

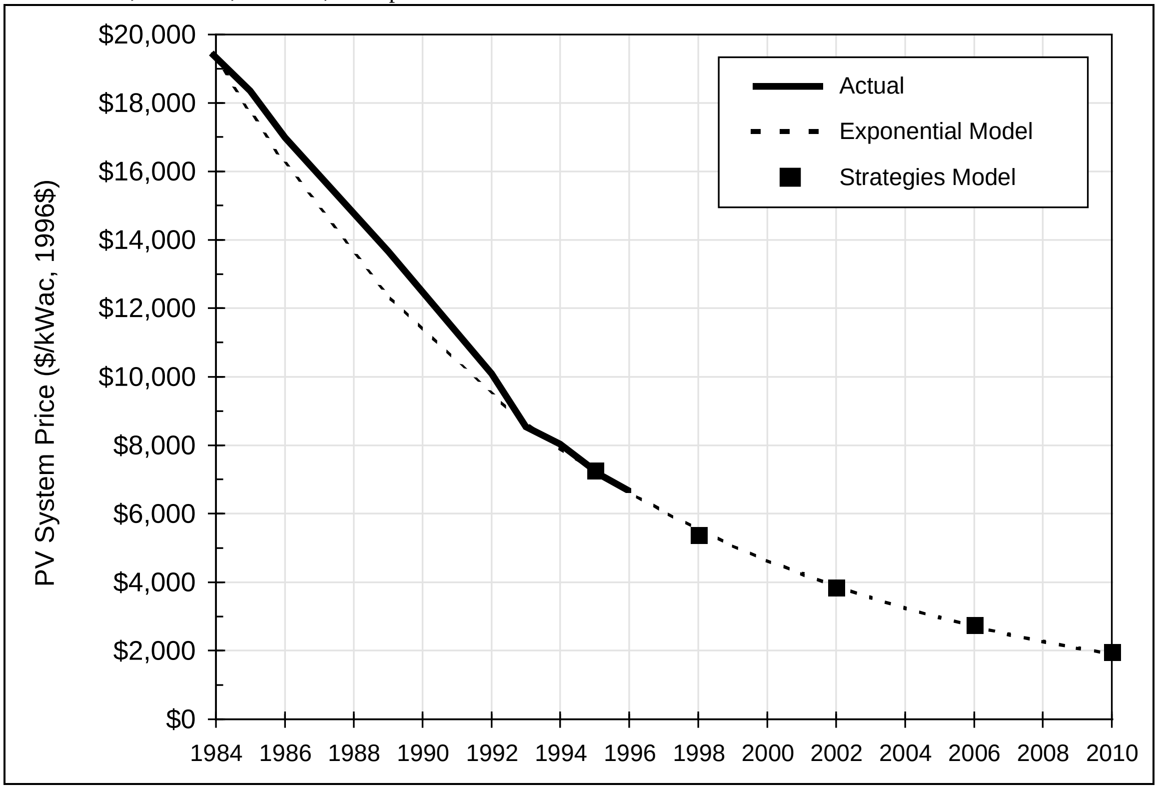


Figure 5-2. PV system price reduction, business as usual scenario (real 1996$).

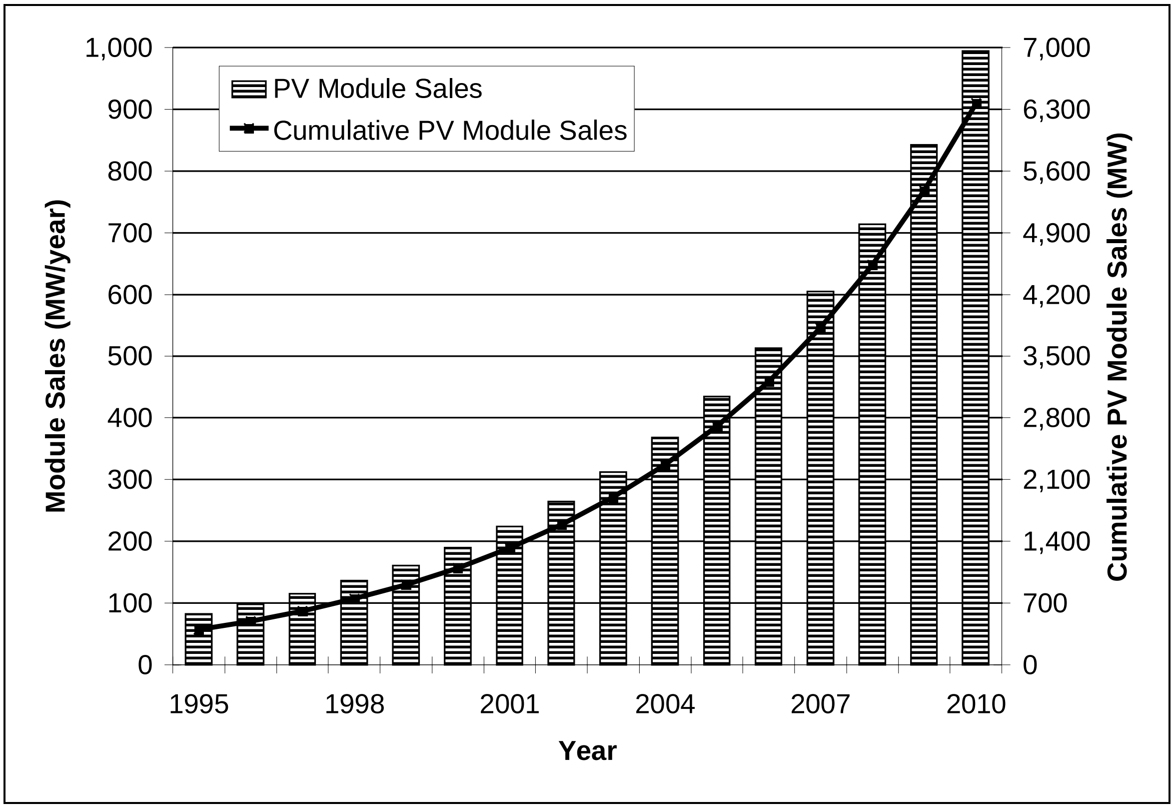


Figure 5-3. PV module sales required to achieve price curve of Figure 5-2.

5.2 MULTI-MEGAWATT IPP STRATEGY

This strategy calls for the construction and third-party financing of large multi-MW PV plants by Independent Power Producers (IPPs). These IPPs secure power purchase contracts from retail electricity providers. Amoco/Enron Solar Power Development Company of Houston, Texas (a joint venture that is the parent company of Solarex Corporation, the U.S's second largest PV module manufacturer) is pursuing this strategy and has proposed to build power plants ranging in size from about 4 MW in Hawaii at a cost of $1,750/kW to 150 MW in India at an undisclosed cost (Utility PhotoVoltaic Group and Amoco/Enron joint press release, January 5, 1996 and The Solar Letter, December 22, 1995). It has been variously reported that Amoco/Enron is willing to sign contracts beginning at $0.05/kWh to $0.06/kWh in the first year and escalating thereafter roughly at inflation. A first-year payment rate of $0.055/kWh has been attributed to a proposed Amoco/Enron multi-MW facility in the Nevada Solar Enterprise Zone.

Amoco/Enron Solar Power Development is seeking to redefine the market by greatly accelerating manufacturing investment and volume, coupled with aggressive pricing that is far below the Sustained Orderly Development PV price projections. Some industry observers speculate, however, that Amoco/Enron's strategy to capture market share requires significant forward pricing and up-front investments to build manufacturing facilities and power projects. In turn, these investments will result in very large financial losses that, over a period of time, the company will not be inclined to sustain and ultimately will alter its strategy or pull out of the business. In any case, Solarex is building their first dedicated thin film plant in Virginia where a $0.75/W state incentive is available up to a capacity of 6 MW per year from 1995 through 1999.

Cost-effective distributed PV plants can be installed much earlier than projected if a company like Amoco/Enron is successful. Their success would alter the face of the PV and energy industries. The Amoco/Enron joint venture, however, has yet to install a single kW of PV and many years and millions of dollars will pass before it will be known if they can deliver on their large-scale IPP strategy in a profitable and sustainable way. As such, Amoco/Enron's progress will continue to be closely watched by the energy industry and financial markets.

5.3 NICHE MARKET APPROACH

This strategy centers around the identification and exploitation of niche markets that are profitable today, but are not likely in very large quantities. The niche market approach directly engages utility customers, the end-user. There are a number of strategies that can be pursued to directly engage retail electric customers to purchase, finance, or lease PV systems. These strategies depend on the existence of a number of incentives that are available only to customers or third parties who directly own PV systems, including:

- compensation for power at retail electric rates
- willingness to pay premiums for clean power
- willingness to pay to be an innovator
- special tariffs, rate-based incentives, or metering options
- tax credits
- financing options
- depreciation options

The niche market approach dictates that any one incentive in isolation is not enough to make a difference in the market, but in aggregate may be enough to form a significant niche market. The best niche markets, for example, are locations with a good solar resource, high utility rates, net metering, tax credits, and progressive state government, regulatory, and utility support.

To illustrate the economics of the niche market customer, suppose the District was able to work with a builder to offer new home buyers an opportunity to finance a 2 kW rooftop PV system. Assume that the PV system cost is $3,000/kW, the loan rate is 7% over 30 years without a down-payment, net metering is available, and electricity rates will increase 2.3%/year. The result is that the customer would have almost no out-of-pocket expenses from the very first year, and the cumulative cash flow would reach zero, or break even, in only 5 years. This is shown in Figure 5-4. The customer would benefit with a net present value of almost $400 in 1996 dollars. Similar results can be attained by offering a low interest (3%) loan at a PV system price of $4,000/kW.

There are certain states in the U.S. where the economics of PV is significantly better than for District residents. Recent research, for example, shows that PV break-even costs exceeding $7,000/kW are available in certain niche markets such as new residential developments in Hawaii. This is due to an excellent solar resource, high utility rates, and favorable state solar tax credits. Some industry participants believe that exploitation of these types of niche markets is a promising strategy for speeding the commercialization of grid-connected photovoltaics.

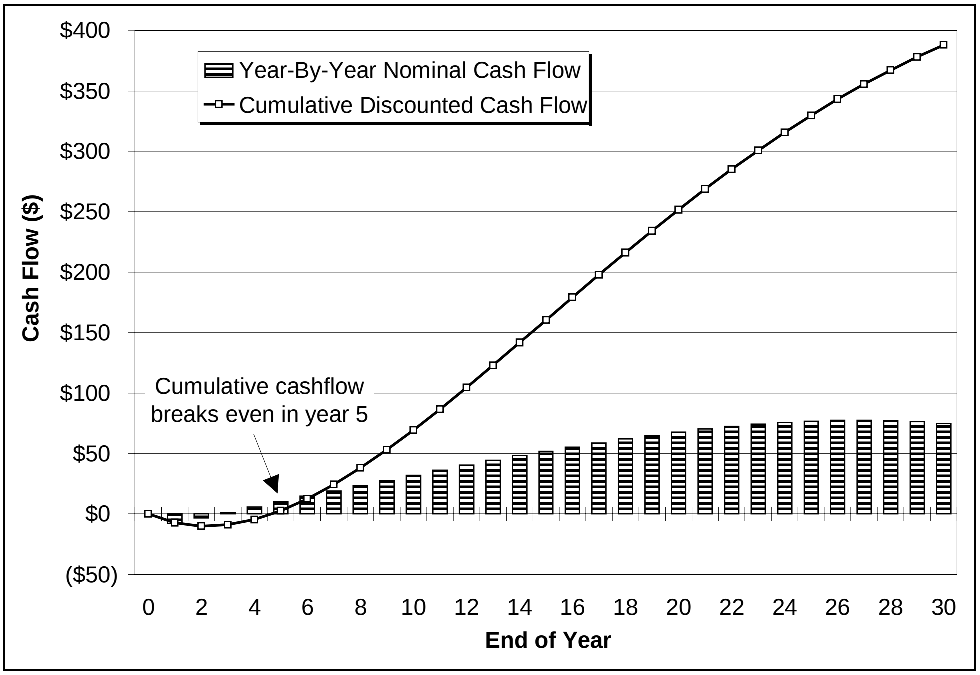


Figure 5-4. Customer cash flows for a 2-kW PV system financed over 30 years.

5.4 TECHNOLOGY BREAKTHROUGHS AND OTHER WILD CARDS

There are a number of possible "wild cards" that could propel the market and drive prices downward faster than projected, including large investments in manufacturing expansion to capture production economies, technology breakthroughs, electric utility restructuring, higher than forecasted fossil fuel prices, and environmental crises that spur investment, both private and public, in renewable energy technologies. Many large oil and gas companies recognize the possible emergence of photovoltaics under these scenarios and have hedged the risk of competition by investing in the technology. It stands to reason that utilities and their customers may make similar investments, although perhaps variously motivated. In any case, the future is impossible to predict, but many forward looking entities are making investments now that will position them later should a watershed event occur.

6. The Market for Utility- and Customer-Owned PV

This section presents marginal demand curves for utility- and customer-owned PV systems within the District. *The results are not intended to quantify the projected demand for systems, but are intended to place an upper bound on the quantity (MW) of distributed PV systems that could be economically deployed within the District*.

6.1 Utility-Owned PV Systems

Figure 6-1 shows the marginal demand for District-owned tracking PV systems. In essence, 2 MW of tracking PV systems could be economically deployed each year at a PV price, including District ownership costs, of about $3,300/kW. This is because of the service revenues the District would gain from a new manufacturing facility from which it is assumed the District would purchase 2 MW/year of PV, on average. An additional 20 MW could be economically installed each year at a turnkey system price of about $2,600/kW and the remainder at a value of about $2,100-$2,300/kW. The total 40 MW/year PV deployment is based on the District's load growth projections on the distribution system and the calculations contained in the Utility Benefits Supporting Analysis section.

Figure 6-2 expands on Figure 6-1 by displaying the total value by Distribution Planning Area. Further, Figure 6-2 bounds the total value as a function of interconnection voltage. The value increases as the distributed PV is sited closer to customers at lower voltages.

6.2 PV Pioneers

Figure 6-3 presents the upper bound of the total "market potential" for PV Pioneer systems in the District's service area -- about 400 MW. See the Residential Rooftop PV Supporting Analysis section for details. The upper bound of 400 MW represents the total capacity of residential rooftop PV systems that could be deployed taking into account roof orientation, roofing material type, roof area, and shading. The results are shown by the District's distribution planning areas and by the federal tax bracket of the residents.

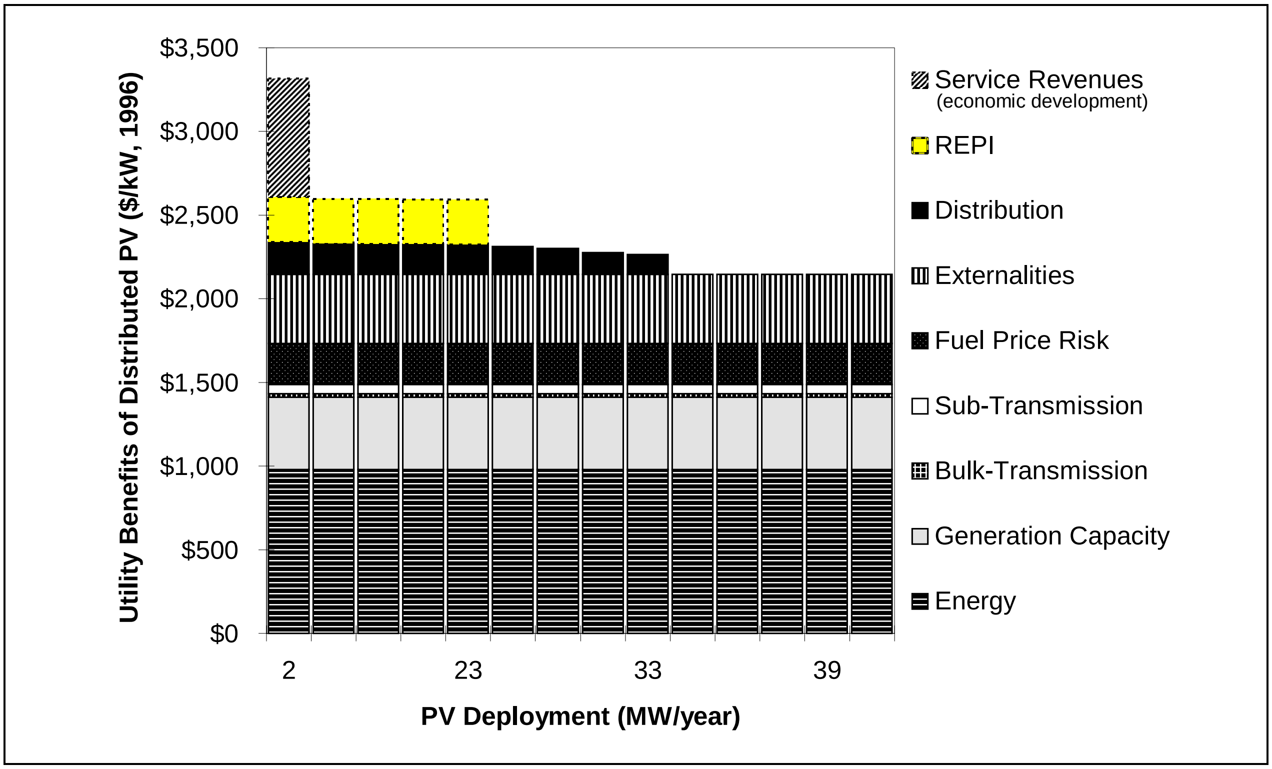


Figure 6-1. Marginal demand curve for tracking PV systems.

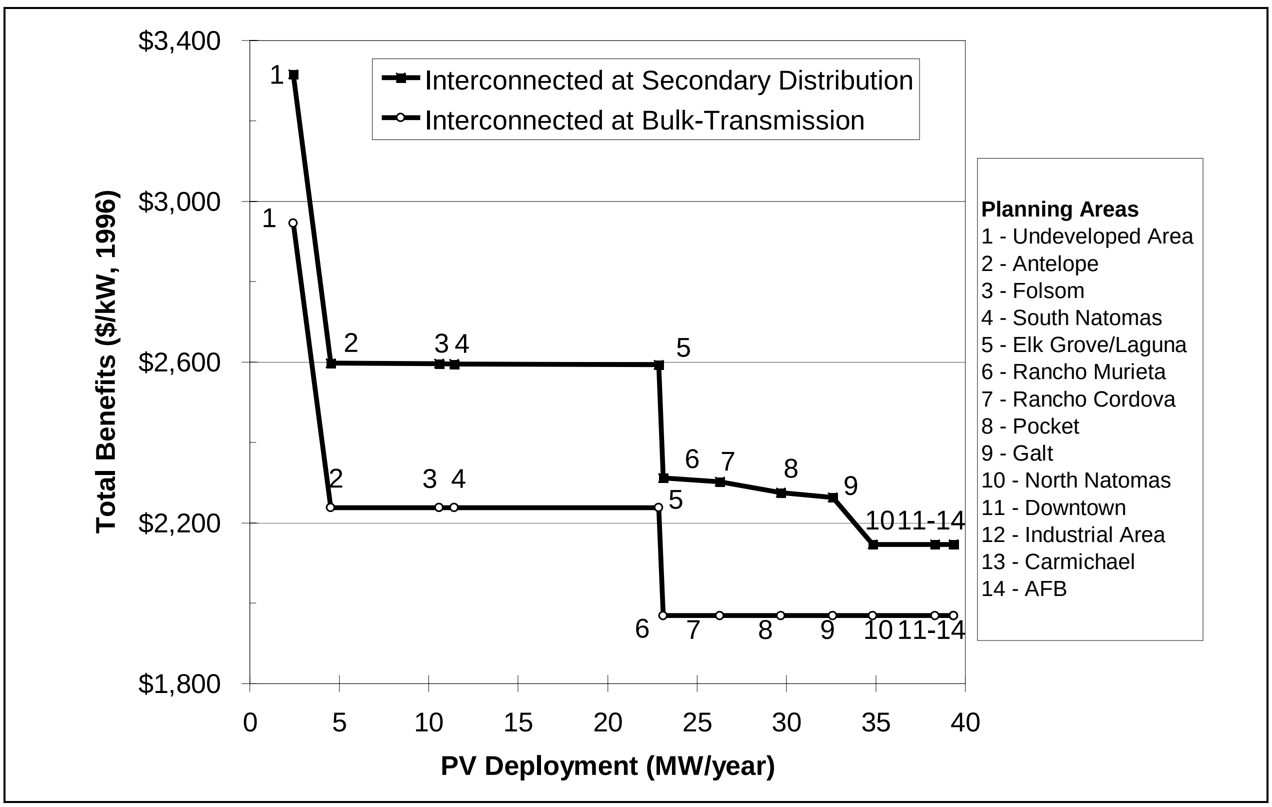


Figure 6-2. Total benefits for distribution planning areas & PV deployment.

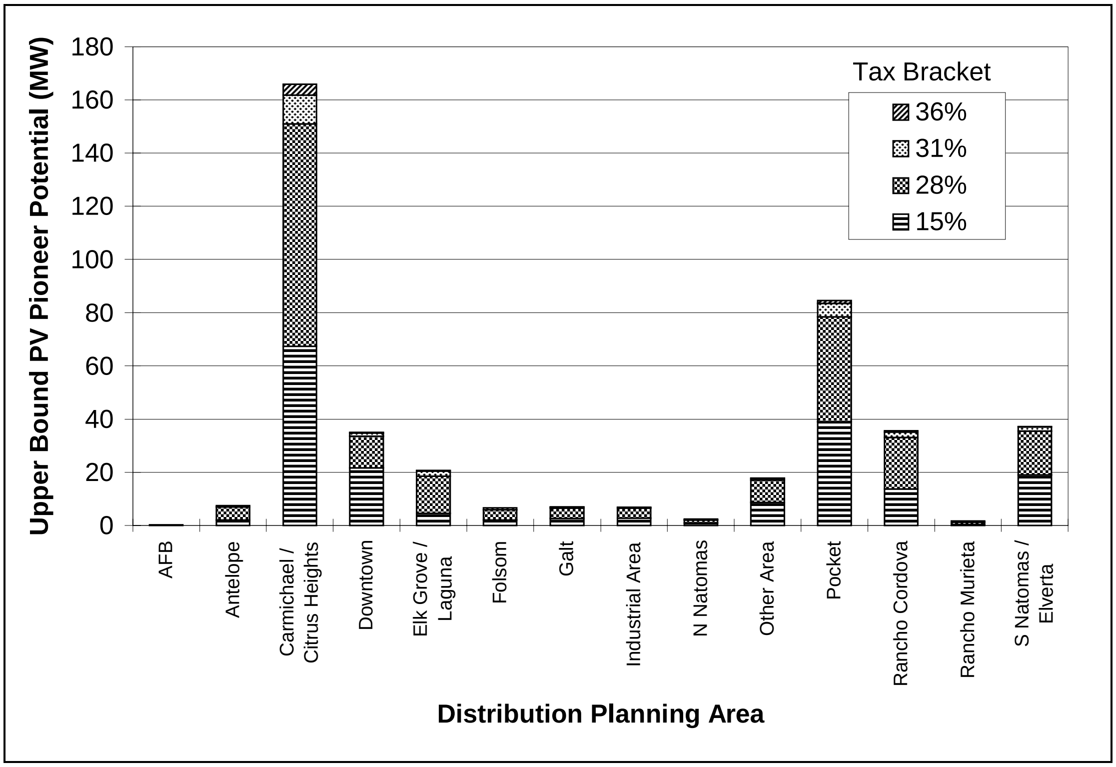


Figure 6-3. Upper bound res. PV Pioneer potential in 1996 (~ 400 MW).

6.3 Customer-Owned PV Systems

Figure 6-4 presents a gross estimate of the upper bound market for residential customer-owned PV systems. It simply takes the PV Pioneer market results and multiplies them by about 60%, the percentage of owner-occupied housing in the District. The total MW of capacity by tax bracket is also shown. An upper bound market demand curve is presented in Figure 6-5, which builds on the results from Figure 6-4. Table 6-1 lists the analysis assumptions. The figure shows the level of PV deployment as a function of PV price. The top curve is the market upper bound, assuming that each customer will break even on their investment. The lower curve assumes that of this upper bound market, about 1% of the population will purchase PV. The result is a market of about 30 MW of residential rooftop PV systems at prices between $2,500-$4,000/kW.

Again, *these are very gross estimates*, but they illustrate the rather large potential for customer-owned PV systems depending on PV system price and electricity rates. Ultimately, it is very difficult to speculate as to how many consumers would actually make a financial investment in PV, since economics is not the sole criterion by which people make purchase decisions. For example, customers would be far more willing to engage in a PV purchase if the District were somehow involved. Market research, such as focus groups and surveys, are required to better understand the customer-owned PV market. In any case, it is likely that as PV system prices approach $2,000/kW they will be deployed in much larger quantities by independent power developers and energy service companies.

Table 6-1. Residential Customer-Owned PV Economic Assumptions

Total market population	~ 225 MW
PV system size (power rating)	Even distribution between 0.5 and 4 kWac
Customer financing	7% interest, 30 year term, 10% down
PV system capacity factor	20% (system produces 7,000 kWh each year)
PV system life	30 years
Electricity rate	1996 District rates
Utility metering	Single net
Tax credits	none available
General inflation rate	3.6%
Electricity rate inflation	2.3%
Federal tax rates	36%, 31%,28%,15%
Market penetration rate	1%
Economic break-even point reached when net present value equals $0.00.	

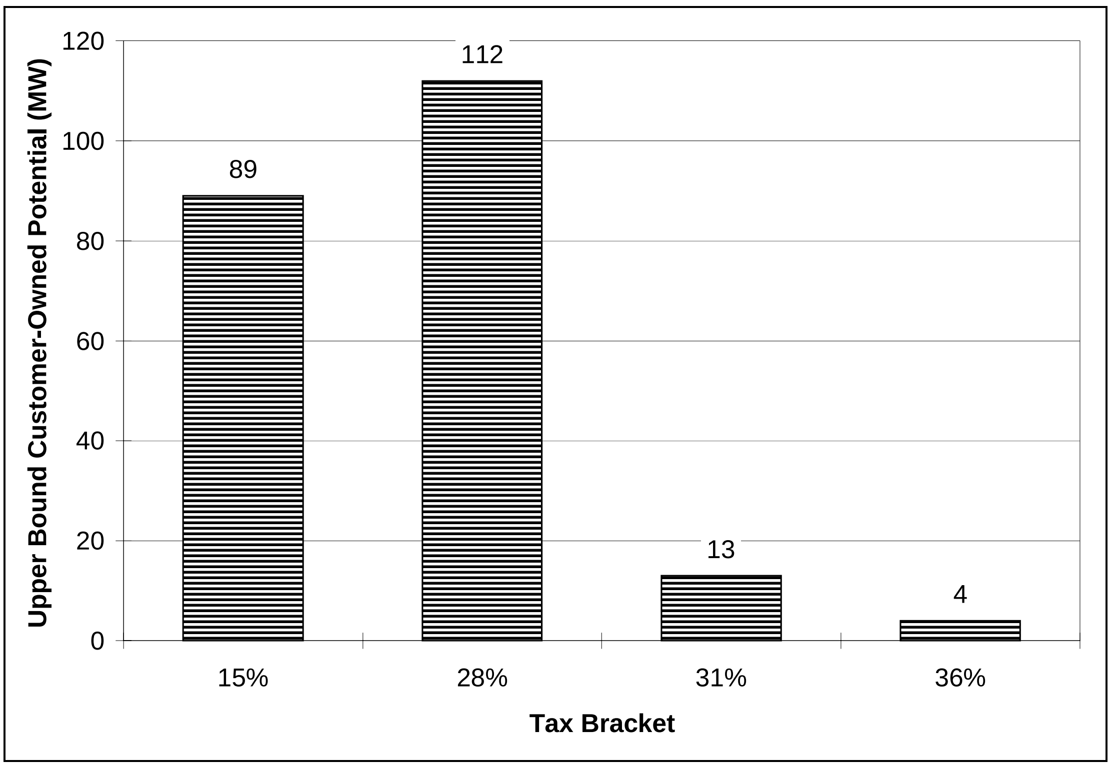


Figure 6-4. Upper bound res. customer-owned PV potential in '96 (~ 225 MW).

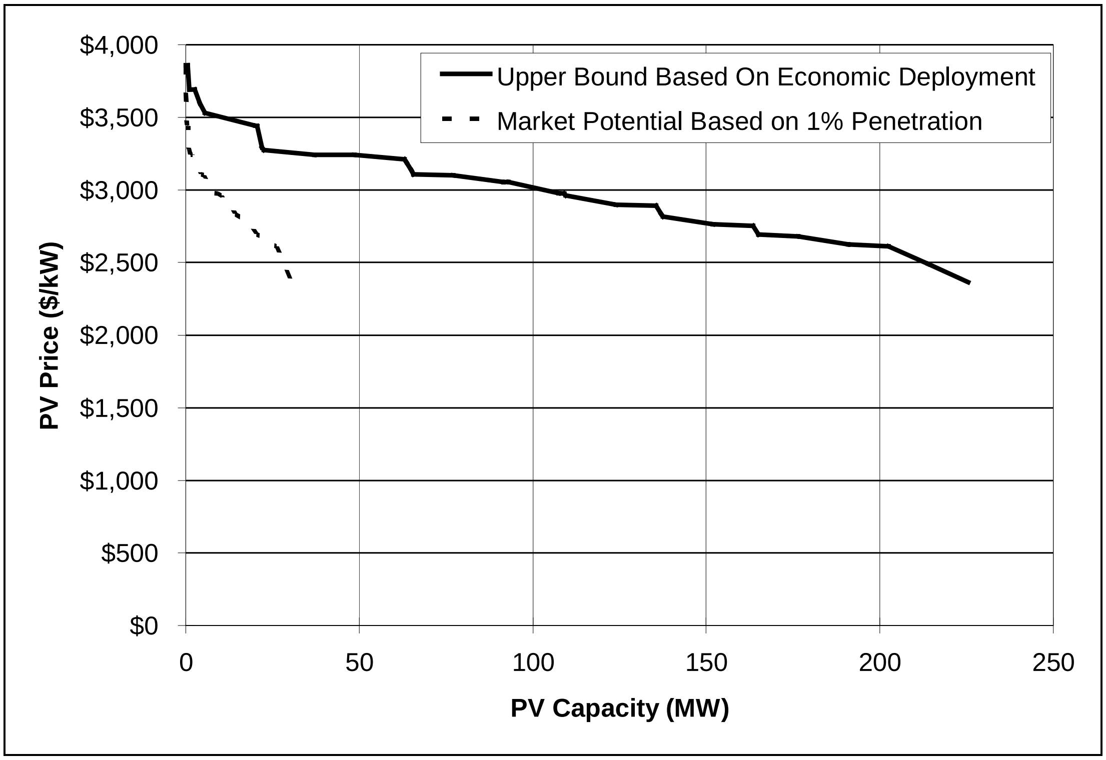


Figure 6-5. Customer-owned residential PV market in the District.

7. Net Metering Impacts

As of January 1, 1996 a new law requires all California utilities to develop a tariff to provide net metering of residential PV systems up to 10 kW in size. Two investor-owned utilities initially responded to the law by requesting Public Utilities Commission approval of net metering tariffs that included customer standby charges. Recently both of these utilities eliminated these standby charges because it was ruled that the charges would defeat the intent of the law which is to "encourage private investment in renewable energy resources, stimulate in-state economic growth, enhance the continued diversification of California's energy resource mix, and reduce utility interconnection and administrative costs".[28]

The law makes net metering available for each utility on a first-come first-served basis until the total PV capacity reaches 0.1% of the utility's 1996 peak demand. For the District, this translates to about 2.6 MW of PV. The law does not apply to the District's PV Pioneers because these are District-owned systems connected on the District's side of the customer revenue meter.

This section examines the economic impacts of net metering relative to dual metered PV systems. The impact of levying standby charges for net metered PV systems is also investigated.

7.1 Dual versus Net Metering

Figure 7-1 shows two metering arrangements for customer-owned residential PV systems. The PV system is connected on the customer's side of the meter for both metering arrangements. The customer captures the full retail price for all electricity that flows directly to meet the home's loads. The difference in the two metering schemes is the level of compensation for power that is in excess of the home's load and flows back to the utility grid.

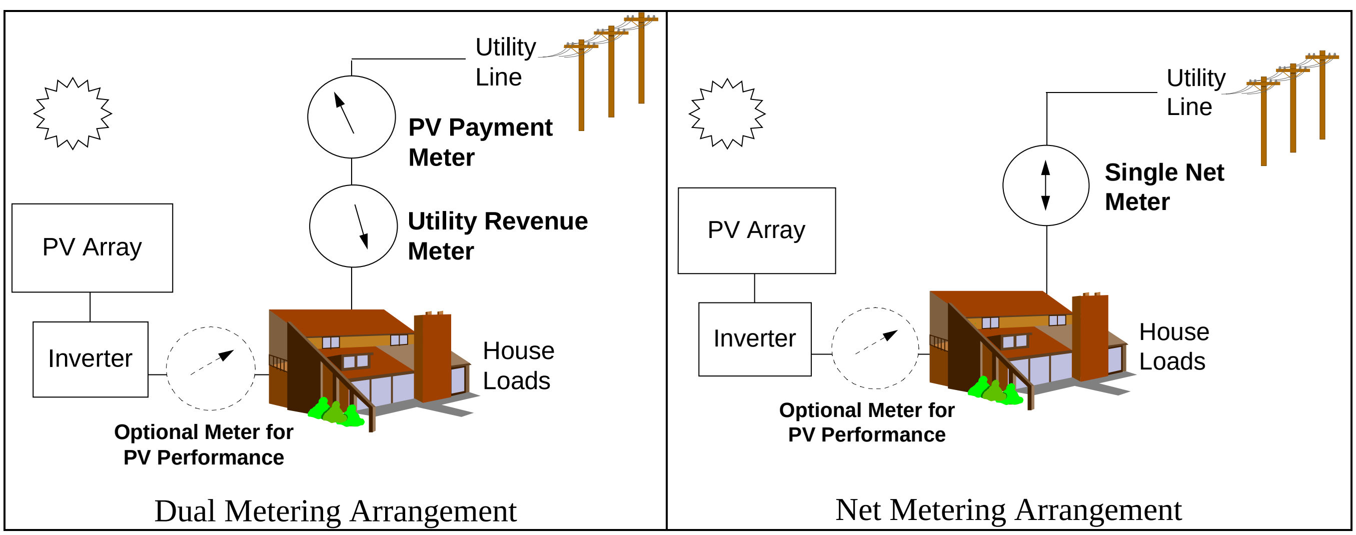


Figure 7-1. Metering arrangements for residential PV systems.

[28] California Public Utilities Code § 2827

Dual metering is the status quo and basis for comparing the impacts of net metering. In a dual metered arrangement, any PV generation that exceeds the customer's load is recorded by the PV payment meter as it flows to the utility grid. All of the electricity the customer purchases from the utility is recorded separately by the second meter, the revenue meter. The utility bills the customer at the end of the billing cycle, typically monthly, for all electricity consumed. Meanwhile, in a separate accounting transaction, the utility pays the customer for all electricity fed to the grid at the utility's avoided cost[29].

Net metering, alternatively, uses the existing standard customer meter to monitor the flow of electricity to and from the grid. The meter spins backward when the PV generation exceeds the home's load and flows to the utility grid. It spins forward when the customer's load is not being met in full with PV generation. At the end of the monthly billing period, the meter registers either net energy consumption or production. If the customer was a net consumer of electricity, they pay the bill at the regular retail rate. If the customer was a net producer for the billing cycle, then they are compensated at avoided cost. The key difference between dual and net metering is that the customer is credited at the retail rate for most of the electricity that is fed back to the utility.

Some utilities may prefer to use two meters and employ "net billing" instead of net metering using a single meter. Net billing yields the same financial results as a single net meter. The difference is that PV system output is measured by one meter and the customer's energy consumption by another. The net difference between the two readings is then calculated at the end of the billing cycle. This may be a preferred option since it provides accurate and separate readings of consumption and production, assuring the utility that meter tampering has not been committed and providing a way to determine if PV system maintenance is required.

7.2 Utility Bill Savings in the First Year

The district's Residential Service Rate Schedule R, as defined in part in Table 7-1, is used to calculate the utility bill savings for the different metering arrangements. Hourly District residential load data from 1994 and hourly expected PV system output from the same year are used as the basis for the calculations. The PV system is assumed to be south facing with a 20^{o} tilt angle and a 21.3% capacity factor. The total District residential load profile, divided by the total number of residential customers, is used as a proxy to represent an average residential customer.

Figure 7-2 and Figure 7-3 present the PV customer's utility bill savings for the first year for dual and net metered PV system ratings.[30] In addition, the financial impact of levying a standby fee of

[29] All calculations in this section assume an avoided cost rate of about $0.024/kWh. Utilities can credit customer's bills for the electricity supplied to the grid, however, most utilities have opted to send payment checks in a separate transaction.

[30] The results are highly dependent on the customer's actual load profile and quantity of consumption. Therefore, the results will vary significantly from one customer generator to the next. This is a reasonable proxy, however, when calculating the overall rate impacts of the net metering program and for getting an accurate sense of the relative differences between metering schemes.

$5.15/kW-month for net metered customers is evaluated. The following observations are made based on the results:

- Net metering provides almost no advantage to customers with PV system sizes less than 1 kW. This is because a very small amount of PV generation is fed to the grid. This point is illustrated in Figure 7-4, where PV output profiles for different capacity systems are overlaid onto the customer's load profile for a typical summer day. The 1-kW PV system output never exceeds the customer's load and therefore all of it is valued at the retail rate.[31]
- The larger the PV system, the greater the advantage net metering affords the customer. Net metering provides an 18% advantage over dual metering for a 2 kW PV system, 37% for a 3 kW PV system, and 44% for a 4 kW system. This is because a larger PV system capacity translates into more electricity fed to the utility grid. As a result, the average value of PV produced electricity declines as PV system size increases (see Figure 7-5).
- PV systems can significantly reduce customer loads and utility bills. The range of systems investigated, 0.5 to 4.0 kW, yield monthly bill savings of $8/month to $50/month translating into a reduction in the customer's total annual utility bill of 15% to 75%. These results show that customers do not financially bypass the District, even with a 4 kW PV system.[32]
- A standby fee of $5.15/kW-month would negate the savings gained from net metering. This result is independent of PV system size. Further, there may not be justification for standby fees. Assigning standby fees to small multiple PV generators is analogous to assigning standby fees to residential customers who purchase high efficiency air conditioning units.

Figure 7-6, Figure 7-7, Table 7-2, and Table 7-3 present additional net metering analysis results on a monthly basis.

---

[31] The dual metered savings may be somewhat overstated, however, since hourly average data are used in the analysis. Instantaneous data may reveal a larger amount of energy delivered to the grid. Nevertheless, this effect is probably small.

[32] The addition of storage would make bypass feasible. This may be considered impractical, however, for most home owners are not willing to make the significant lifestyle changes and financial investment that are required to go "off-grid".

Table 7-1. Residential Service Rate Schedule R[33]

	Winter (Nov-Apr)	Summer (May-Oct)
Tier I Baseline ($/kWh)	$0.07378	$0.08058
Tier II, >Baseline ($/kWh)	$0.11814	$0.12695
Baseline Quantities for Electric Space Heat (kWh)	1,120	700
Baseline Quantities for Non-Electric Space Heat (kWh)	620	700
Minimum customer charge	$3.50/month	

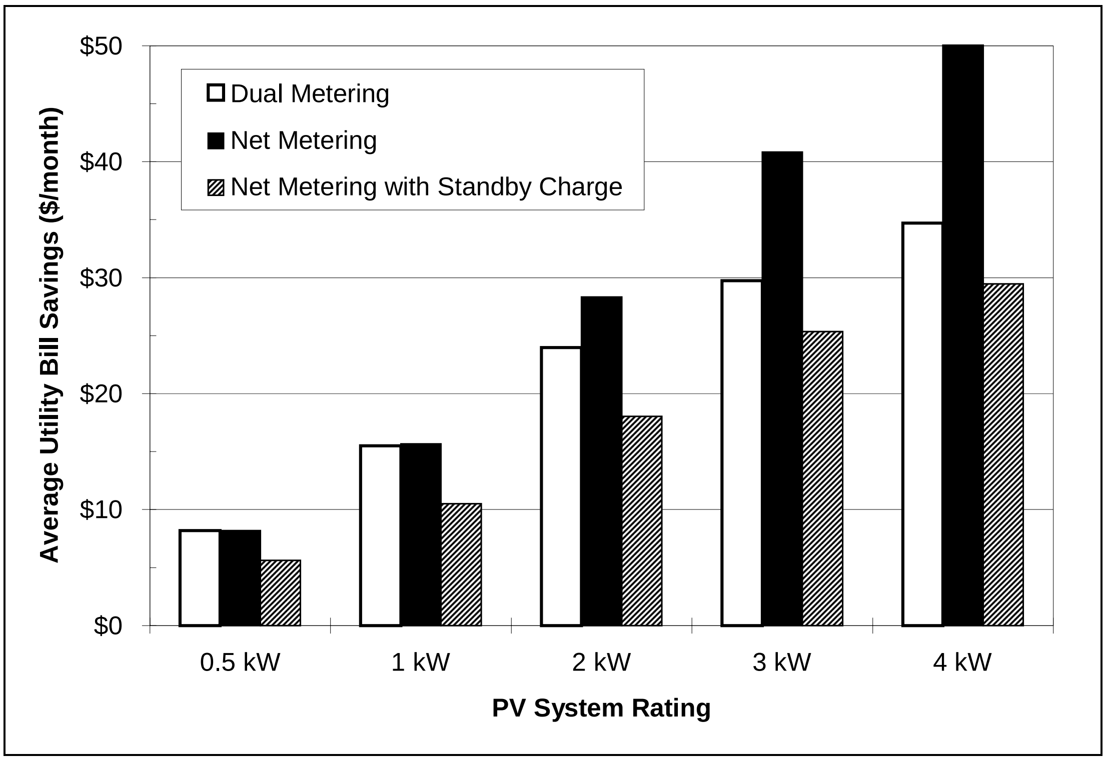


Figure 7-2. Utility bill savings in first year vs. metering scheme vs. PV size.

[33] Sacramento Municipal Utility District 1995 General Manager's Report and Recommendation on Miscellaneous Rate Issues, Amendment 1, October, 19, 1995 (published November 13, 1995).

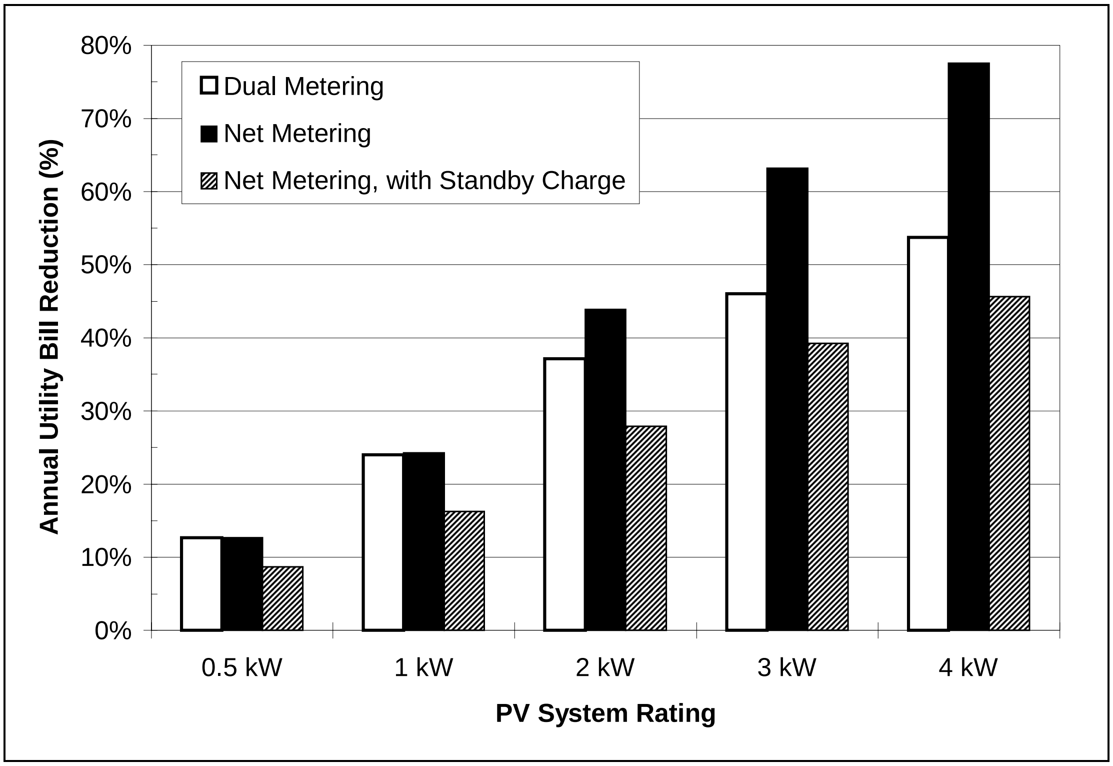


Figure 7-3. Utility bill savings in first year, in percent, for customers with PV.

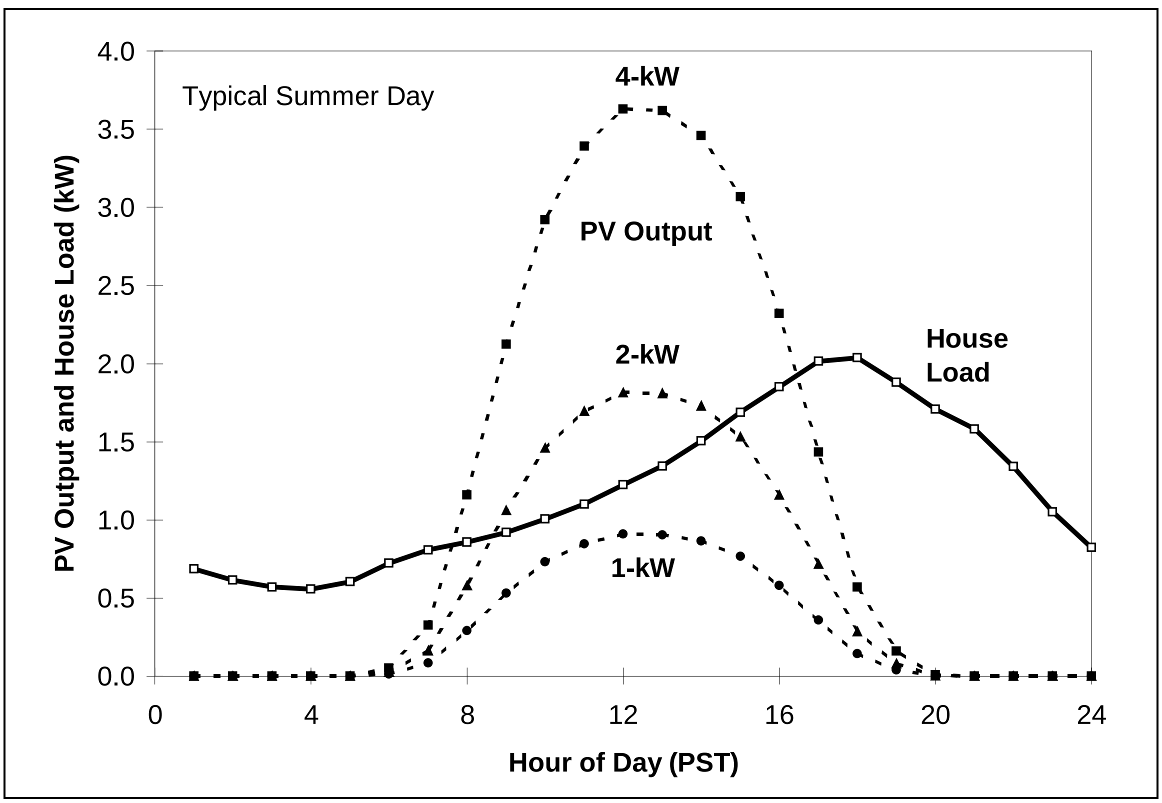


Figure 7-4. PV output profiles and house load for typical summer day.

Table 7-2. Dual Metering vs. Net Metering Statistics for First Year

	Customer with the Following PV System Size					
	No PV	0.5 kW	1.0 kW	2.0 kW	3.0 kW	4.0 kW
PV Production (kWh/year)	0.0	934	1,868	3,736	5,604	7,472
Net Energy Consumption (kWh/year)	9,175	8,241	7,307	5,439	3,571	1,703
Utility Bill for Dual Metering Customer ($/year)	$775	$677	$589	$487	$418	$359
Utility Bill for Net Metering Customer ($/year)	$775	$677	$587	$435	$285	$174
Value of PV Energy with Dual Metering ($/kWh)	$0	$0.105	$0.100	$0.077	$0.064	$0.056
Value of PV Energy with Net Metering ($/kWh)	$0	$0.105	$0.101	$0.091	$0.087	$0.080
Average Utility Bill Savings for Dual Metering Customer ($/month)	$0	$8	$15	$24	$30	$35
Average Utility Bill Savings for Net Metering Customer ($/month)	$0	$8	$16	$28	$41	$50
Average Utility Bill Savings for Net Metering Customer, with Standby Charge ($/month)	$0	$6	$11	$18	$25	$29

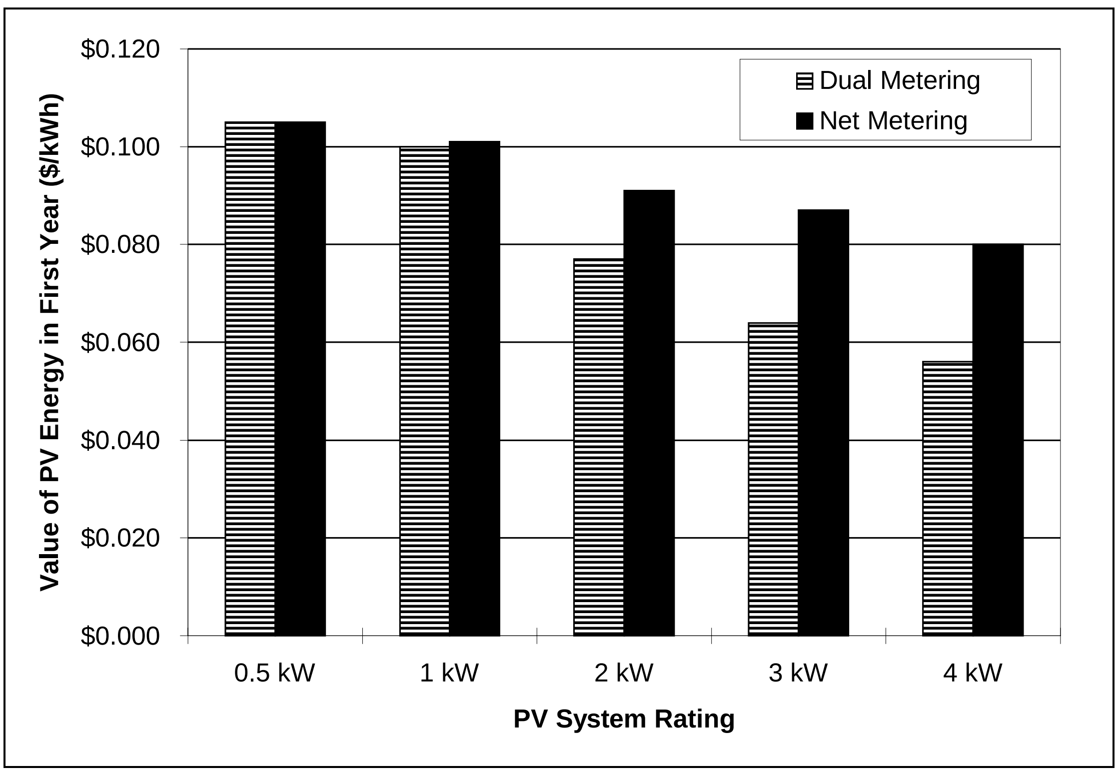


Figure 7-5. Average value of PV-produced electricity in first year.

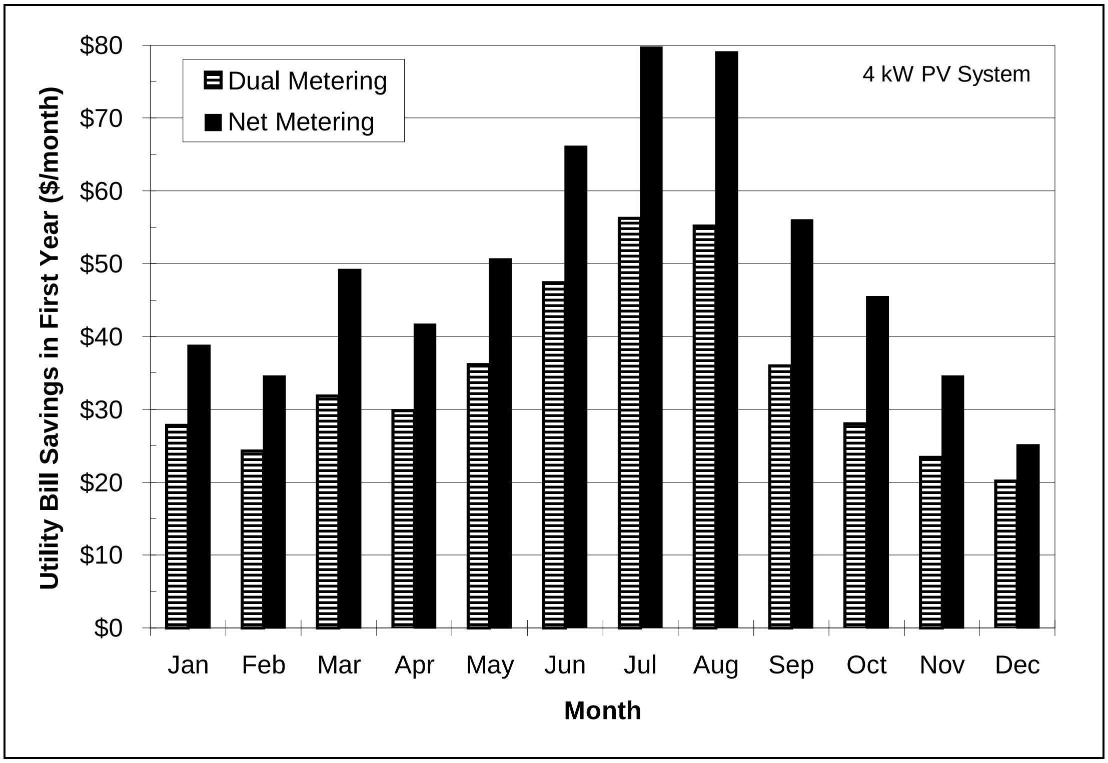


Figure 7-6. Monthly utility bill savings for a 4 kW PV system.

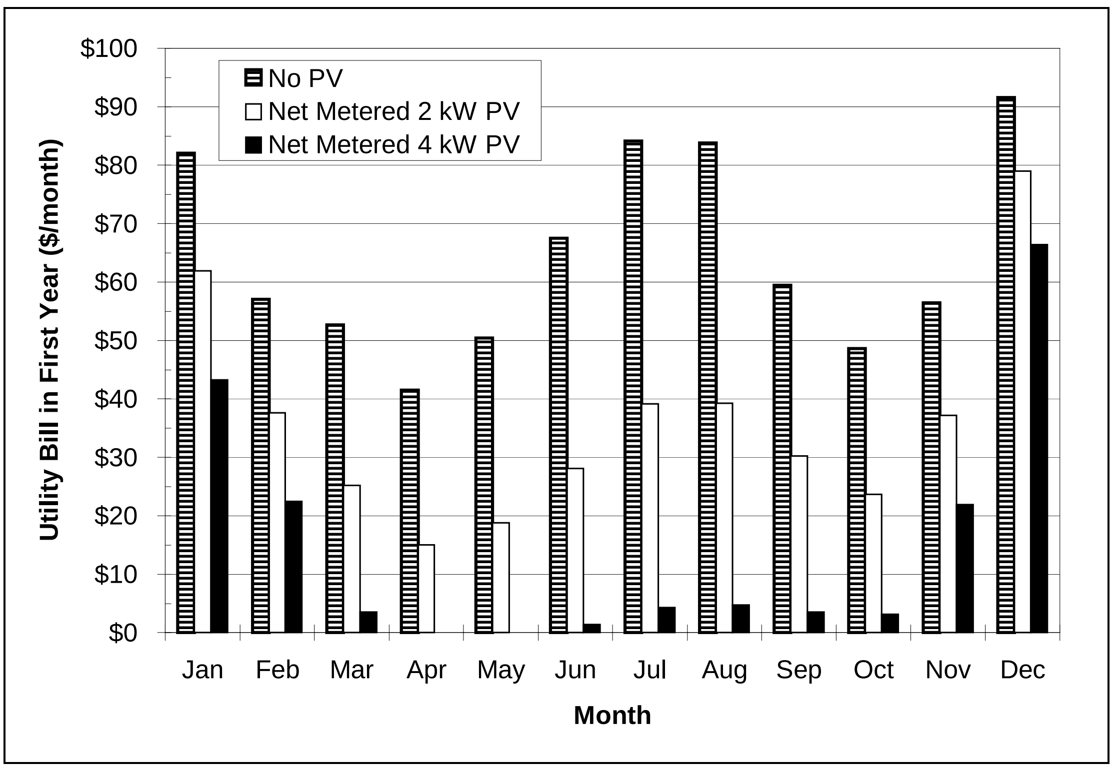


Figure 7-7. Monthly utility bill in first year for a customer with & without PV.

Table 7-3. Utility Bill of Customer With and Without PV, in First Year

	Customer with the Following PV System Size										
		0.5 kW		1 kW		2 kW		3 kW		4 kW	
	No PV	Dual Meter	Net Meter	Dual Meter	Net Meter	Dual Meter	Net Meter	Dual Meter	Net Meter	Dual Meter	Net Meter
Jan	$82	$77	$77	$72	$72	$63	$62	$58	$52	$54	$43
Feb	$57	$51	$51	$45	$45	$40	$38	$36	$30	$33	$22
Mar	$53	$44	$44	$38	$38	$31	$25	$26	$13	$21	$4
Apr	$42	$35	$35	$29	$28	$22	$15	$17	$4	$12	($0)
May	$50	$42	$42	$35	$35	$26	$19	$20	$4	$14	($0)
Jun	$67	$55	$55	$46	$46	$34	$28	$27	$10	$20	$1
Jul	$84	$70	$70	$57	$57	$43	$39	$35	$22	$28	$4
Aug	$84	$70	$70	$57	$57	$43	$39	$35	$22	$29	$5
Sep	$59	$51	$51	$44	$44	$35	$30	$29	$16	$24	$4
Oct	$49	$42	$42	$36	$36	$30	$24	$25	$11	$21	$3
Nov	$56	$50	$50	$45	$45	$40	$37	$36	$30	$33	$22
Dec	$92	$88	$88	$85	$85	$79	$79	$75	$73	$71	$66
TOTAL	**$775**	**$677**	**$677**	**$589**	**$587**	**$487**	**$435**	**$418**	**$285**	**$359**	**$174**

7.3 Net Metering vs. Time-of-Use Rates

The District's Residential Service Rate Schedule R, with optional Time-of-Use- Periods (TOU), is used to calculate the utility bill savings for customers with PV (see Table 7-4). It is assumed the PV system is dual metered and any PV power delivered to the grid is compensated at avoided cost.

Table 7-5 shows that an average residential customer on a TOU schedule will have about the same bill as a non-TOU customer (the average TOU customer saves about 1.5% on their annual bill, or $10/year). *A TOU customer with a PV system that is dual metered will actually have less bill savings than if they remained on a non-TOU schedule with dual metering.* This is because only about 20% of the annual PV generation occurs during the District's designated on-peak periods. It is also worth noting that the District has significantly lower TOU rates than California IOUs such as PG&E. PG&E on-peak TOU rates are about $0.32/kWh and off-peak about $0.08/kWh[34].

[34] Pacific Gas & Electric Company Rate Finder, January 1, 1996.

Table 7-4. Residential Service Rate Schedule R, with Time-Of-Use Periods

	Winter (Nov-Apr)	Summer (May-Oct)
On Peak ($/kWh)	$0.16459	$0.16459
Off Peak ($/kWh)	$0.05964	$0.05964
Minimum customer charge	$5.00/month	

Baseline quantities do not apply. On-peak hours (PDT): Winter (weekdays, 7:00-10:00 a.m. and 5:00-8:00 p.m.); Summer (weekdays, 1:00-8:00 p.m.). Off-peak hours: All day weekends and 11 holidays, New Years Day, Martin Luther King Jr.'s Birthday, Lincoln's Birthday, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving, Christmas Day, and all other hours not defined as on-peak.

Table 7-5. Utility Bill With and Without PV, in First Year

	Customer with the Following PV System Size					
Month	**No PV**	**0.5 kW**	**1 kW**	**2 kW**	**3 kW**	**4 kW**
Jan	$75	$72	$69	$64	$60	$57
Feb	$58	$55	$51	$46	$41	$37
Mar	$57	$50	$44	$36	$30	$25
Apr	$45	$38	$32	$24	$18	$13
May	$50	$42	$34	$24	$17	$11
Jun	$69	$59	$50	$36	$27	$19
Jul	$80	$70	$61	$46	$35	$27
Aug	$82	$72	$62	$47	$37	$29
Sep	$62	$54	$47	$36	$29	$23
Oct	$46	$40	$34	$27	$22	$18
Nov	$58	$54	$50	$44	$40	$37
Dec	$83	$81	$79	$75	$72	$70
TOTAL	$765	$688	$613	$505	$430	$367

Table 7-6. Utility Bill Savings with TOU, in First Year

	Customer with the Following PV System Size					
	No PV	**0.5 kW**	**1 kW**	**2 kW**	**3 kW**	**4 kW**
Average Utility Bill Savings ($/month)	$0	$6	$13	$22	$28	$33
Average Utility Bill Savings	$0	$77	$152	$260	$335	$398

($/year)						

7.4 Revenue and Rate Impacts of the California Net Metering Law

A present value analysis was conducted to gain a better understanding of the revenue and rate impacts of the net metering law SB656 on the District. Table 7-7 shows the assumptions used to conduct the analysis. The results represent the difference between the revenue and rate impacts of dual metered and net metered PV systems. Three cases were evaluated to bound the problem:

- The Upper Bound is very aggressive in terms of PV system size and the number of years to reach the program cap of 2.6 MW. It assumes that residential customers will purchase and install 130 4-kW PV systems each year over the next five years -- about the same pace as the District's PV Pioneer program. Also, it is assumed that the District will pay additional metering costs of $340 per installation ($170/meter) to install bi-directional meters so the District can monitor electricity consumed and produced by the customer and to provide further incentives to customers to purchase and install PV systems. Finally, the Upper Bound assumes no administrative, accounting, or meter reading savings. The Upper Bound will have the largest revenue and rate impacts on the District.
- The Base Case assumes an average of 130 2-kW PV systems will be installed each year over the next 15 years to reach the program cap. The smaller system size reflects a lower level of investment by customers who own their PV systems. It is recognized that once a significant number of PV systems are installed, the District will have to implement changes to its computer billing program OSCAR at a cost of about $100,000. A moderate amount of meter reading, and billing cost savings are included as benefits to the District.
- The Lower Bound assumes an average of 52 2-kW PV systems are installed each year over the next 25 years to reach the program cap of 2.6 MW. It is assumed that the District opts to allow the existing meter to spin backwards and eliminate the added cost of purchasing and installing a second meter. Additional savings accrue to the District including interconnection, administration, meter reading, and billing costs savings.

7.4.1 Revenue Impacts

Figure 7-8 shows the revenue impact of net metering from the perspective of the District and its PV customers. The revenue impact has been levelized to show the financial impact each year. The District's customers who own their own PV systems stand to gain between $50,000 and $170,000 per year as a result of the net metering law. The revenue impacts to the District range between a levelized loss of $185,000/year to a gain of about $30,000/year. The Base Case scenarios show that PV customers will gain about $70,000/year compared with a gain of almost $10,000/year to the District. Table 7-8 shows that the gain to the District comes from cost savings that result from meter reading and bill paying efficiencies. These are the savings that accrue to the District if an equal number of PV systems were dual metered and the District treated these as independent power producers.

What the revenue impacts will actually be, and the assumptions used in this analysis, can be debated. The Upper Bound and Lower Bound scenarios, however, were constructed to provide the conceivable range of financial impacts on the District and its customers who own PV systems. The Upper Bound scenario, from the District's perspective, is the worst case because it results in the largest loss in revenue. On a present value basis, this is about $2.3 million in 1996 dollars (see Table 7-9). This scenario assumes that 650 4-kW PV systems would be installed in the next 5 years. Further, it is assumed the District will not gain any financial cost savings, but in fact have to spend additional revenue to upgrade the computer billing system. The rate impacts of the net metering legislation are discussed below.

7.4.2 Rate Impacts

Assuming the Upper Bound case, which is the worst case from the District's perspective, rates would have to be increased by about 0.0009% or nine thousandths of 1 percent. A residential customer with a blended average rate of $0.0845/kWh would have to pay $0.084508/kWh. This translates to an increase of about 3 cents/month on the average residential customer's electric bill. The Base Case and the Lower Bound case would actually decrease rates, and customer bills, a very small amount. No matter which case is assumed, the impact of the net metering law on the District's rates is negligible.

Table 7-7. Net Metering Analysis Assumptions

	Cases Evaluated		
	Upper Bound	**Base Case**	**Lower Bound**
Program Cap (MW)	2.6	2.6	2.6
Average PV System Size (kW)	4	2	2
Years to reach program cap	5	10	25
PV System Life (years)	30	30	30
Average Number of PV Systems Installed per Year	130	130	52
Total Number of Systems Installed for Program	650	1300	1300
Avoided Meter Hardware Costs ($/system)	-340	-170	100
Avoided Interconnect Labor (hours/system)	0	0	1
PV to Grid Factor (% of energy that flows to grid)	54	25	25
Blended Retail Electric Rate ($/kWh)	0.0845	0.0845	0.0845
Effective PV Payment for Net Metered PV ($/kWh)	0.0803	0.0910	0.0910
Utility Avoided Generation Cost ($/kWh)	0.0238	0.0238	0.0238
Avoided Meter Reading/Bill Processing (minutes/system-month)	0	8	8
Utility Labor Rate, fully burdened ($/hr)	35	35	35
PV Capacity Factor	0.203	0.203	0.203
General Inflation	0.036	0.036	0.036
Electric Rate Inflation	0.023	0.023	0.023
Discount Rate	0.066	0.066	0.066

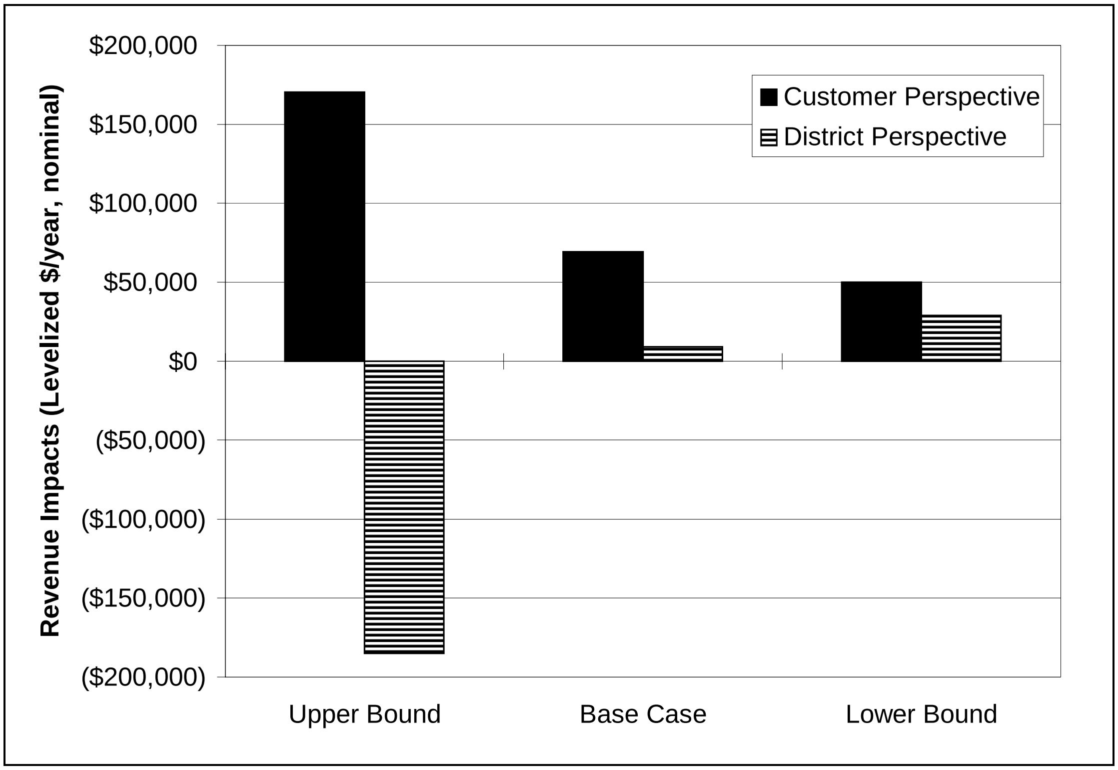


Figure 7-8. Revenue impact of net metering law (levelized $/year, nominal).

Table 7-8. Revenue Impact of Net Metering Law (Levelized, $/year, nominal)

	Upper Bound		Base Case		Lower Bound	
	Customer Perspective	**District Perspective**	**Customer Perspective**	**District Perspective**	**Customer Perspective**	**District Perspective**
Electric bill revenue saved (lost)	$170,385	($170,385)	$69,278	($69,278)	$49,954	($49,954)
Avoided meter hardware & interconnection costs	n/a	($14,480)	n/a	($13,089)	n/a	$8,120
Avoided meter reading & billing costs	n/a	$0	n/a	$91,299	n/a	$70,822
Net Impact	**$170,385**	**($184,866)**	**$69,278**	**$8.932**	**$49,954**	**$29,048**

Table 7-9. Revenue Impact of Net Metering Law (Present Value, 1996$)

	Upper Bound		Base Case		Lower Bound	
	Customer Perspective	District Perspective	Customer Perspective	District Perspective	Customer Perspective	District Perspective
Electric bill revenue saved (lost)	$2,305,930	($2,305,930)	$968,245	($968,245)	$734,366	($734,366)
Avoided meter hardware & interconnection costs	n/a	($195,972)	n/a	($182,939)	n/a	$119,375
Avoided meter reading & billing costs	n/a	$0	n/a	$1,276,013	n/a	$1,042,024
Net Impact	**$2,305,930**	**($2,501,902)**	**$968,245**	**$124,830**	**$734,366**	**$427,034**

8. Utility Benefits Supporting Analysis

This section provides the supporting analysis for the detailed calculation of utility benefits presented in the Utility Benefits section. A subsection is devoted to each of the utility benefits evaluated. See the Utility Benefits section for a presentation of the simplified QuickScreen results and how they compare with those obtained using the detailed approach.

The energy, capacity, externality, and T&D benefits were calculated using data from the District's 1995 Marginal Cost Study. These benefits must be revisited once the District completes a new study that considers electric industry restructuring impacts on marginal costs.

8.1 ENERGY BENEFITS

The District has developed 20-year forecasts of the cost of delivering an incremental amount of energy to the grid, otherwise known as marginal energy costs. These cost projections are driven by natural gas price forecasts. Marginal energy costs vary by time period and by interconnection voltage because of electric losses.[35] Table 8-1 presents, for example, 1996 and 30-year levelized marginal energy costs for a customer or a resource connected at the primary distribution level (SMUD 1995i). These are solely District costs to obtain an incremental amount of energy.

Table 8-1. Marginal Energy Costs at Primary Distribution Level ($/kWh, $1996)[36]

	Summer			Winter		Spring	Annual
	Super Peak	Peak	Off-Peak	Peak	Off-Peak		
1996	0.0287	0.0232	0.0205	0.0299	0.0213	0.0213	0.0236
30-year, levelized	0.0416	0.0373	0.0332	0.0409	0.0350	0.0304	0.0348

Time Periods: <u>Summer Super Peak</u> (July & August/weekdays/1300-2100); <u>Summer Peak</u> (September/weekdays/1300-2100; July & August/weekends/1300-2100; July & August/weekdays/0700-1300 & 2100-2300); <u>Summer Off Peak</u> (June-September/all other hours); <u>Winter Peak</u> (October-February/weekdays/0700-2200); <u>Winter Off Peak</u> (October-February/all other hours); and <u>Spring</u> (March-May/all hours).

8.1.1 Energy Benefits Analysis

The first step to calculate the energy benefits is to determine the PV output by time-of-use period. Figure 8-1 and Figure 8-2 present the PV output by time period for tracking and fixed systems, respectively. The two system configurations yield very similar output allocations by time-of-use period. The tracking system produces a slightly greater share of production during the summer peak while the fixed system produces a greater share during the winter peak.

35 See Electric Loss subsection.

36 Including electric losses.

Combining the marginal energy costs and output by time-of-use period yields the total energy benefit of PV production.[37] In the end, the total energy benefit of a distributed PV system is driven by its total annual energy output or annual capacity factor. Table 8-2 presents expected distributed PV system annual capacity factors for the years 1993-1995 and for an "average year" based on average weather data. These values are what we expect these systems to produce based on the PVGRID™ computer simulation program, taking into account various expected losses such as inverter efficiency, shadowing, soiling, and downtime. The average year output is used to determine the energy value since it represents long-term average PV system performance. The capacity factors for the specific years 1993-1995 are provided for comparison purposes as an indication of how PV system performance varies from one year to the next.

Based on average year output, about a 20% advantage is expected for tracking PV systems at substations over fixed systems on residential rooftops. See the PV System Ratings and Performance section for additional energy calculations and results.

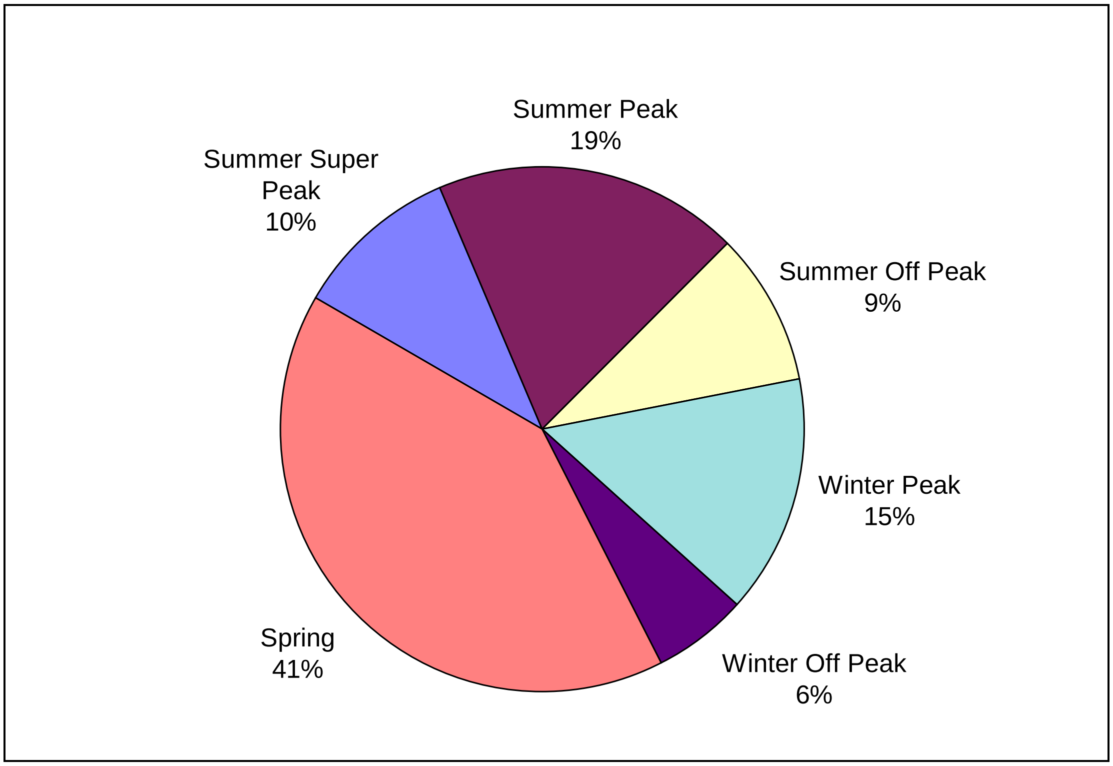


Figure 8-1. Tracking PV system output by TOU period (% of annual output).

[37] Note that combining average annual output and average marginal energy costs yield almost identical energy benefit results when combining time-of-use output and time-of-use marginal energy costs.

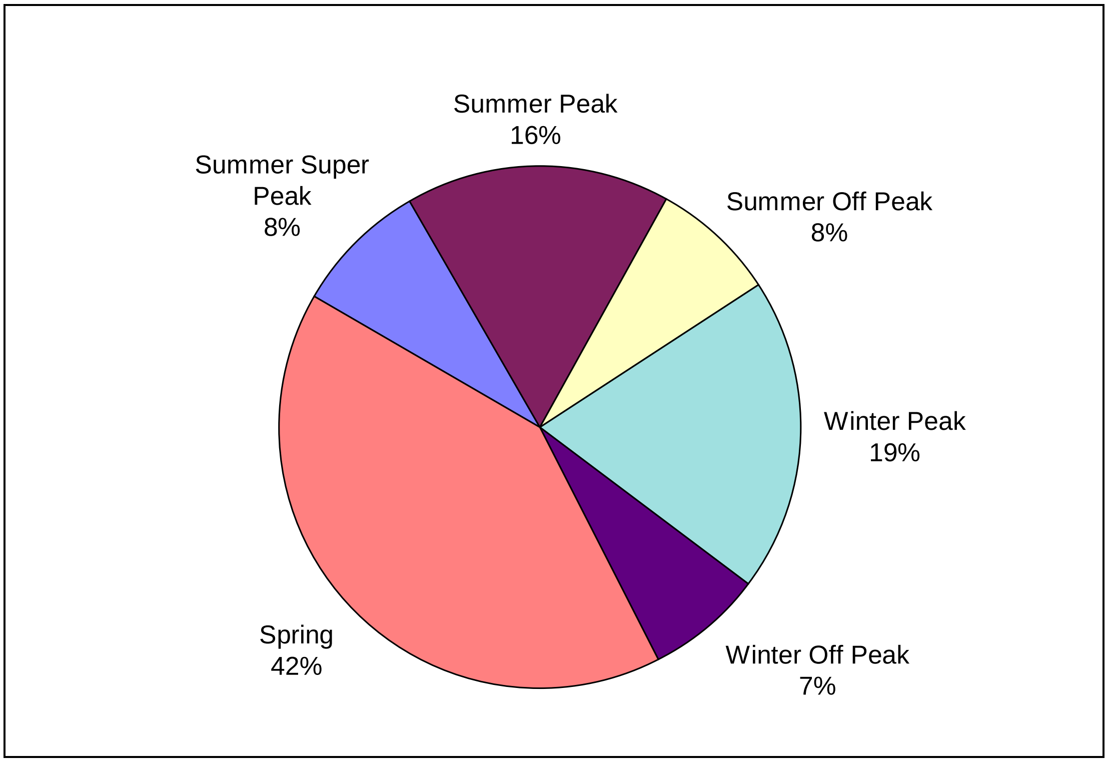


Figure 8-2. Fixed PV system output by TOU period (% of annual output).

Table 8-2. Expected PV System Capacity Factors (%)[38]

	1993	1994	1995	Average Year
Fixed Residential Rooftop	20.5	21.3	19.9	20.5
Tracker @ Hedge Substation	24.3	26.4	24.9	24.7

8.1.2 Energy Benefits: Economic Results

The energy benefits results are presented in Table 8-3. A tracking grid-support system interconnected at primary distribution yields a total energy benefit of $974/kW, present valued in 1996 dollars. This is 21% greater than the $805/kW energy benefit of a fixed residential rooftop system at secondary distribution. These results are based on average year capacity factors of 24.7% and 20.3% for tracking and fixed PV systems, respectively, yielding a 30-year levelized energy value of $0.035/kWh.[39]

[38] Based on PVGRID™ simulations and NREL Typical Meteorological Year (TMY2) hourly data for average year performance and actual measured weather data at Davis, CA for 1994 and 1995. Annual PV System Capacity Factor = Annual Energy Production (kWh) / [PV System Rating (kWac) x 8,760 hours/year]

[39] A fixed system capacity factor of 20.3% is used since this represents the expected "composite" PV Pioneer capacity factor, discussed in further detail below.

Table 8-3. Energy Benefits of Distributed PV Systems ($1996).

	Energy Benefit	
	Present Value ($/kW)	Levelized 30-year ($/kWh)
Tracking PV System (at primary distribution)	974	0.035
Fixed PV System (at secondary distribution)	805	0.035

8.2 CAPACITY BENEFITS

The District has developed 20-year forecasts of the cost of obtaining an incremental amount of systemwide generation capacity referred to as marginal capacity costs. These cost projections reflect forecasts of capacity surplus and shortages and are driven by meeting reliability criteria, such as loss-of-load-probability (LOLP)[40], and the cost of adding system capacity. After the year 2000, the District uses the estimated cost of a gas combustion turbine as the proxy for capacity additions.

As with marginal energy costs, marginal capacity costs vary by time period and by interconnection voltage because of electric losses. Table 8-4 presents, for example, 1996-2000 and 30-year levelized marginal capacity costs, with outages, for a customer or a resource connected at the primary distribution level (SMUD 1995i). The value of added capacity fluctuates significantly as the need for capacity changes from year to year.

Table 8-4. Marginal Capacity Costs at Primary Distribution ($/kW-yr, $1996)[41]

	Summer		Annual
	Super Peak	Peak	
1996	1.7	0.0	1.7
1997	16.2	9.6	25.8
1998	6.7	0.0	6.7
1999	0.2	0.0	0.2
2000	26.1	15.5	41.6
30-year, levelized	29.0	16.7	45.7

Time Periods: Summer Super Peak (July & August, weekdays 1300-2100); Summer Peak (June & September, weekdays, 1300-2100; July & August, weekends, 1300-2100; July & August, weekdays, 0700-1300 & 2100-2300)

8.2.1 Capacity Credit Formulation

The resource's "capacity credit" (also referred to as "effective load carrying capability" or "ELCC") is the degree to which the addition of that resource lowers the utility's overall peak capacity need. A resource that is fully dispatchable is assigned a capacity credit of 100%. Distributed PV will have a capacity credit of less than 100% since it is defined as a non-dispatchable resource in this study.

---

[40] One utility industry planning standard to ensure long-term reliability against bulk power outages is the 1-day-in-10-years LOLP. LOLP is the estimated amount of time that the utility's installed generation capacity will not be able to meet all customer load. The 1-day-in-10-years criterion translates into a capacity shortfall of not meeting demand for 2.4 hours in one year or one day in 3,650 days, depending on whether hourly or daily peak load is used in the LOLP calculations.

[41] Including electric losses.

The capacity credit was calculated for SMUD fixed and tracking PV systems. An LOLP formulation is used, whereby it is determined how much additional load can be added to the system with the PV resource until the LOLP returns to the same value without the PV resource. An LOLP approach is one of a variety of ways to calculate a resource's capacity credit and this approach differs from "a more sophisticated system approach" employed by the District which captures interaction with other resources (Jones 1996). The capacity credit using an LOLP approach is approximated with the following equation (Garver 1966, Hoff 1987):

$$\text{Capacity Credit} \approx \left\langle (m)\ln\left\{ \frac{\sum_{i=1}^{8760} e^{\left[\frac{-\left(L_{peak} - L_i\right)}{m}\right]}}{\sum_{i=1}^{8760} e^{\left[\frac{-\left(L_{peak} - \left(L_i - PV_i\right)\right)}{m}\right]}} \right\} \right\rangle \div \text{Plant Rating}$$

One year of measured hourly District system load data and estimated hourly PV output data for 1994 were used to calculate the capacity credit. L_{peak} is the system peak load for the entire year, in this case 2,044 MW in 1994. L_i is the system load for hour i, in MW. PV_i is the PV plant output for hour i, in MW. Finally, m is the Garver Characteristic which is assigned a value of 5% of the District's peak system load, or about 100 MW. It is defined as the inverse slope of the ln(LOLP).

8.2.2 Capacity Credit Results

The capacity credit for the tracking PV system was calculated at 73%, while a 53% capacity credit was calculated for fixed rooftop PV systems. Tracking allows PV systems to generate more electricity in the late afternoon when the District's peak load occurs, during 5:00-6:00 pm Pacific Daylight Time. Figure 8-3 illustrates this point by showing the normalized system load and PV output profiles for July 14, 1994, the day of the system peak. During the peak load hour, the tracker is putting out 80% of its rating while the fixed PV system is generating about 50% of its rated power. The "fixed" PV system is actually an estimated composite of residential PV Pioneer systems, as discussed in the next subsection.

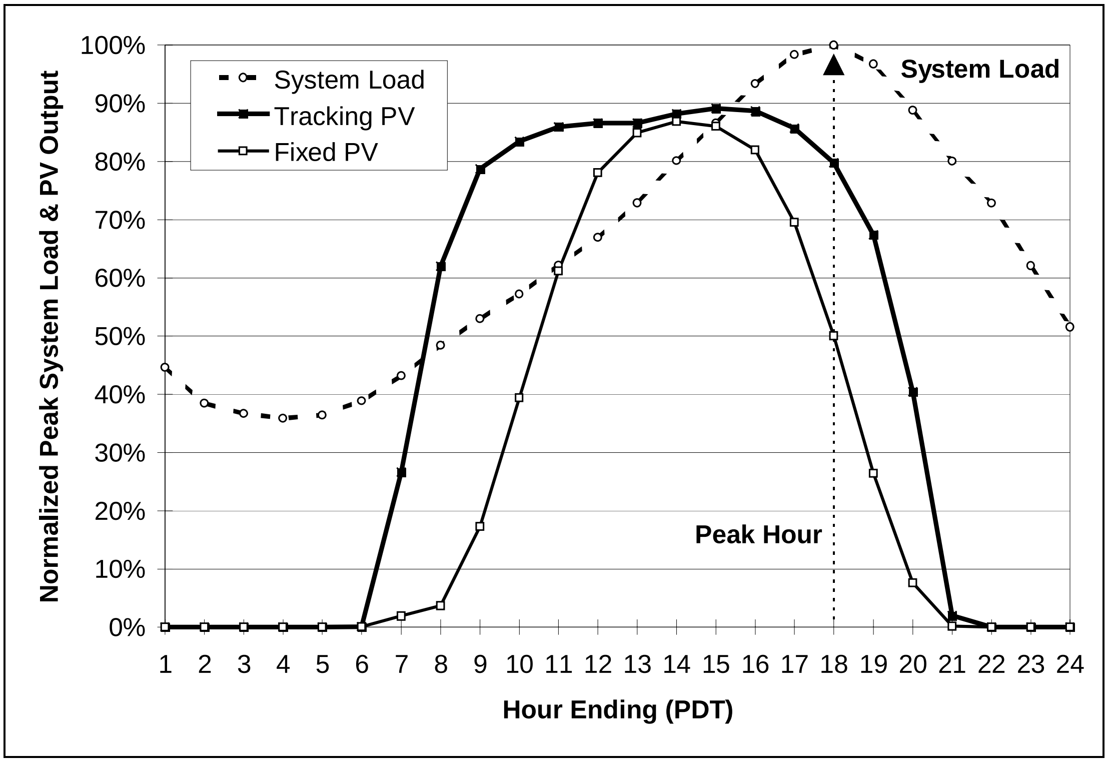


Figure 8-3. System load and PV output profiles on peak day, July 14, 1994.

These high capacity credits are achieved because of the strong correlation between the available solar resource and peak loads. Sacramento peak loads are driven by air conditioning demand which, in turn, is driven by the intensity of the sun and subsequently ambient temperature. The bottom line is that there is typically an excellent solar resource available during heat storms and during the District's peak loads.

Figure 8-4 presents the District's normalized system load for the top 25 hours in 1994.[42] The corresponding PV system output during these crucial peak loads, as a percentage of PV system rating, is consistently high -- between 70% and 100%. Figure 8-5 further demonstrates the correlation between peak load and solar resource/PV output. The profiles for the top 5 load system load days (June 10, July 13 & 14, and August 15 & 16) are plotted against tracking PV system output for these same five days. Consistent load and PV output patterns emerge. On one day and on one hour, passing clouds cause a 20% dip in PV output. Otherwise, PV output and load are very predictable.

[42] The top 25 load hours occurred during 10 summer peak days in 1994: June 10 & 27; July 8, 12, 13, 14 & 27; and August 15, 16, & 17. The distribution of these peak hours is as follows: 1 peak occurring during the hour ending 4:00 pm, 8 occurrences for the hour ending 5:00 pm, 11 occurrences for the hour ending 6:00 pm, and 5 occurrences for the hour ending 7:00 pm. All times in Pacific Daylight, or Daylight Savings, Time.

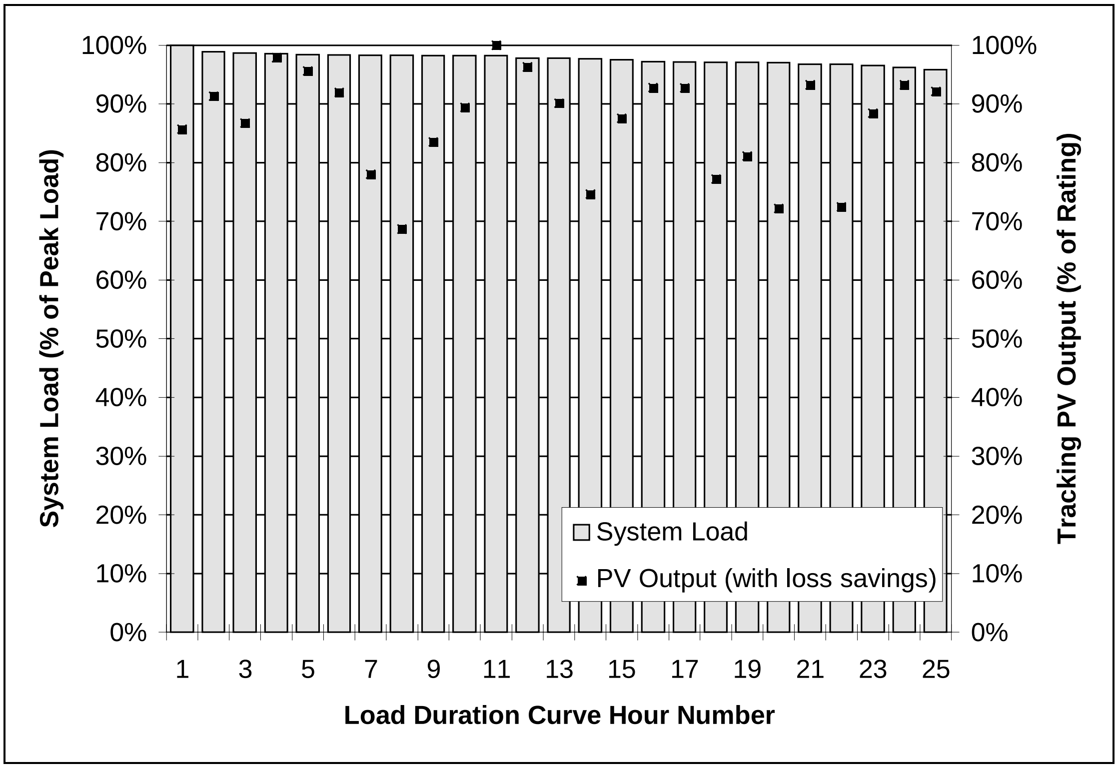


Figure 8-4. System load and PV system output for top 25 load hours (1994).

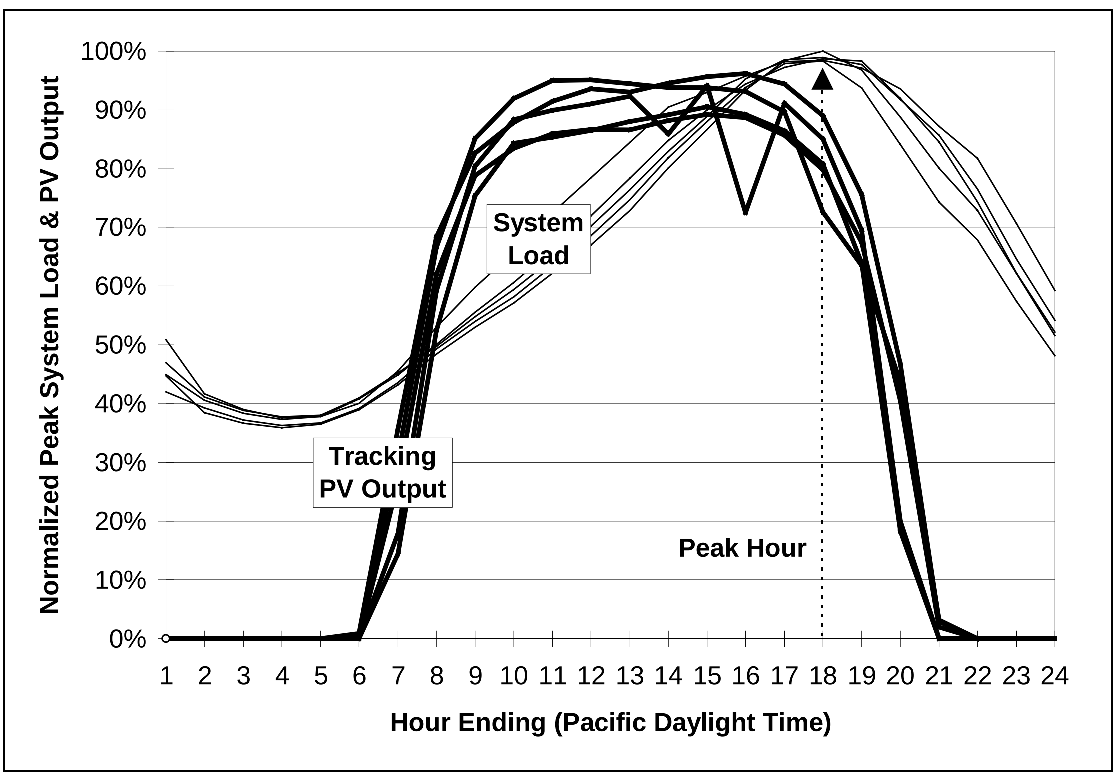


Figure 8-5. System load and PV output profiles for top 5 load days.

8.2.3 PV Pioneer Capacity Credit Analysis

The District attempts to screen and select PV Pioneer customers on the basis of a number of factors, including roof orientation. Roof orientation, and consequently the orientation of the PV array, will impact annual energy production and the system's capacity credit. According to District personnel, about 50% of the PV Pioneers have an approximate due south orientation and the remaining PV Pioneers have an orientation that ranges from due south to due west. Based on this estimate, an orientation of 30 degrees west of south is selected to represent the "composite" orientation of all PV Pioneer systems. The tilt angle is maintained at 20^{o} from the horizontal.

Figure 8-6 illustrates the impact of PV system orientation on PV capacity credit and capacity factor. Table 8-5 lists the corresponding data. The capacity credit is more sensitive to roof orientation than is the capacity factor. A 30^{o} west of south orientation yields a gain in capacity credit of about 25% while reducing annual energy production by only 1% relative to a due south orientation.

The further west the roof and PV array are oriented, the higher the PV capacity credit is because the PV output profile is being shifted to later in the day. It might appear that a due west orientation is optimal since it yields a 48% gain in capacity credit with only a 12% drop in annual capacity factor relative to the values for a due south PV system. This is not necessarily the case, however, and depends on the impact on the utility benefits of the system (as well as who owns the PV system). It turns out that the composite PV Pioneer orientation is near optimal for the District (see the following subsection).

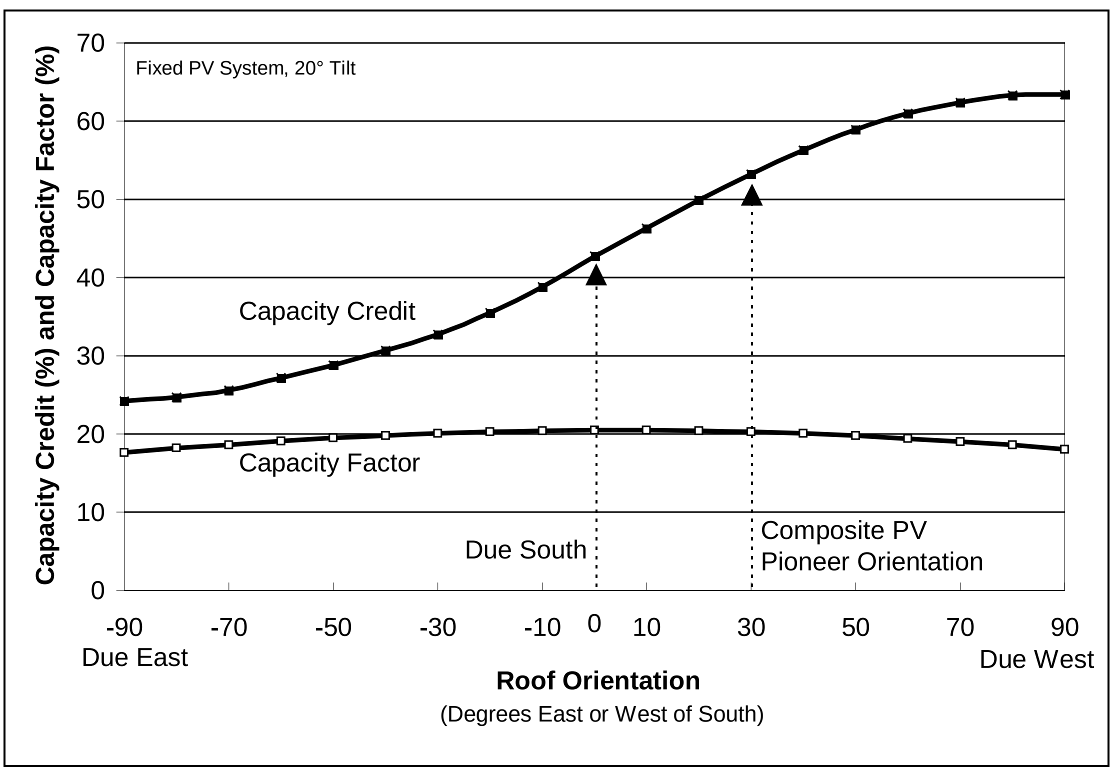


Figure 8-6. Roof orientation impacts PV capacity credit and capacity factor.

Table 8-5. Roof Orientation vs. Capacity Credit and Capacity Factor

Orientation in Degrees East (-) or West (+) of Due South	Capacity Credit (%)	Normalized to Due South Orientation	Capacity Factor (%)	Normalized to Due South Orientation
-90	24.2	0.57	17.6	0.86
-70	25.6	0.60	18.6	0.91
-50	28.8	0.67	19.5	0.95
-30	32.7	0.77	20.1	0.98
-10	38.8	0.91	20.4	1.00
0 (Due South)	42.7	1.00	20.5	1.00
10	46.3	1.08	20.5	1.00
30	**53.2**	**1.25**	**20.3**	**0.99**
50	58.9	1.38	19.8	0.97
70	62.4	1.46	19.0	0.93
90	63.4	1.48	18.0	0.88

8.2.4 Roof Orientation Impact on PV Pioneer Benefits

The benefits of distributed PV depend on many PV system design factors. The orientation of arrays is particularly of interest for rooftop PV Pioneer systems, since there are hundreds of systems mounted on a range of roof orientations. An orientation of 30^o west of south was selected to represent the composite output of PV Pioneers, as discussed in the previous subsection.

Figure 8-7 presents the total benefits of a PV Pioneer connected at secondary distribution versus array orientation. An orientation of about 45^o west of south maximizes the total benefits of these systems to the District. The 30^o composite PV Pioneer orientation yields almost optimal benefits and actually increases the total benefits by about 4% over a due south orientation. Even facing the arrays up to perhaps 30^o east of south is not a particularly poor siting strategy, as long as the PV array tilt angle is kept below 20^o. These results show that a rather relaxed siting strategy is acceptable from a total benefits perspective.

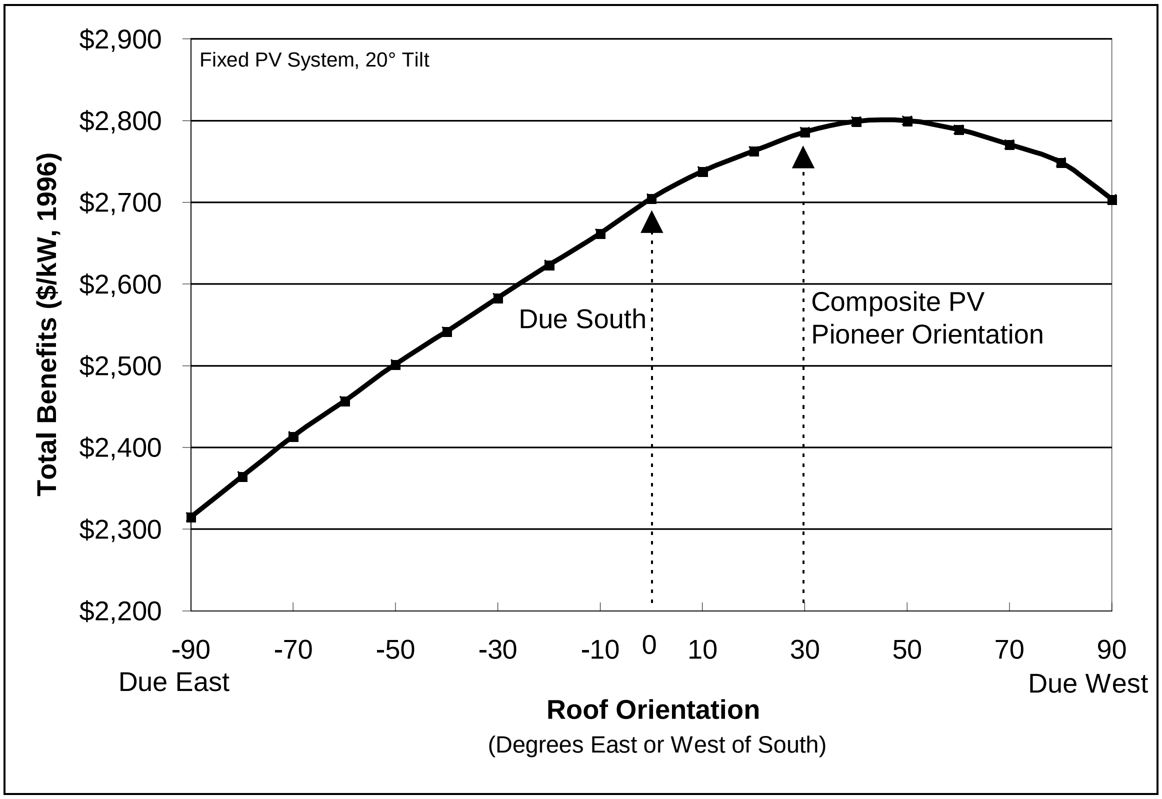


Figure 8-7. Total benefits of fixed PV systems vs. roof orientation.

8.2.5 Capacity Credit Versus PV Penetration

Figure 8-8 presents the effect of PV penetration on capacity credit, for tracking PV systems. This high-level calculation is intended to demonstrate the range of capacity credit as a function of PV penetration. The higher the amount of PV system capacity deployed within the District, the lower the capacity credit. This is caused by a shift in the peak load to later in the day as PV penetration increases. The decrease in capacity credit is minimal, however, for penetrations of PV up to 100 MW, or about 5% of SMUD's system load peak. At a 10% penetration level, or about 250 MW of PV, the capacity credit declines to about 65%. Still a fairly small impact relative to the significant increase in PV generation.

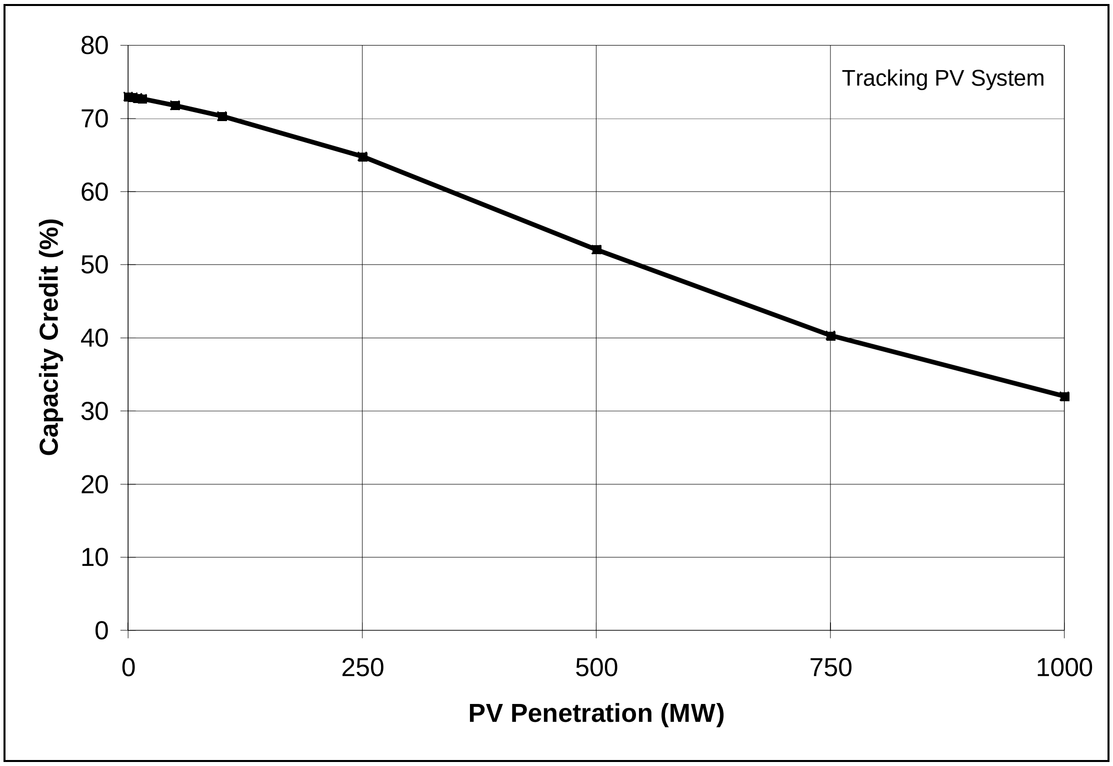


Figure 8-8. PV penetration less than 100 MW has little impact on capacity credit .

8.2.6 Capacity Benefits: Economic Results

The capacity benefits results are presented in Table 8-6. A tracking grid-support system interconnected at primary distribution yields a total capacity benefit of $431/kW, present valued in 1996 dollars. This is 37% greater than the $315/kW capacity benefit of a fixed residential rooftop system at secondary voltage. These results are based on capacity credits of 73% and 53% for tracking and fixed PV systems, respectively. Equivalent 30-year levelized $/kWh value are also presented based on 24.7% and 20.3% capacity factors.

Table 8-6. Capacity Benefits of Distributed PV Systems ($1996).

	Capacity Benefit	
	Present Value ($/kW)	Levelized 30-year ($/kWh)
Tracking PV System (at primary distribution)	431	0.0154
Fixed PV System (at secondary distribution)	315	0.0136

8.3 DISTRIBUTION BENEFITS

Strategically siting PV systems within a utility's transmission and distribution (T&D) system will maximize value by deferring investments the utility would otherwise have made, such as upgrading substation transformers and distribution lines.

From a distribution planning perspective, the District's "primary goal is to support the safe and reliable distribution of electricity to all District customers at the lowest possible cost. A key strategy for increasing the District's competitiveness is to focus on maximizing utilization of the existing investment in the distribution system to minimize new investment requirements" (SMUD 1996a,b).[43] As such, deploying PV within a utility's service area can help to achieve this strategy by helping to minimize new and future investments in distribution system capacity and reliability-driven improvements. The question is to what extent can PV help accomplish this strategy within the District?

8.3.1 Why are the Distribution Benefits so Low?

One of the conclusions of this study is that the T&D benefits, particularly the distribution deferral benefits, of distributed PV generation are somewhat low throughout the District's service area.

Three key factors drive distribution deferral benefits: The *average cost of capacity*, the utility's *real discount rate*, and the *frequency of investments*. High average costs of distribution capacity, high discount rates, and infrequent distribution investments increase deferral benefits. An examination of average T&D capacity costs provides a first-level estimate of T&D benefits potential. This can be done in much the same way that generation system capacity costs are evaluated: i.e., divide the total T&D project cost by the capacity it provides to the system to obtain the average capacity cost in $/kW. T&D benefits are not likely to be substantial if the average capacity cost is low. High average T&D capacity costs may be found, however, in situations where there are underground facilities, long conductor installations, or high project costs due to litigation and permitting.

In general, the three key factors mentioned above are low for SMUD's distribution system leading to low distribution deferral benefits. First, and most importantly, many of the distribution capacity investments have low average ($/kW) costs. The District's distribution system costs as a percent of total revenues are low: SMUD's total capital and maintenance expenditures for the distribution system projected over the next five years represent less than 10 percent of the District's total revenues, and investments in new substations account for less than 1 percent of total revenues (SMUD 1996a). The costs that could be deferred by distributed PV are incurred in items such as substation transformers and overhead facilities. The average capacity cost of a transformer, however, is relatively low. For example, a number of SMUD's demand-related investments are in 20 MW[44] transformers. These transformers have an installed cost of

[43] The District's in service assets are valued at about $1.45 billion. The distribution system accounts for 47% of the total, or $687 million -- more than any other category of District assets. This highlights the importance of the District's objective to optimally utilize its distribution assets.

[44] Technically, these are 20 MVA transformers.

about $1,000,000. This suggests that the average cost of transformer capacity is $50/kW ($0.05/W).

Second, the District has a low real discount rate, currently 2.9%, because it is a municipal utility. The lower the discount rate, the lower the value of deferring an investment. Third, the District does not plan to make many distribution expansion investments over the next five years, as described in the following subsection (SMUD 1996a,b). In the areas that distribution expansion investments are planned, the investments are being made on a somewhat frequent and incremental basis so that distribution capacity additions are well-matched to demand growth. This indicates that distribution capacity is well-utilized in areas experiencing load growth, primarily a result of being a highly interconnected utility.[45]

8.3.2 Limited Opportunities for Distribution Deferral

There are only a limited number of opportunities to defer planned investments in District distribution capacity with distributed PV. Significant growth-related distribution investments (greater than $300,000) in substations and feeders are planned in only 5 out of the District's 20 distribution planning areas over the next five years (SMUD 1996a,b). Table 8-7 presents a summary of these investments, with corresponding area load growth.

A total of about 20 significant growth-related distribution investments will be made in North Natomas (Areas 1 and 2), Folsom (Area 9), Elk Grove-Laguna (Area 15), and Galt (Area 17). These planned distribution investments total about $13 million to install about 184 MW of capacity to accommodate approximately 88 MW of load growth (17.6 MW/year) and a potential 65 MW of block loads. This investment equates to an average of some $70/kW of *potentially* deferrable distribution capacity. Even if these investments are deferrable, the contribution to the total value of distributed PV would be relatively small. The bottom line is that there are many elements that limit a large distribution deferral benefit at SMUD, including:

- high load growth (2 to 8 MW/yr) is typical in areas requiring investments in distribution capacity
- highly interconnected, high capacity, multiple substation distribution planning areas
- adequate existing distribution capacity for 3/4's of SMUD's system for the next five years: Only $15.7 million, or 0.5% of total District revenues, will be invested in new substation capacity during 1996-2000
- increasingly aggressive distribution planning criteria (moving from 80% load limit capacity criteria to 90% load limit criteria)
- coincidence of PV output with distribution loads may be inadequate and requires further study, particularly for non-dispatchable, no storage PV systems

[45] The SMUD distribution system is designed as a looped system with multiple switching locations allowing for significant flexibility to reconfigure the system for load balancing between substations, as load increases and decreases within the distribution planning area, and for quickly restoring customers in the case of outages. The looped/multiple switch distribution system design is driven by meeting specific reliability criteria.

- low cost of money (2.9% real) lowers the value of distribution deferrals

Table 8-7. Limited Opportunities for Distribution Investment Deferral (1996-2000)

Area Name (1996 Distribution Business Plan Area)	**Project Description**	**Area Growth Rate**	**Cost Estimate**
North Natomas (Area 1)	Upgrade Substation Capacity (Elverta-Powerline). Replace existing 6.25 MVA 69/12 kV transformer with new 12.5 MVA 69/12 kV bank and associated feeder work	0.4 MW/yr + 8.5 MW block load	$800,000 + $200,000
North Natomas (Area 1)	Upgrade Substation Capacity #2 (Powerline-Elkhorn). Replace existing 4.69 MVA and 3.75 MVA 69/12 kV transformers with new 20 MVA bank & assoc. feeder work	0.4 MW/yr + 8.5 MW block load	$1,000,000 + $200,000
North Natomas (Area 2)	Add Substation Capacity (North Market-Sports). Add new 20 MVA transformer + 12 kV feeder work	1.7 MW/yr + 15 MW block	$1,100,000
North Natomas (Area 2)	Acquire Substation Sites (Sites "E" and "N"). Site plan development and property acquisition for site west of planned Natomas Stadium and site at I80/I5	1.7 MW/yr + 15 MW block	$750,000
North Natomas (Area 2)	Construct Three New Feeders 1204, 1205, & 1206 (North Market-Sports). Provide looped service with 2 new 10,000 ft 12 kV extensions + a 5,000 12 kV extension	1.7 MW/yr + 15 MW block	$750,000
Folsom (Area 9)	Construct New Substation (Broadstone-Clarksville), 20 MVA 69/12 kV substation on a new site on mall property + feeder exit	4.6 MW/yr + 20 MW block	$1,300,000 + $20,000
Folsom (Area 9)	Add Substation Capacity (Intel Corporation). Add new 20 MVA 69/12 kV transformer at existing substation site	4.6 MW/yr + 20 MW block	$1,300,000
Elk Grove/Laguna (Area 15)	Construct New Substation (Laguna West), 20 MVA 69/12 kV substation to serve Laguna West + add 2000' feeder in conduit	8.7 MW/yr + 22 MW block	$1,100,000 + $70,000
Elk Grove/Laguna (Area 15)	Construct New Substation (East Elk Grove), 20 MVA 69/12 kV substation to serve East Elk Grove	8.7 MW/yr + 22 MW block	$1,100,000
Elk Grove/Laguna (Area 15)	Construct New Substation (Calvine-Hwy 99), 20 MVA 69/12 kV substation to serve Calvine SPA + 8500' reconductor	8.7 MW/yr + 22 MW block	$1,100,000 + $220,000
Elk Grove/Laguna (Area 15)	Construct New Substation (Cresswell-Heathermist). Construct a 20 MVA 69/12 kV substation to serve north Elk Grove	8.7 MW/yr + 22 MW block	$1,100,000
Galt (Area 17)	Construct New Substation (Christensen-Harvey). Construct a 6.25 MVA 69/12 kV substation + replace 5,000 circuit ft	2.2 MW/yr	$500,000 + $140,000
TOTAL	**About 20 projects in 5 planning areas to serve, in part, 88 MW load growth and 65 MW of potential block loads during 1996-2000. Average cost of capacity is about $70/kW.**	**17.6 MW/yr + 65 MW block**	**$12.9 Million**

8.3.3 Factors That Could Boost Distribution Deferral Benefits

There are several factors that could boost distribution deferral benefits. These factors include the effect of capacity utilization, distributed generation price reductions in the future, and price uncertainty, demand uncertainty, and project lead time. Preliminary application of some of these factors could provide perhaps a 50% increase in distribution deferral benefits for 1 or 2 distribution planning areas. These results, however, are not employed in this study because (a) the formulation of these factors and their application are still under development and validation is needed; (b) taking these factors into account would increase the total value of distributed PV by about 1%-3% for 1 or 2 distribution planning areas; and (c) it was deemed prudent to exclude the application of these factors so as not to distract from the main conclusions and methods presented in this study.

8.3.4 Possible Distribution Deferral Mini Case Study: Metro Air Park (Area 1)

This subsection is intended to illustrate how distributed PV could potentially be used to defer an investment in distribution equipment. Two major substation investments are planned for this area. The investments are planned for reasons of anticipated load growth and reliability. In terms of load growth, there are two major block loads that are planned to come on line in this area. First, it is anticipated that an airport expansion will result in an additional 6 MW of load. Second, an industrial park will begin to be constructed. When fully developed, the industrial park is projected to have a maximum electric demand of 100 to 200 MVA. The first 5 MVA of service is scheduled to occur within the next 5 years.

There are two substation capacity investments planned for the area. The plan is to remove the existing transformers (a 6.25 MVA transformer at one location and a 4.687 MVA and 3.750 MVA transformer at another location) and replace them with larger transformers (12.5 MVA and 20 MVA transformer, respectively). Figure 8-9 presents the load growth and distribution capacity projection for planning area #1 (SMUD 1996b).

Suppose that the plan is slightly altered and that the 6.25 MVA transformer is left at the substation, the 12.5 MVA transformer is added, and the 20 MVA transformer is not installed. This would provide sufficient capacity (a minimum of 6.25+4.687+3.75 or 14.687 MVA even if the largest transformer, i.e., the 12.5 MVA transformer, is lost due to an outage) for all load in the area except for the industrial park in case any of the transformers failed up to the year 2000.

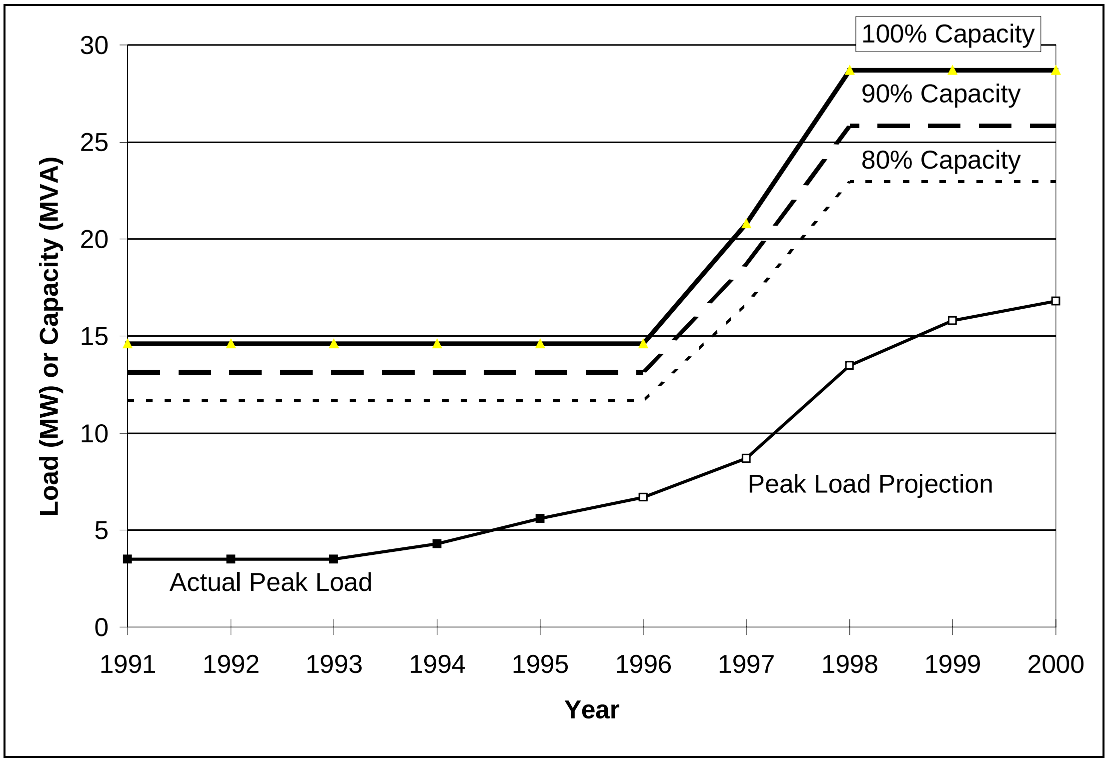


Figure 8-9. Distribution Planning Area #1 load growth and capacity projections.

Thus, it may be feasible that distributed PV generation could be used to defer the second transformer upgrade.[46] The cost of this upgrade is estimated to be $1 Million. SMUD estimates that the first increment of load will be 2 MW and will come on line in 1998. No other estimates are made for 1999 and 2000. Thus, for illustration purposes, assume that the load growth is 2 MW per year and that 20 MVA transformers would need to be installed to accommodate this growth over time.

This situation meets the criteria that the load growth is slow relative to the size of the transformer's capacity. That is, there is excess capacity on the transformer for 9 years. The investment cost relative to its capacity, however, is small. The cost is $1,000,000 for 20 MVA of transformer capacity, or $50/kW.

Although the potential distribution deferral benefit is small, the Metro Air Park distribution planning area #1 may be one of the best areas within the District for locating multi-MW distributed PV systems for other reasons, including land availability and transmission access.

[46] The match between PV output and loads requires further investigation.

8.3.5 Background Material on Distribution Benefits

There are two District documents that were used to investigate the distribution benefits of PV: The 1995 Marginal Cost Update and the Five Year Distribution Business Plan (SMUD 1995i and SMUD 1996a,b). The distribution marginal costs contained within the 1995 Update were used to calculate the economic value of distributed PV in this study since they are the accepted District planning values. The Five Year plan contains detailed project data and information on distribution planning practices that were used to elaborate on the potential for distribution savings.

Table 8-8 lists the District's 14 distribution planning areas (DPAs) according to the 1995 Marginal Cost Update and the corresponding 20 DPAs defined in the Five Year Distribution Business Plan. See Appendix A for a map. The Five Year Plan defines these 20 DPAs primarily on the basis of electrical configuration (intra-substation switching capability) and geographic boundaries. The 1995 Marginal Cost Update DPAs have a higher level of aggregation based on customer composition. A summary of distribution projects are shown in Table 8-9 (SMUD 1996a,b). Capacity additions are planned for only 5 of 20 DPAs during 1996-2000 as shown by the shaded rows in Table 8-9.

Table 8-8. District Distribution Planning Areas

Per 1995 Marginal Cost Update	Corresponding Distribution Business Plan Areas, by area #
N. Natomas	1 & 2
S. Natomas/Elverta	some of 2, 3, 4
AFB	3
Antelope	6
Carmichael-Citrus Heights	5,6,7,8
Folsom	9
Rancho Cordova	18, 19
Downtown	10, 11, some of 14
Pocket	some of 11, 12, 13, some of 14
Industrial Area	some of 14
Elk Grove-Laguna	15
Undeveloped Area	16, some of 19, 20
Galt	17
Rancho Murieta	small part of 19

Table 8-9. Distribution Loads, Capacity, and Expenditures for 1996-2000.

Area #	Planning Area	Custo-mers	Load Growth Rate (MW/yr)	New Block Loads (MW)	Substation Capacity 1996→ 2000 (MVA)	Expenditures 1996-2000 ($000)
1	**Airport-Metro Air Park S.P.A.**	**922**	**0.4 (6.9%/yr)**	**8.5**	**14.6→ 28.7**	**$2,440**
2	**Natomas**	**16,231**	**1.3 (1.4%/yr)**	**15.0**	**137.2→ 157.2**	**$2,780**
3	Rio Linda & North Highlands	13,273	0.46 (0.7%/yr)	none	89.7→ 89.7	$0
4	North Sacramento	11,640	-0.09 (-0.2%/yr)	13.0 (transfer)	98.8→ 98.8	$873
5	Arden	42,260	0.3 (0.2%/yr)	3.0 (with transfer)	210.0→ 210.0	$663
6	Antelope & North Highlands	24,707	1.8 (1.3%/yr)	7.0	184.7→ 184.7	$285
7	Carmichael & Arden-Arcade	42,591	-1.0 (-0.5%/yr)	none	262.5→ 262.5	$620
8	Citrus Heights, Oranagevale & Fair Oaks	61,936	-1.3 (-0.4%/yr)	3	400.0→ 400.0	$267
9	**Folsom**	**13,023**	**4.6 (6.2%/yr)**	**20**	**120.0→ 140.0**	**$1,425**
10	12 kV Downtown Network	2,278	1.3 (1.3%/yr)	8	150.0→ 150.0	$759
11	21 kV System	63,467	3.3 (1.3%/yr)	5-15	447.0→ 447.0	$17,258
12	Land Park, Meadowview & Pocket	22,602	0.7 (0.6%/yr)	none	159.0→ 159.0	$340
13	Fruitridge	19,198	-1.2 (-1.5%/yr)	none	116.5→ 116.5	$110
14	Elder Creek	13,604	1.1 (1.6%/yr)	none	92.5→ 92.5	$124
15	**Elk Grove, Laguna, & South Sacramento**	**42,028**	**8.7 (3.8%/yr)**	**22**	**292.6→ 372.6**	**$5,985**
16	Franklin	3,628	0.4 (2.4%/yr)	2	23.7→ 23.7	$300
17	**Galt**	**8,349**	**2.2 (6.1%/yr)**	**none**	**44.5→ 50.75**	**$805**
18	Rancho Cordova	48,625	2.4 (0.9%/yr)	none	355.0→ 355.0	$1,230
19	Rancho Murieta	4,854	0.2 (0.9%/yr)	none	38.1→ 38.1	$209
20	Wilton	5,611	1.3 (5.0%/yr)	none	38.1→ 38.1	$210
		460,827	**26.9 MW/yr**	**90-100**	**3,275→ 3,415**	**$36,683**

8.3.5.1 DISTRIBUTION PLANNING AT SMUD

The District's current design practice is to load substation transformers to 80% of their nameplate capacity rating. The design practice has resulted in the location of four adjacent substations, of no more than about 1 mile apart, so that each can absorb 25% of the load in the case of a substation outage, also referred to as a single contingency. The result is a very strong and flexible distribution system. The District is moving toward more aggressive design practices in recognition of increasing needs to cut costs while still maintaining safe, reliable service. As evidence of this movement, the SMUD Five Year Distribution System Business Plan does not call for capacity increases until the substation transformer is loaded to 90% of nameplate rating.

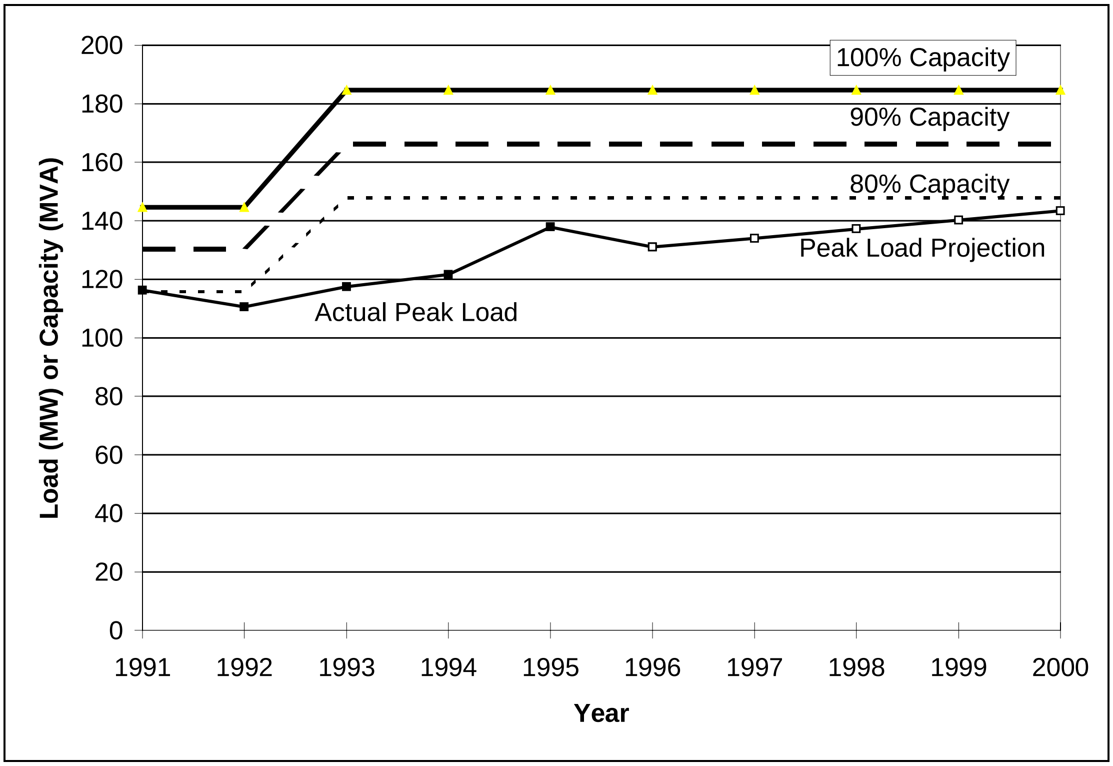


Figure 8-10. Distribution planning area capacity versus peak load (Area 6).

The upshot is that the movement towards more aggressive design practices has actually "freed up" distribution system capacity, buying SMUD time to better plan distribution system upgrades while saving the District money by putting off investments to the future. This situation is illustrated in Figure 8-10. It is reasonable to expect that SMUD will continue to explore ways to "base load" their existing distribution assets, including moving towards even heavier loading criteria during peak and emergency situations, adding ways to cool transformer banks such as forced air fans, and incorporating dynamic thermal rating criteria that account for ambient temperature, windspeed, and solar irradiance impacts on the effective capacity of distribution transformers and lines.

This movement in loading design and equipment operation practices limits the impact that distributed resources such as PV can have over the next 5 years, in terms of helping to defer investments in distribution system upgrades. SMUD's new design practice has forestalled investments in distribution capacity that may have otherwise been made. SMUD recognizes, however, that load growth forecasts can change rapidly and that the utility operating environment is dynamic. As a result Integrated Distribution Planning recommends that the Five Year Distribution System Business Plan be revised each year.

SMUD is acquiring and implementing a Distribution System Analysis Program (DSAP) in the 1996-1997 timeframe that will be used as a planning and engineering tool for such things as optimizing the distribution system to minimize losses while maximizing reliability and to evaluate the impact of integrating distributed resources. Availability of this tool will help to better quantify the direct benefits of distributed PV. In addition, SMUD will be working to improve its knowledge of detailed distribution costs, largely in response to competitive forces emerging under restructuring. The more detailed the cost information is available, the better able to target and use distributed resource technologies (including direct load control, traditional DSM, and targeted generation such as PV) to reduce costs, improve service, and maintain an advantage over competing service providers.

8.3.5.2 SITING DISTRIBUTED PV SYSTEMS

As part of the development of the QuickScreen software package, a series of siting criteria were developed to help find the best sites for distributed PV systems from the utility's perspective (Wenger and Hoff, 1996b). The siting criteria are repeated here for reference.

1. **Capital Expenditures Planned to Upgrade the T&D System**
Identify candidate sites where you plan to spend capital to upgrade transmission and distribution (T&D) facilities. The distributed PV system is designed to relieve feeders and/or substations that are nearing overload conditions and can defer planned expenditures to upgrade these facilities. Capital-intensive T&D upgrade projects such as reconductoring overhead and underground distribution lines and replacing substation transformers are preferred.

2. **Load Growth is Low Enough**
Steady load growth rates that allow the distributed PV system to defer the T&D investment are preferred. This is because the ratio of investment cost to load growth drives the T&D capacity cost savings. Divide the planned capital investment obtained from guideline 1 above by the load growth for one year. As a starting point, the resulting quantity should be at least $5,000/kW-yr. For example, assume that you plan on spending $1,000,000 to reconductor a line. The load growth should be no more than 200 kW/yr for this to be a good candidate for distributed PV generation.

3. **Isolated Radial Lines, Urban Underground Lines, and Small Substations**
Identify T&D upgrade projects that are required for isolated radial lines, urban underground lines, and small substations. Isolated radial lines can provide voltage support and thermal reduction opportunities for PV. Urban underground lines can be expensive to upgrade. Small substations (less than 25 MVA) are preferred because the PV capacity will likely be less than 5 MW in size.

4. **No Lower Cost Alternatives**
Ensure that lower cost alternatives, such as voltage regulating devices, circuit switching, transformer fans, and dynamic rating methods have been exhausted in solving capacity constraint problems.[47]

---

[47] In fact, SMUD has about 185 MW of dispatchable load control. As the District's Integrated Distribution Planning Department recognizes, it would be beneficial to target the District's load control to distribution capacity constrained areas (SMUD, 1996b).

5. **Summer Peaking Loads Between 8:00am-4:00pm**
Feeders with peak loads driven by hot summer weather conditions (e.g., air conditioning dominated peak loads) that occur some time between 8:00 am and 4:00 pm are preferred. Feeders with a significant mix of commercial and industrial customers may be preferred, since residential-dominated feeders typically peak outside the preferred time interval. The brighter the sun is during the time of the capacity constraint the better. A high summer-to-winter peak load ratio is a good indicator of a candidate site.

6. **Consider Location-Specific Issues**
Location-specific issues to consider include unshaded land (or roof-top) availability, land cost, public perception, and permitting. PV typically requires 10 acres per MW for ground-mounted systems, 200 ft^2/kW (20 m^2/kW) for commercial roof-top systems, and 100 ft^2/kW (10 m^2/kW) for residential roof-top systems. Double these area requirements for thin-film PV systems.

Based on these screening criteria, it is recommended that a list of candidate feeders be compiled to help identify potential distributed PV applications. A sample table is provided below. The table has been filled out with hypothetical candidates for distributed PV. Candidate #1 is an example of a potentially good application, while candidate #2 is not. Once potential distributed PV applications have been identified, the QuickScreen software package can be used to complete an economic evaluation.

Sample Table

Table 8-10. Identifying Potential Distributed PV Applications

	Candidate #1	Candidate #2
Project type & location	Reconductor underground feeder	Reconductor underground feeder
Capital upgrade budget ($)	$1,500,000	$2,000,000
Load growth (kW/yr)	100	2,000
Lower cost alternatives?	No	Maybe, circuit switching possible
Summer peaking?	Yes	Yes
Loads peak 8-4 pm?	Yes, peak is at 2:00 pm	No, peak is at 7:00 pm
Other issues:		
Land available?	Yes	Probably
Land cost?	Utility right of way	Expensive
Permits required?	Minimal	Minimal
Public perception?	Favorable	Needs assessing
Load data available?	Some, peak loads	None
Comments	Example of a good candidate site	Example of a bad candidate site

8.3.6 "Hidden" Costs and Benefits Recommended for Further Research

Over the past 5 years, personnel from various utilities across the country have suggested that there may be a number of "hidden costs" associated with maintaining customer load during summer peaks. These costs are hidden in the sense that they are typically spread across a number of utility cost-accounting categories making them somewhat difficult to aggregate and include in the total cost of systemwide generation capacity.

For example, it is common utility practice to offer favorable non-firm electric rates to customers who in turn are required to reduce load as directed by the utility during summer peak loads when system capacity thresholds are exceeded. There is a discernible hard cost associated with non-firm programs that is over and above the normal budget of operating the generation and T&D system. This premium could be offset by peaking generation resources such as PV.

Exceeding capacity purchase contracts may be another hidden cost. For example, if a utility has a contract to purchase 500 MW of capacity and it turns out that during a summer peak the utility requires 501 MW, there is a significant penalty the utility must pay for that additional 1 MW. There are also a number of different programs that utilities engage in to offset peak demand for electricity, including air conditioner load control programs whereby some utilities offer customers a discount on their electric bill (typically ranging from 5 to 25% during peak months) to control the operation of the customer's air conditioner.

Another possible hidden cost has to do with providing voltage support to the T&D system. Utility transmission planning personnel have stated that utilities spend perhaps 1-3% of their total gross revenue to improve voltage on their system. Without local generation, voltage support becomes particularly important and costly. Utilities have in the last several years begun to adopt the practice of charging customers for both kVARs (or reactive power) and kWs to offset the cost of supporting voltage. Maintaining voltage is required to avoid brown-outs and, often, utilities must invest in synchronous condensers on the transmission system and capacitors on the distribution system.

These peak demand related costs are not explicitly accounted for in one aggregated source so it is difficult to quantify them and to quantify the direct impact that PV and other distributed resources could have in reducing these costs. Therefore, a potential area for future research could be the examination of the costs of serving peak demand, including:

- Expenditures for voltage regulation devices such as capacitors and condensers
- Penalties that are paid for exceeding contract capacity purchase caps
- Costs of load control programs such as air conditioning load management and non-firm customer tariffs
- Costs associated with peak generation spot purchases

8.4 Transmission Benefits

The 1995 Marginal Cost Update provides 20-yr sub-transmission and bulk-transmission marginal costs that are used in this study. The systemwide PV capacity credit is assumed to apply to the transmission system, inferring that the transmission system sees the same systemwide load profile.

There are limited, if any, near term opportunities to defer transmission-related investments since the District has minimal transmission constraints. The District has investigated the possible deferral of transmission investments in the past with fairly limited results (SMUD 1995). These investments did not materialize so Transmission Planning would have to look into the possibility of deferring projects again on a case by case basis. The upshot, however, is that there are no investment projects that are favorable candidates for deferral by distributed resources. There are no reconductoring or new transmission line construction projects planned over next five years. A new 240 MVA 230/115kV bank is planned for Hedge substation at a projected cost of about $3.5 million (Personal Communication, SMUD April 1996). Approximately 50-100 MW of new generation would be needed to defer the project, but the project would eventually need to be built. Even if the project was deferred indefinitely the relative value on a $/kW basis would be very small.

Expensive transmission projects, such as bringing in a new line into an area where the siting process will be protracted, expensive, and possibly litigious, and in an area where load growth is uncertain are good targets for DR (see the Distribution Benefits section above). The dynamics of transmission systems are more complicated than distribution systems in terms of power flow and stability. Therefore, the deferral of transmission projects with distributed resources must be studied carefully from a technical engineering perspective.

Since there are limited, if any, near term opportunities for transmission investment deferral, the emphasis of siting new generation has more to do with getting the power to the District's system. Within the District, there are a number of areas where larger mulit-MW PV projects could be sited, including the metro airport in distribution planning area 1.

8.5 ELECTRIC LOSSES

Loss factors for energy and capacity values are presented in Table 8-11 and Table 8-12. Electric losses are included, or embedded, in each of the benefits evaluated (except for economic development benefits). Losses are dependent on interconnection location, ranging from 1% to 8%.

Table 8-11. Loss Factors Applied to Marginal Energy Costs

	For Customers and Resources at These Interconnection Voltages			
	Transmission (230 kV)	Sub-Transmission (69 / 115 kV)	Primary Distribution (4 / 12 / 21 kV)	Secondary Distribution (below 4 kV)
Summer Super Peak	1.0128	1.0266	1.0790	1.0794
Summer Peak	1.0108	1.0205	1.0618	1.0645
Summer Off-Peak	1.0078	1.0168	1.0456	1.0557
Winter Peak	1.0097	1.0193	1.0551	1.0592
Winter Off-Peak	1.0075	1.0160	1.0429	1.0535
Spring	1.0082	1.0171	1.0465	1.0545
Annual Average	1.0088	1.0182	1.0510	1.0581

Table 8-12. Annual Average Loss Factors for Energy and Capacity Value

	For Customers and Resources at These Interconnection Voltages			
	Transmission (230 kV)	Sub-Transmission (69 / 115 kV)	Primary Distribution (4 / 12 / 21 kV)	Secondary Distribution (below 4 kV)
Energy	1.0088	1.0182	1.0510	1.0581
Capacity	1.0120	1.0244	1.0737	1.0746

8.6 GREEN PRICING

The District has over 300 customers who have volunteered to participate in the PV Pioneer green pricing program. These volunteers, almost all of whom are residential customers, sign a 10-year contract to allow the District to install a rooftop PV system on the District's side of the meter. These PV Pioneers also agree to pay an additional $4 per month on their utility bills. According to the District, the green pricing contribution of $4/month represents about a 15% premium for the PV generation. The monthly fee is adjusted down if the District's rates increase according to the following formula:

PV Pioneer Green
Pricing Monthly Fee = $4.00 x (15% - (average residential rate increase / 15%))

Accordingly, the annual green pricing contribution from each customer depends on the average residential rate increase over the contract period. Table 8-13 presents the calculations of the green pricing benefit to the District on a present value $/kW basis in 1996 dollars. Residential rates are projected to increase about 2.3%/year over the next 10 years (SMUD 1995c). If this turns out to be true, then these customers will pay a declining monthly fee according to Figure 8-11, yielding a present value green pricing benefit of $44/kW to the District.[48]

Table 8-13. PV Pioneer Green Pricing Benefit vs. Average Rate Increases

Average residential rate increase (%/year)	Number of Years Customer Pays Fee	Present Value of Green Pricing Benefit ($/kW, 1996)
0.0%	10	100
1.0%	10	73
2.3%	**7**	**44**
3.0%	5	36
4.0%	4	30
5.0%	3	25

[48] Based on a nominally rated 3.45 kWac PV Pioneer system.

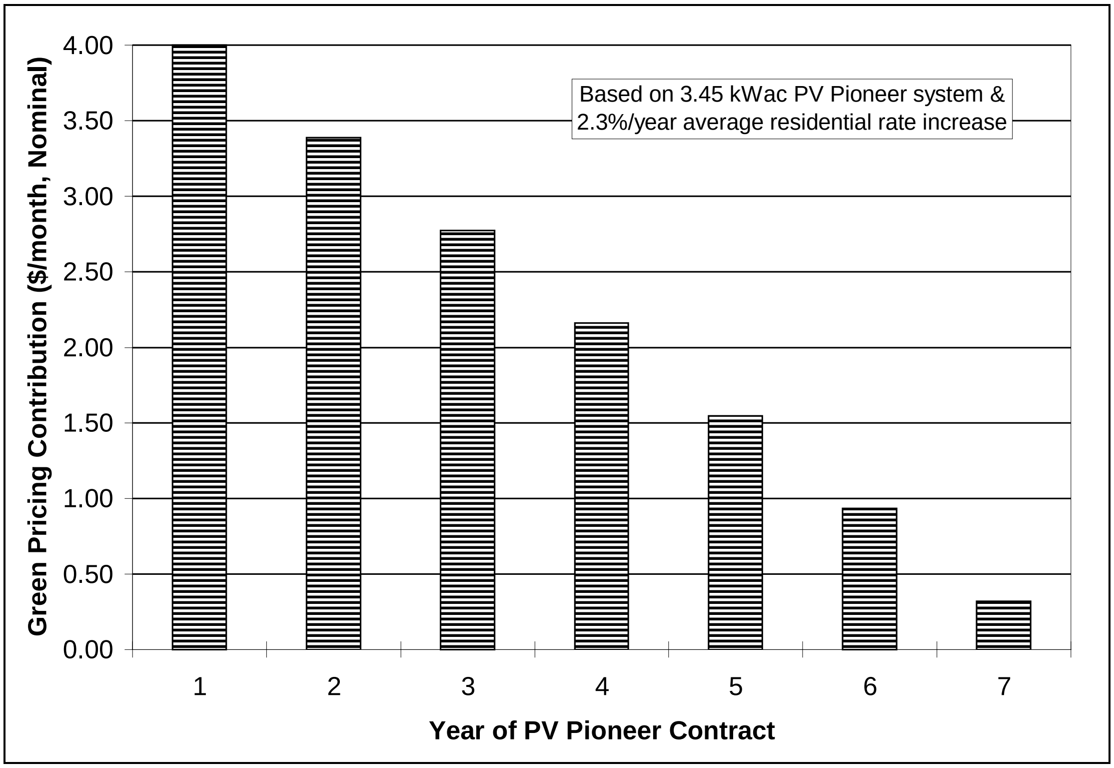


Figure 8-11. Monthly PV Pioneer fee for each year of contract (nominal dollars).

8.7 EXTERNALITIES

Environmental externalities account for the costs and benefits to society of electric power generation which are not explicitly accounted for in electric rates. A value of $0.015/kWh for the first year is the basis for calculating the externality value to the District, which includes the value of fuel price risk mitigation (Personal communication, Sacramento Municipal Utility District, January 1996). Therefore, even though externalities and fuel price risk mitigation values are calculated separately in this study, the sum of these values is set equal to the District's first-year value of $0.015/kWh. Since the value of fuel price risk mitigation is calculated to be equivalent to a first-year value of $0.0056/kWh (see Section 8.9), the equivalent first-year externality value is then $0.015/kWh minus $0.0056/kWh, or $0.0094/kWh.

The externality value is taken over the PV system lifetime of 30 years, escalated at the rate of inflation. The externality benefits results are presented in Table 8-14. A tracking grid-support system interconnected at primary distribution yields a total externality benefit of $411/kW, present valued in 1996 dollars. This is 21% greater than the $340/kW externality benefit of a fixed residential rooftop system at secondary voltage. Equivalent 30-year levelized $/kWh values are also presented based on 24.7% and 20.3% capacity factors.

Table 8-14. Externality Benefits of Distributed PV Systems ($1996).

	Externality Benefit	
	Present Value ($/kW)	Levelized 30-year ($/kWh, nominal)
Tracking PV System (at primary distribution)	411	0.0147
Fixed PV System (at secondary distribution)	340	0.0148

The externality value assigned by the District, which includes fuel price risk mitigation, is still under discussion and is meant to be "a placeholder" (Personal communication, Sacramento Municipal Utility District, January 1996). One issue is that externalities do not necessarily represent a tangible financial benefit to the District as do the other benefits identified in this study. The U.S. government recognizes the externality value of renewable generation and has developed mechanisms for capturing direct financial savings for entities making renewable investments. One mechanism is the Renewable Energy Production Incentive (REPI) which is discussed below. Another mechanism are Federal Investment Tax Credits, but the District can not take advantage of this incentive since it is a tax-exempt entity.

Pace University has extensively examined environmental externalities for electricity production (Pace University 1991). The Pace methodology is essentially the same as the recently adopted California Energy Commission methodology that places a value on avoided residual air emissions based on avoided damages to society (California Energy Commission 1995). The externality values range between $0.01/kWh to $0.045/kWh, depending on the utility's generation fuel mix. In view of externality values used in California and other states, the

$0.015/kWh externality placeholder value for the District seems reasonable. This value can be recalibrated as further work is completed in the area of monetizing externalities in the form of emission offsets (also commonly referred to as credits and allowances).[49]

The District found that only 10% of the total emissions that are regulated, namely Nitrous Oxides, Sulfur Dioxide, Carbon Monoxide, Reactive Organic Gasses, and Particulates, will be produced by local generation sources in the year 2000 (SMUD 1995c). Further, the District had to purchase 900 tons of emission offsets at a rate of four times the amount of expected local emissions (225 tons) as a mitigation measure to allow the construction of local power plants. In the year 2000 it is expected that an additional 3,000 tons/year of regulated emissions will result from power purchases (75% coming from natural gas sources and 20% from coal). Finally, annual carbon emissions (in the form of CO2) will range between 2.5 and 3.5 million tons during 1997-2005 (SMUD 1995c).

---

[49] For example, as of 1995 utilities must have sufficient emission offsets to burn sulfur-containing fuel or they must pay a $2,000/ton penalty (EPRI 1993). Also, many believe that trading of CO_2 credits is inevitable, driven by mounting scientific evidence of global warming.

8.8 RENEWABLE ENERGY PRODUCTION INCENTIVE (REPI)

The U.S. Department of Energy has made available a Renewable Energy Production Incentive (REPI) to municipal, state, and cooperatively-owned entities as a financial inducement to invest in renewable energy systems. Passed under the Energy Policy Act of 1992 (EPAct), REPI was originally restricted to investments in closed-loop biomass and wind energy plants. Under amendment to title 10, Chapter II of the Code of Federal Regulations, REPI was extended to include investments in geothermal and solar photovoltaic and solar thermal-electric resources (Congressional Record, July, 1995). REPI was intended to provide a comparable incentive to the tax credits and production payments, also made available under EPAct, to taxable entities.

The REPI payment rate currently stands at around $0.015/kWh for energy produced by systems installed before 2003 (The Solar Letter 1996). The REPI rate is adjusted annually to account for inflation and is good over a ten-year period (e.g., a system installed in 2000 is eligible for an annual payment throughout the period 2000-2010).

The stability and tenure of REPI is somewhat tenuous as it must survive the rigors of the annual appropriations process in Washington. For this reason, the REPI value is depicted with a dotted line in all of the stacked benefits bar charts in this study. REPI is a tangible value, however, and the District has applied for a REPI payment of about $219,000 for wind and PV energy production for the fiscal year ending 1995. Table 13 shows the present value and levelized REPI benefit for tracking and fixed PV systems.

Table 8-15. REPI Benefits of Distributed PV Systems ($1996).

	REPI Benefit	
	Present Value ($/kW)	Levelized 30-year ($/kWh, nominal)
Tracking PV System	269	0.0096
Fixed PV System	221	0.0096

8.9 Fuel Diversity and Price Risk

The SMUD Board of Directors set the following strategic goals to guide the resource plan: stable rates, clean air, local economic development, and decreased risk through fuel diversity (SMUD 1995a, p. 1). The approach in the integrated resource planning process was to select a resource strategy that provided the maximum contribution to each of these strategic goals. Many of the costs and benefits associated with different technology options were relatively easy to quantify in terms of dollars. Others, however, were more difficult to quantify. These were termed in the category of 'externalities.'

The District's approach to incorporating externalities into the decision making process was to study a range of strategies constructed to achieve varying degrees of each of the Board approved goals (SMUD 1995c, p. 56). That is, externalities were first assessed from a qualitative perspective and subsequently a first-year value of $0.015/kWh was assigned for externalities, including the value of fuel price risk mitigation. Therefore, even though externalities and fuel price risk mitigation values are calculated separately in this case study, the sum of these values equals a first-year value of $0.015/kWh.

The following sections build upon the District's work in the 1995 IRP and attempts to assign an economic value to several of the externalities that support the Board's goals. This section estimates the benefit of decreased risk through fuel diversity. Section 8.10 estimates the economic development benefits associated with a 2 MW per year investment in PV that results in the construction of a 10 MW PV manufacturing facility.

8.9.1 Benefit of Decreased Risk Through Fuel Diversity

SMUD has observed that it is entering into a more competitive environment where it will compete for customers with other utilities, as well as independent power producers (IPPs) and power brokers. The customers who may initially be targeted by its competitors are those who buy large amounts of power. These customers may be able to negotiate the best rates. Other customers may be left with stranded investment costs. (SMUD 1995b, p. 8)

This is an important observation within the context of managing risk and uncertain fuel prices. One of its implications is that a change in fuel prices can have a direct and indirect effect on rates. The direct effect is the one-to-one correspondence between fuel costs and variable costs for the gas-fired portion of the utility's generation. The indirect effect is the change in rates that could occur due to rate-sensitive customers leaving the system (either to a competitor or to another form of generation) if rates change too much relative to the cost of the alternative; the remaining customers are left to cover a proportionately greater share of the fixed costs.

This suggests that all customers are concerned about how the utility manages its fuel price risk. Large consumers of electricity, whose bills are primarily composed of energy costs (e.g., industrial customers), are concerned about the direct effect of a change in fuel prices on rates. Small consumers, whose bills are composed mainly of fixed costs (e.g., residential customers), may not be sensitive to fuel price changes directly but are concerned about the indirect effect due to other customers leaving the system. This suggest that the most relevant perspective to take in this analysis is the customer or industry that is most sensitive to fuel price changes because all other customers may be affected by their actions.[50]

8.9.2 Motivation

Assessing the effect of fuel price uncertainty from a specific customer's perspective is performed as follows.

1. Determine the utility's exposure to fuel price risk.
2. Determine how fuel price changes are allocated to different customer classes.
3. Estimate the fraction of the customer's bill that is related to energy costs.
4. Assess the range of possible fuel price uncertainties.
5. Evaluate a customer's response to fuel price changes.

The utility can influence the first three factors based on the investments it makes, the contracts it negotiates, and the rate structures that it establishes. The utility has no influence over the fourth and fifth factors, i.e., the range of fuel price uncertainty (this is determined by the market) and the customer's response to fuel price changes (this is determined by the customers' risk preferences, the available alternatives, and the customer's competitors).

Assume, for example, that the utility allocates fuel cost changes linearly among all customers based on their energy consumption. In this case, the change in rates due to a change in fuel prices equals the percent change in fuel prices times the fraction of the utility's energy costs related to the fuel that has uncertain prices times the fraction of the customer's bill that are energy related. That is, an X percent change in fuel prices translates to an X*Y*Z percent change in rates, where Y is the fraction of the utility's energy costs related to the fuel that has uncertain prices, and Z is the fraction of a customer's bill that is based on energy costs.

Consider how SMUD's customers are affected by fuel price uncertainty. Assume that total energy costs are linearly related to the energy generation mix and that 75 percent of the short-term contracts are based on natural gas-fuel power (SMUD 1995b, p. 27). In this case, SMUD's three scenarios result in 35 percent (Base Case), 41 percent (Competitive Balance), and 48 percent (Rate Minimization) of SMUD's energy production coming either directly or indirectly (through purchases) from natural gas-fueled power (SMUD 1995c, pp. 92, C2-1 through C2-3). That is, Y in the above equation equals 35, 41, and 48 percent for the Base Case, Competitive Balance, and Rate Minimization scenarios.

What are the projected natural gas prices (i.e., X in the above equation)? SMUD produced three estimates of natural gas prices. The prices were based on escalation rates of a low of 3.5 percent, a best estimate of 5.4 percent, and a high of 7.3 percent. This suggests that after 5 years, the low

---

50 This suggests that it may even be desirable to design a product that protects this industry from increasing fuel prices while it allows them to benefit from decreasing fuel prices. That is, it may be desirable to develop some sort of option contract.

escalation results in gas prices that are 8 percent lower than the best estimate, and the high escalation results in gas prices that are 9 percent higher than the best estimate.

It seems that this range of estimates may be conservative in light of the uncertainty that has recently occurred in natural gas prices. Consider, for example, the range of gas prices that were projected in 1991. The 1991 gas price was $3.00 per MMBtu and was projected to cost $4.66 per MMBtu in 2000 (SMUD 1995b, p. 8). This corresponds to a 5 percent annual escalation rate. This implies that 1995 price was estimated in 1991 to be $3.64 per MMBtu. Actual 1995 prices are $2.70 per MMBtu, which are 26 percent lower than they were projected to be four years ago.

This suggests that a wider range of possible gas prices may be warranted. For example, a 50 percent decrease (there is a lower bound on gas prices due to the fixed transportation charges embedded in the natural gas prices) and a 100 percent increase might be considered more reasonable scenarios to bound the potential impact of fuel price uncertainty.

Figure 8-12 presents the change in a customer's utility bill based on a 100 percent increase in natural gas prices as a function of the fraction of the customer's total bill that is based on the utility's energy production costs. Residential customers are likely to be around the 25 percent mark while industrial customers may be at 75 percent or even higher.

There are several implications of the figure. First, customers who have a low fraction of their bill due to energy production costs (i.e., residential customers) are relatively insensitive to changes in natural gas prices under all three scenarios. Second, customers who have a high fraction of their bill due to energy production costs (i.e., industrial customers) could see their utility bill increase by a third or more due to a doubling of natural gas prices. Third, and perhaps most interesting, is that the scenario SMUD decides to pursue does not have a major effect on the change in bills due to a change in fuel prices for any of the customers. For example, a customer who has 75 percent of the bill due to energy costs will experience a 26 percent (Base Case), 31 percent (Competitive Balance), or 36 percent (Rate Minimization) increase in their utility bill due to a doubling of gas prices. The point of this is that when approached from this perspective, the reduction in rate uncertainty is not very dependent on the scenario that SMUD selects to pursue.

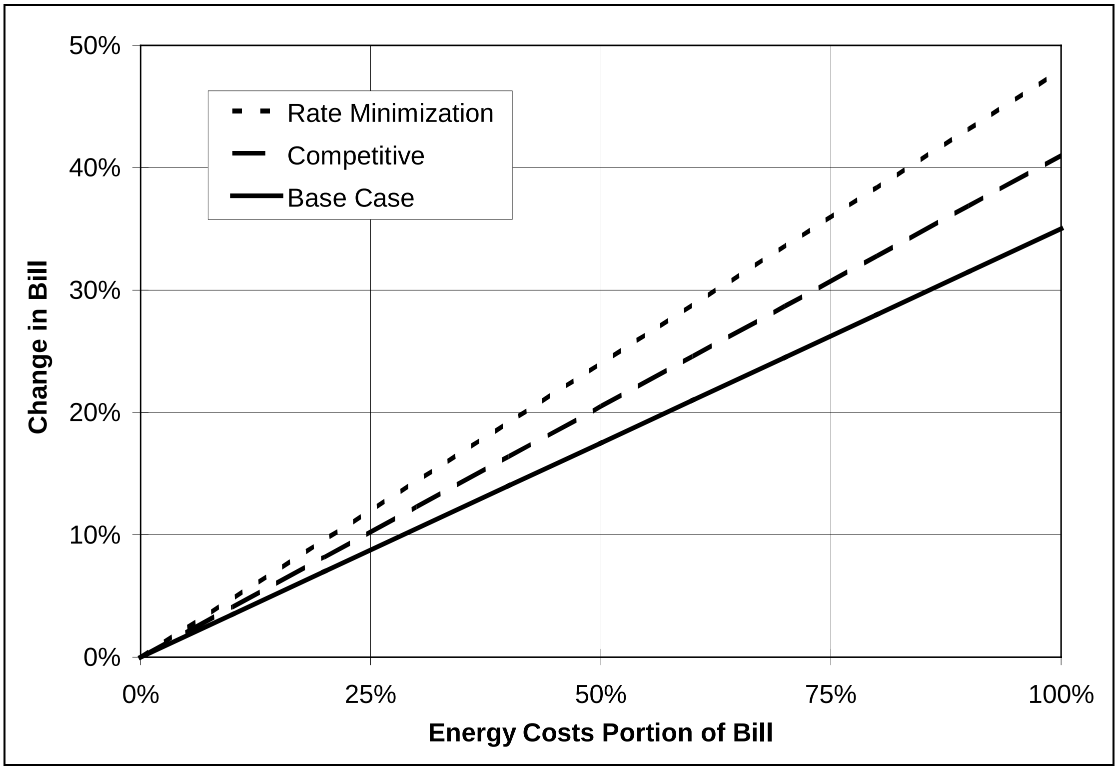


Figure 8-12. Utility bill changes for 100 percent increase in natural gas prices (linear allocation).

It is tempting to conclude that the strategy that SMUD selects is almost irrelevant from a fuel price risk perspective. A factor that needs to be given consideration, however, is that the utility does not have to linearly allocate fuel price risks. Rather, another possibility is to hedge fuel price risks using new purchases of renewable energy technologies for consumers who have a significant portion of their bill due to energy costs. Assuming, for example, that SMUD obtains an equal amount of revenue at each point on the x-axis, another approach is to follow the base case strategy but to allocate the risk in fuel price changes as presented in Figure 8-13; the Rate Minimization strategy from Figure 8-12 is included for reference purposes. Such a strategy substantially reduces the bill change corresponding to a fuel price change for consumers who have a large portion of their bill due to energy costs while it slightly increases the bill change for consumers who have a larger portion of their bill due to fixed costs. This figure suggests that it may be beneficial to manage fuel price risks for those customers most sensitive to price changes rather than for the utility as a whole.

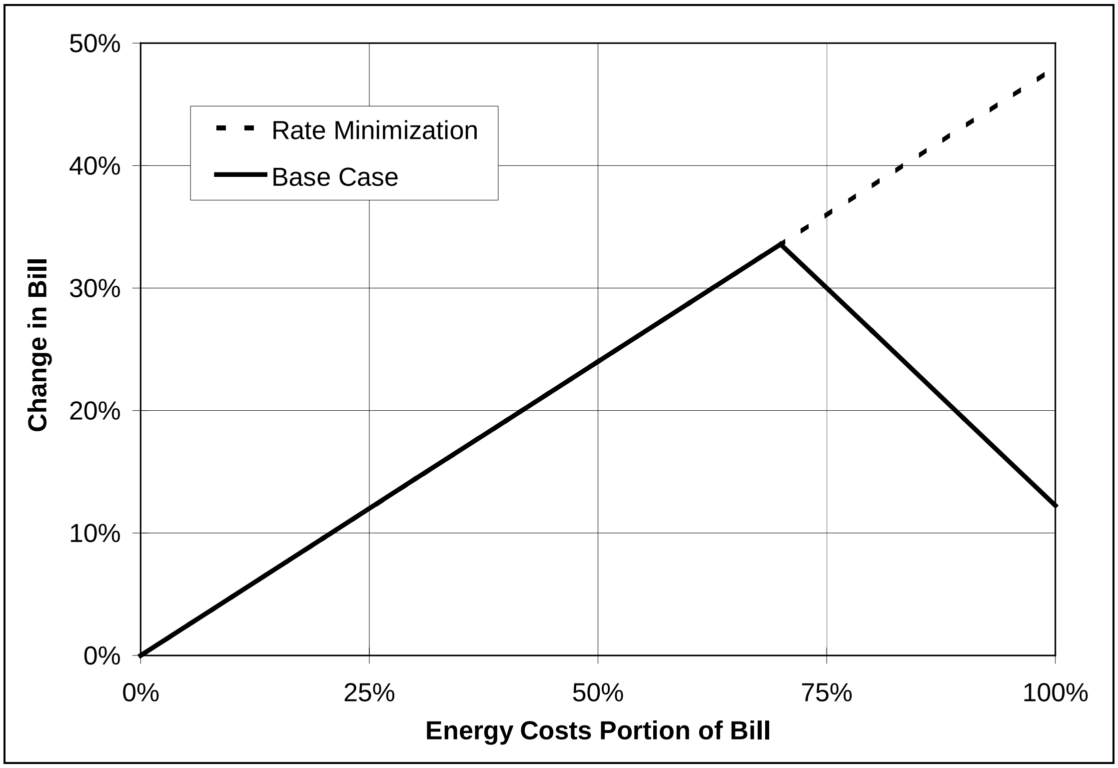


Figure 8-13. Utility bill changes for 100% increase in natural gas prices (non-linear allocation).

Figure 8-13 represents one possible way of allocating fuel price changes in a non-linear manner and thus is not meant to represent the most efficient allocation. Many other possibilities exist. For example, another possible arrangement is to structure the allocation so that rate-sensitive customers have low risk if fuel prices increase but benefit if fuel prices decrease. In essence, this is a type of option where if the price of natural gas increases, there is a small increase in rates while if the price of gas decreases, there is a large decrease in rates.

8.9.3 Valuation Methodology

The previous subsection provides the motivation for using renewable technologies to manage risk. While managing fuel price risk may not be a major issue when the calculating the direct effect of fuel price changes given that no customers leave the system, if may be an issue to all customers due to indirect effects if rate-sensitive customers are induced to leave the system. This section determines the value of the reduction in risk.

A straight forward way to determine the cost of eliminating fuel price risk is to calculate the cost of entering into a long-term, fixed price fuel contract, such as a natural gas contract. Entering into such a contract is comparable to taking out a loan and should, as such, be considered a form of debt financing. Thus, the fuel costs specified in the contract should be discounted at the firm's cost of debt. One determines the annual contract cost required to provide the same amount of electricity as the PV plant. The present value of these annual costs discounted at the cost of debt equals the value of the energy supplied by the PV plant.[51]

8.9.4 Results

Suppose that the cost of entering into a 30 year fixed price fuel contract follows the schedule presented in Table 8-16.[52] It assumed that the heat rate of the plant used to convert the gas to electricity is 10,000 Btu/kWh, that the cost of debt is 6.3 percent, and that the PV plant has a 25 percent capacity factor and 30 year life. The present value cost of such a contract is $1,180/kW. This is 25 percent greater than the value obtained based on SMUD's marginal energy costs.

Table 8-16. Possible Fixed Price Contract Costs

Year	Price	Year	Price	Year	Price
1996	$2.47	2006	$4.15	2016	$5.45
1997	$2.77	2007	$4.25	2017	$5.57
1998	$2.94	2008	$4.40	2018	$5.69
1999	$3.11	2009	$4.57	2019	$5.81
2000	$3.25	2010	$4.74	2020	$5.93
2001	$3.43	2011	$4.86	2021	$6.05
2002	$3.61	2012	$4.97	2022	$6.17
2003	$3.74	2013	$5.09	2023	$6.29
2004	$3.87	2014	$5.21	2024	$6.41
2005	$3.98	2015	$5.33	2025	$6.53

8.9.5 Conclusions and Discussion

Several comments are in order based on the preceding analysis. First, eliminating the effect of fuel price uncertainty is not necessarily always positive. When one enters into a long-term contract, prices may go up or down. The one purchasing the fuel contract benefits if prices increase but is placed at a disadvantage if prices decrease; that is, the one purchasing the contract can end up in a situation of being locked into a long-term, high cost contract.

Second, the methodology employed in this section is not exact because it does not recognize that the heat rate of new gas turbines may continue to improve. This is not an issue if the generating unit used to generate the electricity will not be replaced over the life of the fuel contract. If,

---

[51] This approach can have an indirect cost. The direct cost equals the present value cost of the fuel contract. The indirect cost equals the increased cost of future investments due to the fact that entering into the contract changes the firm's capital structure. There is not, however, an indirect cost for a municipal utility because it is financed using all debt.

[52] These prices (from 1996 to 2015) correspond to the High Case March 1995 Gas Price Forecast (received from Barry Brunal, SMUD, February 6, 1996). They are thought to be representative of what SMUD would have to pay to enter into a long-term contract. Prices beyond 2015 are extrapolations.

however, technological developments occur so that the heat rate declines and the owner of the fuel contract is able to take advantage of the new developments (e.g., by either retrofitting or scrapping the unit), this lost opportunity needs to be considered.

8.10 SERVICE REVENUES RESULTING FROM ECONOMIC DEVELOPMENT

SMUD's investment in PV can have economic development benefits to its ratepayers. This section evaluates the benefits of a commitment by SMUD to purchasing, on average, 2 MW of PV per year for five years from a specific manufacturer. It is assumed that this commitment attracts a new factory capable of producing 10 MW per year when in full production (SMUD 1996d). Benefits that accrue to ratepayers include that SMUD's fixed costs are spread out of over more units of sales and that there are expanded business and employment opportunities. *This study conservatively counts only the increased revenue (minus costs) from electricity sales to the new PV factory as the total economic development benefit.*

A typical approach to determine all of the benefits associated with economic development is a multiplier analysis using an input-output (I-O) model. This approach has been applied to environmental technologies in general (e.g., Laitner, Goldberg, and Sheehan 1995, Hoerner, Miller, and Muller, 1995), to renewable energy and energy efficiency technologies (Geller, DeCicco, and Laitner, 1992), to the construction and O&M associated with renewable energy plants in specific regions (Clemmer 1994, Roberts, et. al., 1995), and to the construction and operation of a PV module manufacturing facility in Fairfield, California (Demeter 1992).

Multiplier analysis estimates the overall change in the economy due to isolated changes in final demand from one of its industries. The analysis focuses on direct (on-site), indirect (supplier), and induced (respending) effects. Figure 8-14 illustrates some of the direct and indirect effects resulting from a purchase by SMUD from a PV manufacturer; induced effects are not included.

The direct effects are that SMUD is making a payment to the PV manufacturer to purchase PV modules (purchase costs), and SMUD has increased costs and revenues due to the increased demand by the PV manufacturer to produce the modules (service costs and revenues). Indirect effects include the increased energy costs and revenues due to the production costs that the manufacturer pays to other industries for inputs and to workers for wages. The figure also indicates that other purchases, such as exports to another market, have a direct effect on SMUD's costs and revenues. This enables SMUD to leverage its investment. Again, this study assumes that only the direct effects are counted and captured by the District.

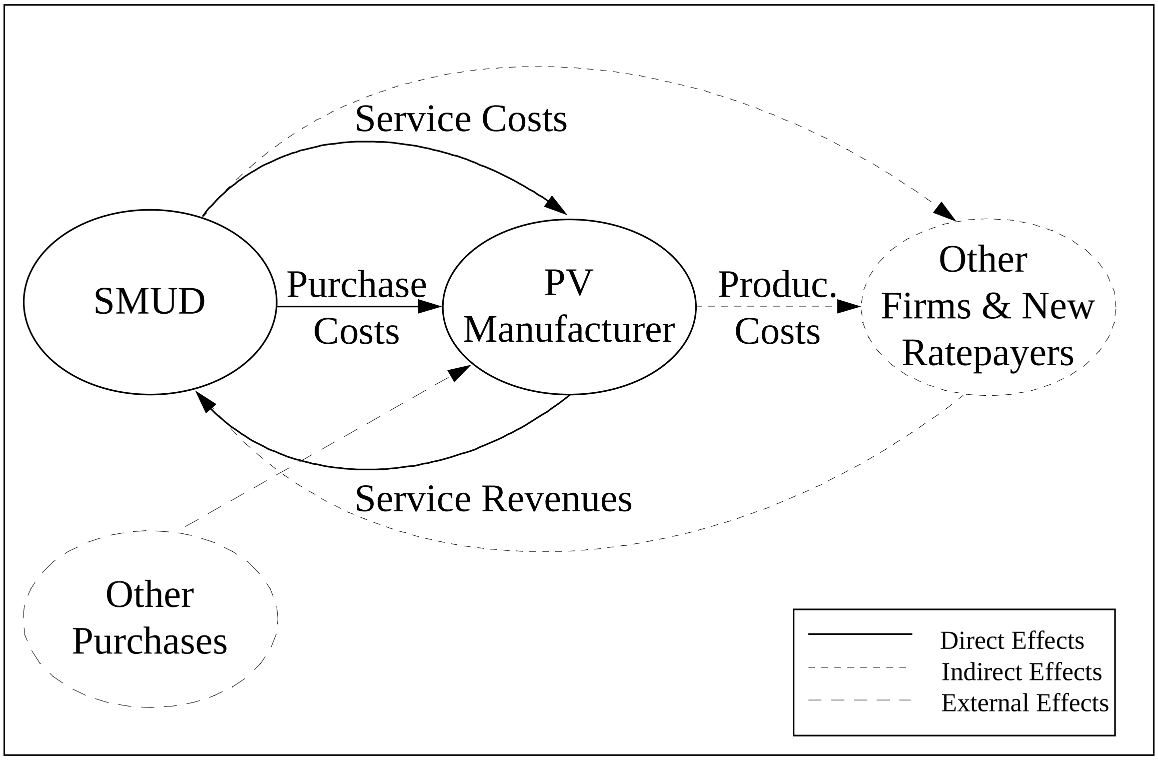


Figure 8-14. Direct and indirect effects of SMUD's PV purchase commitment.

8.10.1 Approach

A full I-O analysis is beyond the scope of this project due to the fact that the regional effects need to be determined for SMUD's service territory. As a first step, however, it is feasible to consider the direct effects. That is what is considered in the following analysis. *No consideration is given to the indirect effects (the dashed arrows in Figure 8-14) or the induced effects to simplify the analysis and to develop a conservative estimate*. The analysis is based on a thin film module factory that can produce 10 MW of PV per year when there are three shifts. It has a power demand of 1.8 MW (von Meier 1994) whenever it is in operation and is likely to generate around 80 new jobs (Demeter 1992).

As shown by the solid lines in Figure 8-14, benefits that accrue directly to SMUD are based on the difference between the revenues that SMUD receives from the PV manufacturer and the service costs SMUD incurs to satisfy the facility's demand. Purchase costs need to be dealt with separately if the value and cost of the purchase is not the same because they have induced effects. Service revenues are based on SMUD's economic development rate schedules (for the first five years of the facility's life) and SMUD's time-of-use rate schedules (for subsequent years). The facility is on SMUD's economic development rate schedule GS-ED1 based on the number of jobs it creates.[53] It is assumed that there is no rate escalation during the first five years and that rates begin to escalate at the general rate of inflation (3.6 percent) in the sixth year. The costs are

[53] The GS-ED1 schedule is an economic development schedule when 50 new jobs are created. The GS-ED2 schedule is an economic development schedule when 250 new jobs are created.

based on the 1995 Marginal Cost Update by SMUD's Resource Planning and Evaluation Department. The costs escalate at the general rate of inflation (3.6 percent) after 20 years.

Table 8-17 presents the energy costs and Table 8-18 presents the facilities and demand charges for three current rate schedules for customers taking firm service at the primary level (4 kV to 21 kV service). Rate schedules GS-ED1 and GS-TOU are used in the analysis; GS-ED2, the economic development rate schedule for large facilities (i.e., more than 250 jobs), is included for reference purposes. The annual average in Table 8-17 is based on the number of hours in each period.

Table 8-17. Customer Energy Rates for Firm Service at the Primary Level ($/kWh)

	GS-ED2	GS-ED1	GS-TOU
WINTER (8 months)			
Peak period	0.03700	0.04524	0.04750
Off-peak period	0.03100	0.03757	0.03950
SUMMER (4 months)			
Super-peak period	0.04400	0.05572	0.05900
Peak period	0.03700	0.04524	0.04750
Off-peak period	0.03100	0.03757	0.03950
Annual Average	**0.03422**	**0.04184**	**0.04401**

Table 8-18. Customer Facility and Demand Charges for Firm Service, Primary Level

	GS-ED2	GS-ED1	GS-TOU
WINTER (8 months)			
Facilities ($/kW/mo.)	1.15	3.33	6.65
SUMMER (4 months)			
Facilities ($/kW/mo.)	1.15	3.33	6.65
Demand ($/kW/mo.)	21.85	15.85	9.40
ALL SEASON			
Facilities ($/kW/mo.)	3.45	3.45	3.45
Annual ($/kW/yr)	**142.60**	**144.76**	**158.80**

8.10.2 Results

Table 8-19 presents the net benefit of the difference between the added revenues and added service costs. It assumes that all facility and demand related charges are incurred whether the factory has partial or full production, and that energy charges are proportional to production levels. The first and second columns are the present value of the net benefit, in absolute magnitude and per kW of SMUD's purchases.[54] The third column, which is in the same units as the adder that SMUD gives to renewable technologies, is the net benefit per kWh given in the first year. The third column equals the second column assuming a 25 percent technology capacity factor, a 30 year technology life, and a 3.6 percent escalation rate.

Table 8-19 presents several scenarios. The first row represents the scenario where the factory produces 2 MW per year, all of which is sold to SMUD; at the end of 5 years, there is no more production (i.e., the plant closes at the end of five years). The second through fourth rows represent the scenarios where there are additional purchases (i.e., SMUD is not the only purchaser), with the factory producing 3.3 MW of PV in the first year (one shift), 6.6 MW in the second year (two shifts), and 10 MW in subsequent years (three shifts). Rows two through four are the benefits for 5, 20, and 30 years of facility operation.

Table 8-19. Direct Benefits to SMUD of 10 MW PV Manufacturing Facility

	Revenues - costs (present value)	Revenues - costs /kW of purchases (present value)	Revenues - costs /kWh of purchases (first year credit)
5 years of operation (SMUD is only customer)	$1,112,000	$118/kW	$0.003/kWh
5 years of operation (There are other customers)	$1,781,000	$188/kW	$0.005/kWh
20 years of operation (There are other customers)	$5,210,000	$551/kW	$0.013/kWh
30 years of operation (There are other customers)	$6,694,000	$708/kW	$0.017/kWh

8.10.3 Discussion

The results presented in Table 8-19, although substantial, may be conservative. Several factors are likely to result in more benefits to SMUD than presented in Table 8-19. First, only the direct effects are included in this analysis. There are indirect effects, such as the increase in energy consumption by additional workers that the PV factory employs and the industries in SMUD's service territory that supply inputs to produce the PV modules. There are also induced effects, including the change in consumer income and the potential development of a PV industry. The indirect and induced effects often result in substantial increases over the direct effects. Demeter

---

[54] SMUD's 10 MW of purchases over 5 years corresponds to 9.45 MW of purchases when present valued at a real discount rate of 2.9 percent.

(1992), for example, estimates that the combination of all effects (direct, indirect, and induced) result in output sales that are eight times as large as direct effects alone in the case of a PV module manufacturing facility in Fairfield, California.

Second, the factory's energy consumption estimate appears to be low. In a recent paper, von Meier (1994) reviews the energy required to produce PV. von Meier states that energy payback times for PV technologies calculated by different authors range from 5 to 10 years for monocrystalline, 3 to 5 years for polycrystalline, and 0.5 to 2 years for thin-film modules. The lowest estimate in all of the literature that the author reviewed was for the thin-film module factory upon which the energy consumption in this analysis is based (i.e., a 1.8 MW load for a 10 MW manufacturing facility). Thus, the estimate may be low for a thin-film factory in general. In addition, there is a major distinction between the energy input required for silicon processing, which is high (70 to 95 percent of total energy consumption) for crystalline modules and practically negligible for thin-film modules. Thus, the energy consumption could be much higher for other types of PV module manufacturing facilities.

On the other hand, there are several factors that could reduce the value presented in this analysis. First, induced effects could have a negative effect if SMUD's purchase costs exceed their value. Second, SMUD's actual marginal costs associated with the new factory may be higher than SMUD's projected marginal costs. Third, there is the possibility that SMUD's investment will not be leveraged by other purchases of PV. In this case, the direct benefits will be based only on SMUD's purchases and they will terminate at the end of five years when SMUD's purchase commitment is satisfied. Fourth, the rate schedules were based on firm service and the actual facility may not take firm service.

In any case, the results presented in this section suggest that there can be substantial economic development benefits associated with an investment by SMUD that results in the operation of a PV manufacturing facility in SMUD's service territory. It is recommended than an economic development value of $708/kW be assigned as a placeholder based on this analysis.

This analysis has not included the indirect and induced economic effects (both positive and negative). The positive effects include the economic multiplier effects mentioned earlier. The negative effects include a reduction in economic development benefits if SMUD is required to pay more for the PV than its value is to SMUD because this will raise rates and thus make all customers not as well off.

8.10.4 Conclusions

Distributed generation technologies have been viewed with a great deal of interest by utilities because they simultaneously satisfy multiple requirements. That is, it is feasible to save energy costs, generation capacity costs, T&D capacity costs, and reduce electrical losses by locating a technology in a capacity constrained area.

A similar conclusion can be reached in terms of the added benefits provided by PV: it may simultaneously satisfy the needs of a diverse set of customers because it has attributes that are attractive to different customers in different ways. This suggests that the utility may want to divide the value of PV up according to its attributes and sell those attributes to those that want to purchase it. For example, the utility could:

- sell fuel price risk mitigation benefits to heavy energy users to protect them from increasing fuel prices
- sell fuel price risk mitigation benefits to light energy users to protect them from covering the cost of stranded investments due to rate-sensitive customers leaving the system
- sell economic development benefits to all customers because it can lower their rates
- sell green pricing to residential customers by locating the PV plants on their rooftops
- sell clean air benefits to environmentally conscious customers or to those that are required to satisfy certain emissions standards

9. Residential Rooftop PV Supporting Analysis

This section presents the supporting analysis for SMUD-owned and customer-owned PV systems on residential roofs (see The Market for Utility- and Customer-Owned PV section). The District-owned analysis builds on information about roofing materials used for residential homes, SMUD's experience to date on installing PV Pioneer systems on existing homes, the orientation of homes in Sacramento County, and the available square footage on the roofs. The customer-owned analysis builds on these same informational items plus census tract data on marginal tax brackets of Sacramento County residents. The analysis includes totals for the entire Sacramento County and for the 14 SMUD service territory areas.

9.1 Market Population as a Function of Marginal Tax Bracket

Detailed census data from the 1990 census were obtained by census tract for the District's service area. The 207 census tracts for Sacramento County provide a more detailed breakdown on income data than a breakdown based on zip code. These data break down the household income for each tract into 25 different income levels. It is assumed that the household income amounts from the census closely approximate the adjusted gross income from federal tax returns. A further breakdown to separate each income group into "joint" and "single" income tax filers was made in order to determine the market population as a function of tax bracket. This was done by utilizing information from the California Franchise Tax Board (FTB) 1994 Annual Report which shows the number of tax returns filed jointly and in total across different income brackets for Sacramento County in 1993. Although the FTB data are from 1993 and the U.S. census data are from 1990, it is assumed that the overall demographics did not change to affect the applicability of this method. The percentage of joint filers was applied to the U.S. census data to get an approximation of how many filers in each census tract income group filed jointly. It was then assumed that the remaining filed single, for simplification.

A county-wide and District-area analysis was made to determine how many households are in each marginal income tax bracket. The breakdown was based on the 1994 tax rate schedules which breaks out the federal tax brackets by adjusted gross income (AGI) as shown in Table 9-1.

Table 9-1. Federal Marginal Tax Brackets by Adjusted Gross Income

Marginal Tax Bracket	AGI Range for Single	AGI Range for Joint
15%	\$0 - \$22,750	\$0 - \$38,000
28%	\$22,751 - \$55,100	\$38,001 - \$91,850
31%	\$55,101 - 115,000	\$91,851 - 140,000
36%	\$115,001 - \$250,000	\$140,001 - \$250,000
39.6%	\$250,001 +	\$250,001 +

In instances where the census income range include a portion from two different marginal tax brackets, it was assumed that the distribution of income across the range was equal. Because there is no detail available for household incomes above $150,000, the distribution between the 36% and 39.6% brackets is unknown. Therefore, all the households falling into this group are grouped into the 36% bracket.

Table 9-2 presents a summary of the number and percentages of households that fall into each income tax bracket in Sacramento County
.

Table 9-2. Distribution of Households by Tax Bracket in Sacramento County

Marginal Tax Bracket	# of Households	% of Total Households
15%	170,997	43.07%
28%	195,825	49.32%
31%	23,406	5.89%
36%	6,838	1.72%

Table 9-3 summarizes the distribution by marginal tax bracket within SMUD's distribution planning areas. This was accomplished by grouping census tracts into each of the defined areas.

This shows that Carmichael / Citrus Heights, Folsom, Rancho Murieta, Elk Grove / Laguna, and Galt have a higher percentage of higher income households than average for the county. Combined with areas of the highest marginal distribution capacity costs, the areas with the higher incomes and the higher distribution costs in order are:

- Folsom
- Elk Grove / Laguna
- Rancho Murieta
- Galt
- Carmichael / Citrus Heights

Table 9-3. Percentage of Households by Tax Bracket & Planning Area

Distribution Planning Area	Marginal Tax Bracket 15%	28%	31%	36%
Downtown	62%	34%	3%	1%
Pocket	46%	47%	6%	1%
Carmichael/Citrus Heights	41%	50%	7%	2%
Folsom	31%	57%	11%	1%
Antelope	28%	65%	6%	1%
Rancho Murieta	19%	55%	15%	10%
Rancho Cordova	39%	54%	6%	1%
Industrial Area	41%	54%	4%	1%
Elk Grove / Laguna	22%	67%	9%	2%
Galt	37%	54%	7%	3%
S. Natomas / Elverta	51%	44%	4%	1%
N. Natomas	36%	54%	7%	3%
AFB	61%	33%	7%	0%
Other Area	49%	47%	4%	1%

9.2 Roofing Information

9.2.1 Roofing Materials

An extensive search was made for detailed information on roofing products used on new and existing buildings. The best data available are from the National Roofing Contractors Association (NRCA). NRCA produce an annual market survey of roofing materials used for residential and commercial projects, broken down by region of the country. Table 9-4 details the materials used for residential new construction and reroofing projects in the West[55] in 1994. The table shows the percentage breakout of roof types for new construction and reroofing, and the weighted average based on dollar volume.[56] Figure 9-1 graphically shows the distribution of roofing materials.

This shows that asphalt shingles are used for the majority of both new construction and reroofing jobs, or 53% of the time. Low-slope materials, consisting of built-up roofs (such as tar and gravel, and other bitumen-type roofs) are the next most common, at 23.8%. Tile roofs make up close to 12% of the roofs in new construction and close to 8% overall. Metal roofs make up

[55] The NRCA breaks out the country into four regions: Northeast, Midwest, South, and West. "West" includes 13 states: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

[56] The dollar volume is based on the value of all roofing contracts, which includes labor, material, and profit. The NRCA information does not break out the information further into average dollar value per job, which would result in the number of jobs per year.

6.4% of roofs. Other types of roof materials are used for 4% of roofs, with wood shingles / shakes on just over 3% of roofs.

In evaluating the historical trend for roofing materials over the last 6 years, the breakdown of material use has been very consistent. Thus it can be assumed that both older homes and newer homes are fairly evenly distributed in roofing materials used in terms of new and reroofing materials.

Table 9-4. Residential Roofing Market for Western Region (%).

	New Construction	**Reroofing**
Asphalt Shingles	53.0	52.9
Low Slope Materials	20.4	24.6
Tile	11.9	6.7
Metal	7.3	6.2
Wood Shingles	4.1	3.3
Slate	0.8	2.0
Other	2.5	4.3
TOTAL	100.0	100.0

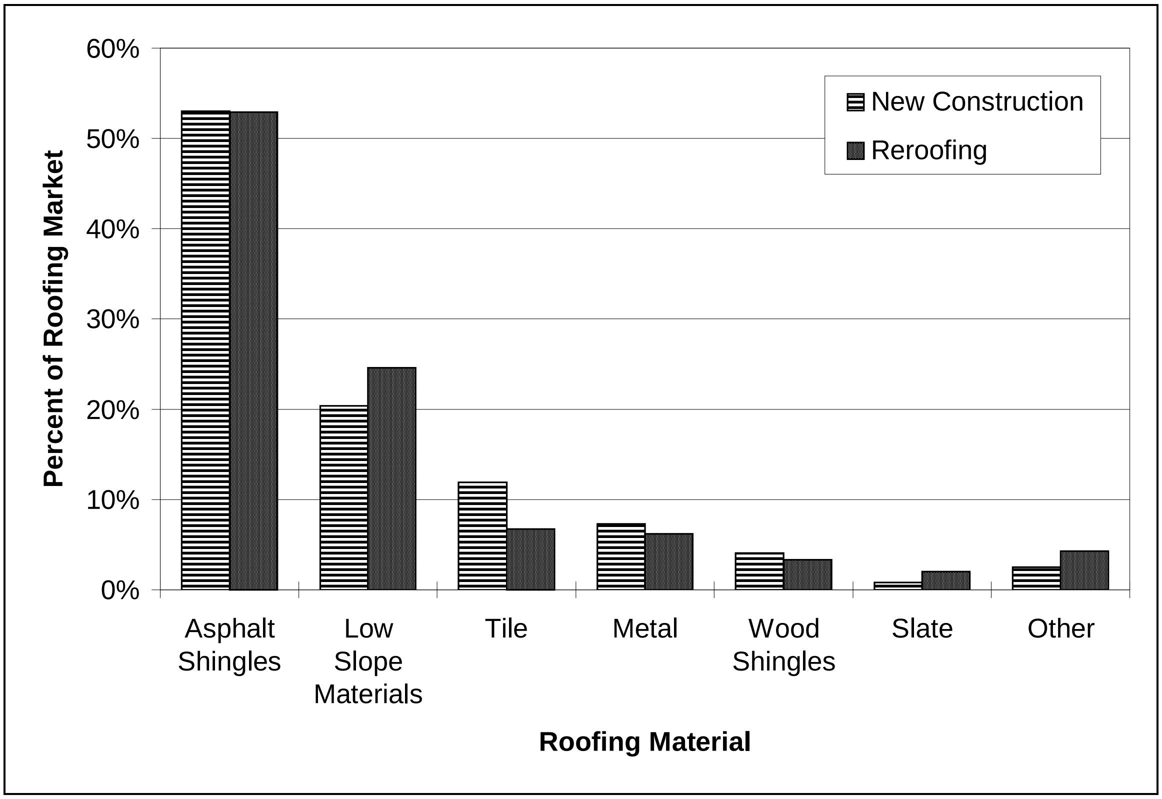


Figure 9-1. Residential roofing market for western region of U.S.

9.2.2 Roofing Materials and PV Retrofit Applications

SMUD has found asphalt shingles to be the easiest and preferred roof type for a PV Pioneer roof installation. Fortunately, these make up the majority of roofs in the Sacramento area. SMUD has found that low-slope roofs require greater care in a PV retrofit application. Care needs to be taken to not penetrate the roof membrane with the gravel when walking on the roof. Although it is more difficult, PV retrofit applications can be made on tile roofs by removing the tiles and installing a composition roof under the PV. Metal roofs have also been found to be acceptable for retrofit PV applications.

9.2.3 Roofing Materials and Building-Integrated PV Applications

This is an area in which SMUD does not have as much experience. However, if the PV is designed into the roof before the roof is installed, any type of roof surface can be used.

9.2.4 Aerial Photograph Evaluation

An aerial photograph of a section in the Elk Grove / Laguna area is on the following page. This is Section 28, T 7 N, R 5 E, MDB&M, covering a one square mile area. The scale of the photograph is 1" = 200 '.

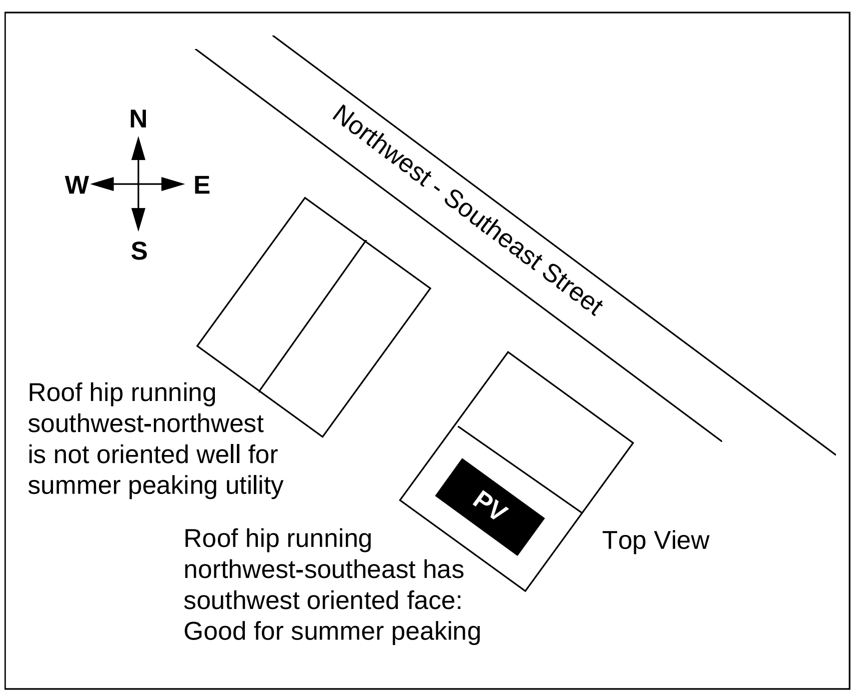
9.2.4.1 ROOF ORIENTATION

The photograph shows that when the homes are on a north-south running street, or an east-west running street, all of the homes will have either a south-facing or a west-facing section of roof that can accommodate a PV system. However, when the homes are on a curved street, or a street running southwest-northeast or northwest-southeast, only about 50% of the homes will have a properly oriented roof depending on how the roof hip is oriented. If the hip is northwest-southeast, there will be a section of the roof that is facing southwest which is usable for a PV system. However, if the hip is running southwest-northeast, the roof faces are southeast and northwest, which are not ideal for summer peaking utilities like the District. This is shown in the Figure 7 below.

Seven of the subdivisions on this photo were evaluated to determine how many of the homes were oriented in the proper direction. These are noted on the photo by two numbers. The top number is how many homes have roof faces oriented in the south to west direction, and the bottom number is the total number of homes in the subdivision. The totals from all seven subdivisions show 432 homes with south to west oriented roofs, out of a total of 657, or 66%.

9.2.4.2 ROOF SQUARE FOOTAGE

The photos show that many of the homes that are oriented properly for PV have roof faces of at least 400 square feet. However, some of the homes have pop-outs on the roof faces and other architecturally interesting roof, which reduce the unshaded square footage available for PV. Of all the homes, of which 66% are oriented correctly for PV, only 50% have enough roof square footage to accommodate a 4 kW system. Of the remaining 16%, half of these could probably accommodate a 3 kW system and half a 2 kW system.



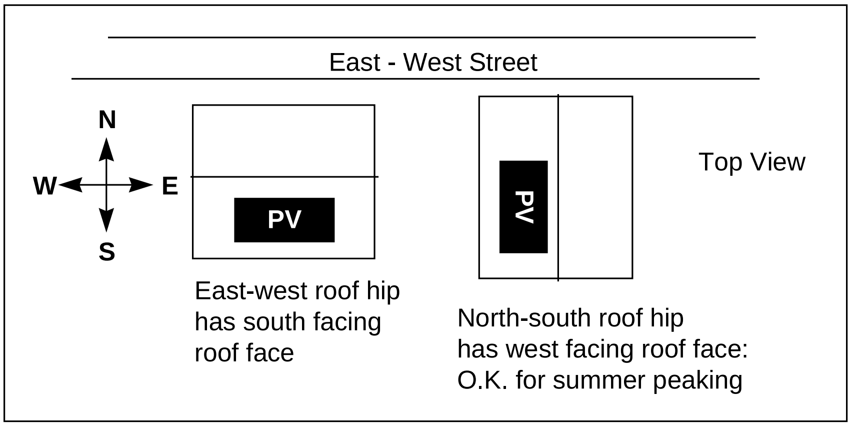


Figure 9-2. Roof orientation impacts on siting PV.

9.3 SACRAMENTO MARKET POTENTIAL

The market potential for Sacramento County is looked at in two different ways. The first is the potential number of households with roofs that can accommodate PV systems under SMUD's PV Pioneers program. Household income is not a factor in determining the size of this market since SMUD pays for the entire PV system. To establish an upper bound, it is assumed that the minimal amount extra that SMUD currently charges to be a PV Pioneer can be paid by all households, and that eventually SMUD will do away with the PV Pioneer surcharge.

In a meeting with Dave Collier of SMUD, he indicated that Folsom and Rancho Murieta were not the best places for retrofit solar installations because of the high percentage of tile roofs. Additionally, Downtown and Pocket were less desirable because of tile and wood shake roofs. Rancho Cordova / Citrus Heights is mixed because of numerous trees which produce shading. The best areas are Elk Grove, Elverta / Natomas, Galt, and Antelope. He also indicated that they use homes with roofs facing between due south and due west. This helps SMUD meet their peak afternoon loads and also increases the pool of homes which meet the proper orientation criteria.

9.3.1 Current PV Pioneer Potential

Table 9-5 shows the calculation of the total PV Pioneer capacity potential in 1996 in the District's service area. The number of households in each planning area is aggregated by the roofing types for that area. An assumption is then made about the percentage of homes that are properly oriented for PV in that area. As discussed in the aerial photos section, it is assumed that 50% of the homes will have a 400 square feet of a properly oriented roof surface for PV, which could accommodate a 4 kW PV retrofit PV system; 8% of the homes have a properly oriented roof with 300 square feet available (for a 3 kW system); and 8% of the homes have a properly oriented roof with 200 square feet available (for a 2 kW system).

Two limiting factors are then applied. The first is an "ease of installation factor" based on the roof type, ranging between 0 and 1. For example, asphalt shingles receive a factor of 1, since they are the easiest and preferred roof for installing a retrofit PV pioneer system. On the other hand, tile roofs receive an installation factor of 0.2, since they are more complicated for installing a system. The second limiting factor is a "shading factor for the area" based on the presence of mature, tall trees that may shade a PV system. This factor also ranges between 0 and 1. For example, in Elk Grove / Laguna, the factor is 1, since this is a new growth area without a number of old trees. On the other hand, Downtown has a factor of 0.1 due to the high probability of shading due to mature tall trees.

The total PV Pioneer potential in kilowatts is then calculated as follows:

Total Kilowatts for Area for Roof Type =

$$H \times IF \times SF \times [(O \times kW)_4 + (O \times kW)_3 + (O \times kW)_2]$$, where

H	=	Households in Area with Given Roof Type
IF	=	Ease of Installation Factor
SF	=	Shading Factor for Area
O_i	=	Percent of Homes Properly Oriented with (i x 100) available square feet of roof space
kW_i	=	Number of kilowatts (i) Roof Can Accommodate

The results show a potential for 385 MW of PV Pioneer residential installations in Sacramento County as shown in Table 9-5 below. The greatest potential is on homes in the Carmichael / Citrus Heights area, with a potential of 147 MW of PV, of which 105 MW is on asphalt shingled homes.

Table 9-5. Current Potential MW of PV Pioneer Installations for SMUD

Distribution Planning Area	**MW Potential**
AFB	<1
Antelope	13
Carmichael / Citrus Heights	147
Downtown	6
Elk Grove / Laguna	37
Folsom	12
Galt	13
Industrial Area	6
N Natomas	4
Other Area	31
Pocket	15
Rancho Cordova	31
Rancho Murieta	3
S Natomas / Elverta	66
TOTAL	**385**

9.3.2 Future PV Pioneer Potential

The potential for residential PV pioneers will increase as more households are added within the SMUD territory. The SMUD 1995 Integrated Resource Plan projects a growth rate of 1.9% per year, which will bring the number of residential customers to 462,500 in the year 2000, and 508,000 in the year 2005. This same growth rate can be applied to the total potential megawatts of residential PV pioneers, resulting in the following projection shown in Table 9-6.

Table 9-6. Future Potential MW of PV Pioneer Installations for SMUD

Distribution Planning Area	Potential in 1996 (MW)	Potential in 2000 (MW)	Potential in 2005 (MW)
AFB	< 1	< 1	< 2
Antelope	13	14	15
Carmichael / Citrus Hts	147	158	174
Downtown	6	6	7
Elk Grove / Laguna	37	40	44
Folsom	12	13	14
Galt	13	14	15
Industrial Area	6	6	7
N Natomas	4	4	5
Other Area	31	33	37
Pocket	15	16	18
Rancho Cordova	31	33	37
Rancho Murieta	3	3	4
S Natomas / Elverta	66	71	78
TOTAL	**385**	**412**	**457**

9.4 Customer-Owned Potential

The determination of the customer-owned upper bound market potential for PV systems follows a similar analysis to the SMUD-owned with a few variations. First, the number of households for each SMUD area is divided into 4 marginal tax brackets based on the census tract data. These marginal tax brackets are 15%, 28%, 31%, and 36%. The number of potential households are reduced by applying a limiting factor of owner-occupied homes. It is assumed that the most likely customer-owned systems will be installed by those people who own their own home. The overall average of owner-occupied housing in Sacramento County from the 1990 census is 56.6%.

Tables contained in the appendix show the total potential number of roofs in Sacramento in 1996 that could be used for customer-owned systems broken into SMUD service territory area. The number of households in each area is split into the roofing types for that area and by tax bracket.

An assumption is then made about the percentage of homes that are properly oriented for PV in that area. As discussed in the aerial photos section, it is assumed that 50% of the homes will have a 400 square feet of a properly oriented roof surface for PV, which could accommodate a 4 kW PV retrofit PV system; 8% of the homes have a properly oriented roof with 300 square feet available (for a 3 kW system); and 8% of the homes have a properly oriented roof with 200 square feet available (for a 2 kW system).

Two limiting factors are then applied. The first is an "ease of installation factor" based on the roof type, ranging between 0 and 1. For example, asphalt shingles receive a factor of 1, since they are the easiest and preferred roof for installing a retrofit PV pioneer system. On the other hand, tile roofs receive an installation factor of 0.2, since they are more complicated for installing a system. The second limiting factor is a "shading factor for the area" based on the presence of mature, tall trees that may shade a PV system. This factor also ranges between 0 and 1. For example, in Elk Grove / Laguna, the factor is 1, since this is a new growth area without a number of old trees. On the other hand, Downtown has a factor of 0.1 due to the high probability of shading due to mature tall trees.

The total solar potential in kilowatts is then calculated as follows:

Total Kilowatts for Area for Roof Type =

$$H \times IF \times SF \times [(O \times kW)_4 + (O \times kW)_3 + (O \times kW)_2], \text{ where}$$

H	=	Households in Area with Given Roof Type
IF	=	Ease of Installation Factor
SF	=	Shading Factor for Area
O_i	=	Percent of Homes Properly Oriented with (i x 100) available square feet of roof space
kW_i	=	Number of kilowatts (i) Roof Can Accommodate

The results show a potential for 219 megawatts of customer-owned PV potential as shown in detail in tables contained in the appendix. The majority of these megawatts fall into the 15% and 28% marginal income tax bracket. Only 17 megawatts fall into the two highest marginal tax brackets (See Table 9-7). For further discussion regarding the upper bound market of customer-owned PV systems, see The Market for Utility- and Customer-Owned PV section.

Table 9-7. Current Total Potential MW Customer-Owned PV for SMUD

	Marginal Tax Bracket			
Distribution Planning Area	15%	28%	31%	36%
AFB	< 1	< 1	< 1	< 1
Antelope	2	5	< 1	< 1
Carmichael / Citrus Heights	34	42	5	2
Downtown	2	1	< 1	< 1
Elk Grove / Laguna	5	14	2	0.5
Folsom	2	4	1	< 1
Galt	3	4	0.5	0.25
Industrial Area	1	2	< 1	< 1
N Natomas	1	1	< 1	< 1
Other Area	9	8	1	< 1
Pocket	4	4	0.5	< 1
Rancho Cordova	7	10	1	0.25
Rancho Murieta	< 1	1	< 1	< 1
S Natomas / Elverta	19	16	2	0.25
TOTAL	**89**	**112**	**13**	**4**

(Columns totals are rounded)

9.5 FUTURE CUSTOMER-OWNED POTENTIAL

Making the same assumptions as the PV Pioneer analysis, the future customer-owned potential would grow by 7.8% between 1996 and 2000, and by another 9.8% beyond 2000 to the year 2005. This would put the total customer-owned potential at 234 MW in the year 2000, and 257 MW in the year 2005.

10.References

Aitken, Donald W., "Sustained Orderly Development of the Solar-Electric Technologies", Solar Today, American Solar Energy Society, Boulder, CO, Vol. 6, No. 3, June 1992.

Awerbuch, Shimon, "The Surprising Role of Risk in IRP", *Electricity Journal*, April 1993.

California Energy Commission, *1994 Electricity Report*, November 1995.

California Franchise Tax Board, 1994 Annual Report (1993 Taxable Year).

California Photovoltaics for Utilities Working Group, *California Photovoltaics for Utilities Commercialization Plan: Proactive Leadership to Stimulate Early Adoption of Photovoltaics Through Sustained Orderly Development*, Sacramento, California, November 1993.

"City and County Plus" Statistical Database, Sacramento, CA, 1996.

Clemer, Steve, *The Economic Impacts of Renewable Energy Use in Wisconsin, Department of Administration*, Division of Energy and Intergovernmental Relations, Wisconsin Energy Bureau, Madison, Wisconsin, April 1994.

Demeter, Christian, *Economic Impacts of a Photovoltaic Module Manufacturing Facility*, United States Department of Energy, Office of Conservation and Renewable Energy, Office of Solar Energy Conversion, Photovoltaic Program, Washington, D.C. May 7, 1992.

Electric Power Research Institute, *Technical Assessment Guide (TAG), Electricity Supply*, EPRI TR-102275-V1R7, Palo Alto, CA, June 1993.

Garver, L. L., "Effective Load Carrying Capability of Generating Units", *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-85, No. 8, pp. 910-918, August 1966.

Geller, Howard, John DeCicco, and Skip Laitner, *Energy Efficiency and Job Creation: The Employment and Income Benefits from Investing in Energy Conserving Technologies,* The American Council for an Energy-Efficient Economy, Washington, D.C., October 1992.

Hoerner, J. Andrew, Alan S. Miller, and Frank Muller, *Promoting Growth and Job Creation Through Emerging Environmental Technologies*, National Commission for Employment Policy, Research Report No. 95-03, Washington, D.C., April 1995.

Hoff, T., "The Value of Photovoltaics: A Utility Perspective", 19th IEEE PV Specialists Conference, New Orleans, Louisiana, May 1987.

Hoff, T., "Calculating Photovoltaics' Value: A Utility Perspective", *IEEE Transactions on Energy Conversion*, Vol. 3, No. 3, pp. 491-495 September 1988.

Hoff, T., Shugar, D.S., and H.J. Wenger, "Economic Determination of Optimal Plant Design For Photovoltaics in the Utility Distribution System", IEEE Photovoltaic Specialists Conference, Las Vegas, Nevada, October 1991.

Hoff, T.E. and H.J. Wenger, *The Value of Distributed Generation: The PVUSA Grid-Support Project Serving Kerman Substation*, Interim Report, April 1994.

Hoff, T., Wenger, H.J., and B.K. Farmer, "The Value of Grid-Support Photovoltaics in Providing Distribution System Voltage Support", Presented at the Solar 94 Conference, American Solar Energy Society, San Jose, California, June 1994.

Hoff, T., and D.S. Shugar, "The Value of Grid-Support Photovoltaics in Reducing Distribution System Losses", Unpublished, July 1994.

Hoff, T., and D.S. Shugar, "The Value of Grid-Support Photovoltaics to Substation Transformers", Unpublished, July 1994.

Hoff, T. E., H. J. Wenger, and B. K. Farmer, "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity," *Energy Policy* 24, 2 (1996), 137-147.

Hoff, T.E, *Integrating Renewable Energy Technologies in the Electric Utility: A Risk Management Approach*, National Renewable Energy Laboratory Report, forthcoming (1996).

Hoff, T. E., *Cost Minimizing Investments Under Uncertainty*, Engineering-Economic Systems Department Dissertation, Stanford University, forthcoming 1996.

Hoymeyer, Olav H., "Solar Energy and Job Creation: Benefits of Photovoltaics in Times of High Unemployment," 1st World Conference on Photovoltaic Energy Conversion, Waikoloa, Hawaii, December 5-9, 1994, 2391-2394.

Internal Revenue Service, 1994 Tax Brackets.

Jensen, T. of Strategies Unlimited, personal communication, January 1996.

Jones, C. of Sacramento Municipal Utility District, personal communication, May 1996.

Jurgens, Kallie, "Northeast Economic Development Picture Begins to Look Brighter," National Real Estate Investor, v33n11, October 1991, 87-91.

Laitner, Skip, Marshall Goldberg, Michael Sheehan, Marc Baldwin, *Environment and Jobs: The Employment Impact of Federal Environmental Investments*, National Commission for Employment Policy, Research Report No. 95-02, Washington, D.C., April 1995.

Meeting with Dave Collier (SMUD), Jan Pepper (Enertron) and Howard Wenger (PEG) on January 22, 1996.

Nagelhout, Mary, "Rate-Making Treatment of Economic Development Costs," *Public Utilities Fortnightly*, v130n4, August 15, 1992, 32-34.

National Renewable Energy Laboratory, *Solar Radiation Data Manual for Flat-Plate and Concentrating Collectors*, NREL/TP-463-5607, Golden, Colorado, April 1994.

National Renewable Energy Laboratory, *User's Manual for TMY2s: Typical Meteorological Years, Derived from the 1961-1990 National Solar Radiation Data Base*, Bill Marion and Ken Urban, Golden, Colorado, June 1995.

National Roofing Contractors Association
10255 W. Higgins Road, Suite 600
Rosemont, IL 60018-5607
Phone: 708-299-9070
Fax: 708-299-1185
Reports:

- NRCA Annual Market Survey, Historical Review
- National Roofing Contractors Association, 1994-1995 Annual Market Survey
- Kane, Karen, "NRCA's Market Survey indicates Decline in Roofing Business", Professional Roofer, March 1995, pp. 22 - 26.
- NRCA Glossary of Terms
- Total Roofing Market, 1992 vs. 1993 vs. 1994 vs. 1995 (projected)

Osborn, Donald E. and David E. Collier, "The Development and Performance of SMUD Grid-Connected Photovoltaic Projects," NREL Photovoltaic Performance and Reliability Workshop, Golden, Colorado, September 1995.

Osborn, Donald E. and David E. Collier, "Utility Grid-Connected Photovoltaic Distributed Power Systems", National Solar Energy Conference, ASES Solar 96, Asheville, NC, April 1996.

Pace University Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Prepared for New York State Energy Research and Development Authority and the United States Department of Energy, Oceana Publications, Inc., New York, 1991.

Pacific Gas & Electric Company, *Resource*, San Francisco, California, 1992.

Price, H., *SMUD Combined Cycle Power Tower Study, Phase I Draft Report*, National Renewable Energy Laboratory, May 1995.

Powers, Marie, “Utilities Stepping Up Economic Development Efforts : Site Selection Services Benefit Developers, Tenants,” National Real Estate Investor, v31n12, November 1989, 97-102.

PVUSA 1994 Progress Report, prepared by PVUSA Project Staff, Pacific Gas & Electric Company, San Ramon, California, June 1995.

PVUSA 1995 Progress Report, prepared by PVUSA Project Staff, Pacific Gas & Electric Company, San Ramon, California, forthcoming 1996.

Roberts, Peter A., et. al., *An Assessment of the Regional Economic and Employment Impacts of the Commercialization of Renewable Technologies*, National Renewable Energy Laboratory, Golden, CO, Contract No. BC-2-11194-0, June 27, 1995.

Sacramento Area Council of Governments, 3000 "S" Street, Suite 300, Sacramento, CA 95816. Census data and census tract maps for Sacramento County. (U.S. Bureau of the Census data)

Shugar, D., personal communication, February, 1996.

SMUD, *1995 Integrated Resource Plan: Executive Summary*, February 1995a.

SMUD, *1995 Integrated Resource Plan: Volume I*, February 1995b.

SMUD, *1995 Integrated Resource Plan: Volume II Technical Appendix*, March 1995c.

SMUD, *1995 Integrated Resource Plan: Volume III Implementation Plan,* April 1995d.

SMUD, *1995 Integrated Resource Plan: Volume IV Public Process*, May 1995e.

SMUD, *1995 Integrated Resource Plan: Volume IV Appendix A*, May 1995f.

SMUD, *1995 Integrated Resource Plan: Volume IV Appendix B*, May 1995g.

SMUD, *1995 Integrated Resource Plan: Volume IV Appendix C and D*, May 1995h.

SMUD, *1995 Marginal Cost Update, Draft, Resource Planning and Evaluation,* August 1995i.

SMUD, *Five Year Distribution System Business Plan: Managing Our Core Business 1996-2000, Volume I: Summary Report*, January 1996a.

SMUD, *Five Year Distribution System Business Plan: Managing Our Core Business 1996-2000, Volume II: Technical Analysis*, January 1996b.

SMUD, "Request for Qualifications No. C96013 for 1996 Photovoltaic Power Systems", February 1996c.

SMUD, "Request for Proposal No. C96026 for Renewable Resources", March 1996d.

Starrs, T., "Overcoming Legal and Institutional Obstacles to Private Investment in Grid-Integrated Solar Electric Buildings: The Case for 'Net Metering'", First International Solar Electric Buildings Conference, Boston, MA, March 1996.

The Solar Letter, The International Newsletter on All Aspects of Renewable Energy, Vol. 6, No. 9, Published by Allan L. Frank Associates, Silver Spring, Maryland, April 1996.

Townsend, T.U., Hutchinson, P.A., Whitaker, C.M., Farmer, B.K., and H.J. Wenger, "A New Performance Index for PV System Analysis", First World Conference on Photovoltaic Energy Conversion, Waikoloa, Hawaii, December 1994.

UPVG, Utility PhotoVoltaic Group, "Request for Proposals - 1995 TEAM-UP Program", Washington, D.C., December 1995.

von Meier, Alexandra, “Manufacturing Energy Requirements and Energy Payback of Crystalline and Amorphous Silicon PV Modules,” Proceedings of the 1994 Annual Conference, American Solar Energy Society, San Jose, CA, June, 1994.

Wenger, H.J., Hoff, T.E., and B.K. Farmer, "Measuring the Value of Distributed Photovoltaic Generation: Final Results of the Kerman Grid-Support Project", First World Conference on Photovoltaic Energy Conversion, Waikoloa, Hawaii, December 1994.

Wenger, H.J. and T.E. Hoff, *The Value of Photovoltaics in the Distribution System: The Kerman Grid-Support Project*, Final Report, Pacific Gas & Electric Company and the U.S. Department of Energy, San Ramon, CA, June 1995a.

Wenger, H.J. and T.E. Hoff, *QuickScreen: A Distributed Resource Planning Tool*, Sandia National Laboratories and the National Renewable Energy Laboratory, U.S. Department of Energy, Albuquerque, NM, June 1995b.

Wenger, H.J. and T.E. Hoff, *Validating QuickScreen, A Distributed Resource Planning Tool*, Distributed Resources 1995: EPRI's First Annual Distributed Resources Conference, Kansas City, MO, August 1995c.

Wenger, H., Hoff, T., and D. Furseth, *QuickScreen Beta Version*, Pacific Energy Group and U.S. Department of Energy, March 1996.

Other Contacts for Residential Rooftop Analysis (Not Directly Referenced in Study)

1. National Association of Home Builders National Research Center
   400 Prince George Blvd.
   Upper Marlboro, MD 20772
   Phone: 301-249-4000

2. U.S. Bureau of the Census
   · American Housing Survey
   · Dicennial Census of Housing
   · Population Division
   · State Data Center
   · Income Statistics

3. Asphalt Roofing Manufacturers Association
   6000 Executive Drive, Suite 201
   Rockville, MD 20852-3803
   Phone: 301-231-9050

4. National Association of Realtors
   430 N. Michigan Avenue
   Chicago, IL 60611
   Phone: 313-329-8200

5. Roofing Industry Educational Institute (RIEI)
   14 Inverness Drive E, Bldg H, Suite 110
   Englewood, CO 80112-5608
   Phone: 303-790-7200

6. Roof Consultants Institute (RCI)
   7424 Chapel Hill Road
   Raleigh, NC 27607
   Phone: 919-859-0742

7. Building Industry Association (BIA) of Sacramento
   John Orr, Executive Director
   Phone: 916-575-1430

Appendices are in Hard Copy Form Only

- Appendix A – District Maps
- Appendix B – QuickScreen Data Sheets and Charts
- Appendix C – Marginal Cost Data
- Appendix D – Rooftop PV Market Potential Tables
- Appendix E – PVGRID™ Sample Output
- Appendix F – Calculating Levelized Benefits and Costs