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FINAL PROJECT REPORT

UTILITY SYSTEM CAPACITY AND CUSTOMER DEMAND VALUE OF PHOTOVOLTAIC

Prepared for: California Energy Commission
Prepared by: Clean Power Research

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Prepared by:

Primary Author(s):
Thomas E. Hoff
Richard Perez

Clean Power Research
Napa, California 94558
and
Albany, New York 12203

Contract Number: 500-00-034

Prepared for:

California Energy Commission

Hassan Mohammed
Project Manager

Linda Spiegel
Office Manager
Energy Generation Research Office

Laurie ten Hope
Deputy Director
RESEARCH AND DEVELOPMENT DIVISION

Robert P. Oglesby
Executive Director

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

- PIER funding efforts are focused on the following RD&D program areas:
- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Utility System Capacity and Customer Demand Value of Photovoltaic is the final report for the SMUD ReGen project (Contract Number 500-00-034), conducted by Clean Power Research. The information from this report contributes to PIER's Renewable Energy Technologies program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 9166544878.

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Abstract

This project analyzed utility values for distributed photovoltaic (PV) resources in the Sacramento Municipal Utility District (SMUD) service territory. Two studies were completed under this project:

- An analysis of PV and load control, or the ability to mitigate end-use load drivers in response to critical load situations.
- An analysis of the value of PV for an electric utility.

The analysis of PV and load control included customer and utility perspectives for PV with load control on commercial buildings as well as theoretical large amounts of PV combined with district load control. The ability for PV to reduce peak load is substantially increased with a modest amount of load control for non-essential applications such as pool pumps and electric water heaters. The study concludes that load control combined with PV increases effective capacity.

The analysis of the value of PV to an electric utility emphasized effective capacity and risk mitigation, as well as justifying customer-owned systems. It found that PV's ability to reduce peak-period demand is high, with schools and office buildings potentially obtaining a reduction in peak-period electrical demand equal to 80 percent of the PV system's rated peak output. The benefits that SMUD receives from PV are favorably affected by customer ownership. Energy value, transmission and distribution (T&D) system deferral value, risk mitigation values, environmental benefits, governmental incentives, and new business opportunities help to economically justify PV as a distributed energy resource.

The aggregate benefits to PV system owners and their utility companies of properly designed and optimized installations can exceed even the relatively high prices of those systems installed in 2004.

Keywords: Photovoltaics, distributed power, distributed energy resource, PV, effective capacity, effective load carrying capability, total storage utilization.

Executive Summary

Introduction

This report summarizes the results of two tasks undertaken for the Sacramento Municipal Utility District (SMUD) under its Public Interest Energy Research Program agreement with the California Energy Commission by Richard Perez of the Atmospheric Sciences Research Center, Albany, New York, and Tom Hoff of Clean Power Research in Napa, California. The results include:

- Customer and utility benefits for commercial buildings with photovoltaic (PV) and associated load control.
- Theoretical benefits to the utility of large amounts of commercial-sector PV, implemented with load control to achieve complete leveling of the electrical load profile, minimizing spikes in electrical load.
- The value of PV for the electric utility, emphasizing effective capacity and risk reduction.

Project Objectives

The primary objectives of this project were:

- To measure the effective capacity of customer-sited PV installations as a function of customer type, PV-system layout and size, and to determine how effective capacity could be enhanced with the usage of load control strategies.
- To compare the costs and benefits of utility and customer PV ownership strategies.

Project Outcomes and Conclusions

Effective Capacity and Solar Load Control

Effective capacity is a measure of the availability of a generating resource, such as PV, at the time of the utility's peak demand. Effective capacity can help to economically justify distributed PV to an electric utility, such as SMUD, that has a large summer peak-period demand for electricity. In this study, the effective capacity for PV was determined for a small sample of SMUD's large customers, including a health care facility, a school, a retail building, and an office building. In addition, the effective capacity for PV was determined for the entire SMUD system. Actual building/utility load data and PV generation data were used for this analysis.

Effective capacity was quantified using three complementary measures:

- The effective load carrying capability, which is the probability of a customer's peak load reduction using PV.
- The minimum buffer energy storage, which is the lowest level of stored energy or load shedding necessary to supplement PV output on the worst day, so as to insure that peak load reduction is equal to installed PV capacity.

- Total storage utilization, which represents the cumulative amount of load shedding necessary over a given period of time (e.g., a billing cycle) to guarantee a load reduction equal to PV-installed capacity.

Minimum buffer energy storage and total storage utilization are worst case parameters that help to answer the question: How much backup energy, stored energy and/or load shedding would be needed, in addition to PV, to guarantee firm peak load reduction?

For each building analyzed, both stationary PV and sun-tracking PV were considered, with relative sizes ranging from 2 percent to 20 percent of the building peak load they would theoretically serve.

The highest effective capacities were found for customers with summer loads peaking early in the day: Office buildings and schools. Effective capacity decreases with increasing PV load penetration but remains significant for all customers investigated up to penetration levels of 20 percent. For example, at 20 percent penetration (representing about 600 megawatts [MW] of PV for the entire SMUD system), the effective capacity would be almost 60 percent. Thus 600 MW of PV would effectively reduce SMUD's peak by about 360 MW.

Sun-tracking PV was found to yield the highest effective capacity in all cases considered. For stationary geometries, the best orientation was found to be a low-tilting surface facing southwest. For the entire SMUD system, slightly better results were achieved using a higher array tilt because of the utility's late-in–the-day system peak. For facilities with load peaks that occurred early in the afternoon, such as schools, better results were obtained with a due-south orientation.

Theoretically combining load control or energy storage strategies with PV was also investigated. It was found that effective capacity can be substantially increased with the use of modest amounts of on-site storage or load control. Achieving the same peak load reduction without PV would require considerably more storage and/or end-user load curtailment. For the hospital analyzed in the study, achieving 10 percent peak-load reduction would require almost 60,000 kilowatt-hours (kWh) per year of load curtailment. With 10 percent PV penetration, guaranteeing a firm 10 percent peak load reduction would require only 1,100 kWh of load control per year.

Extrapolating PV with load control to the entire SMUD system, with 10 percent PV capacity penetration for SMUD in 2001, 104 MW of direct load control provides a firm 249 MW peak reduction from PV. The periods needed for load control are substantially reduced when load control is combined with PV. The one-day draw of load control needed with PV is 1.3 hours (323 MWh), without PV it is 4.1 hours (1,020 MWh).

PV Ownership Strategy Task

This task compared, for SMUD, all of the benefits and costs associated with the installation and operation of PV systems owned either by SMUD or by its customers. Technically, the effective capacity and energy yield of a dispersed PV resource and its impact on the SMUD load do not depend upon whether the resource is deployed on the user-side or on the utility side of the meter. Economically, the difference can be significant.

Approach: All benefits and costs associated with either customer PV ownership or SMUD ownership were systematically identified and quantified. The benefits to SMUD include:

- Avoided energy generation.
- Transmission and distribution deferral.
- Electricity price risk mitigation.
- Environmental benefits.
- Governmental incentives.
- New business opportunities from the sale and installation of PV equipment.

The system costs to the district include capital costs to SMUD, operation and maintenance costs, and lost revenues.

Results: The benefits of PV ownership to SMUD ranged from $1,300 to $6,800 per installed kW of PV depending upon assumptions. The most influential factors were, in order:

- The value of new business opportunities ($0 to $2,700);
- The value of government incentives ($0 to $1,600); and
- The estimated environmental value ($40 to $1,040).

PV system costs depend greatly upon ownership. Considering, for instance, a 2 megawatt (MW) PV deployment, SMUD ownership would amount to costs of about $13 million, while the cost of customer ownership to SMUD would range from $2.5 million to $14 million. The range in costs to SMUD primarily depends upon PV system ownership, the availability of Energy Commission buydown funds and the treatment of lost revenue.

Benefits to California

The results of this work are relevant to other utilities in California because the issues defining the effective capacity and the value of PV for SMUD (solar resource, air-conditioning loads being major cause of peak demand, capacity constraints, and load growth) are also relevant to most major California electric utility companies. Those utilities with weather conditions similar to Sacramento's cloudless summers can benefit from high effective capacities, and more beneficial load control if teamed with PV. Utility ownership versus customer ownership of PV systems depends on the individual utility handling of the various variables for value and costs of systems. This research outlines those variables for SMUD and gives a process for other electric utilities to follow.

1.0 Introduction

1.1 Background

Summer electrical demand is a concern to the Sacramento Municipal Utility District (SMUD) because of peak generation availability, price, and environmental quality, and because of the stresses and fatigue imposed on the transmission and distribution (T&D) system. One of the approaches that SMUD may use to address this concern is the use of dispersed, customer-sited photovoltaic (PV) generation, provided that generation is reliably available at peak time.

The ability of PV to meet customer demand is an important concern to SMUD because the value of this clean, modular resource can be considerably enhanced if it can be shown that PV generation can provide the equivalent of firm generation capacity.

From a utility standpoint, the effective capacity (EC) of a peaking resource such as PV is defined as the ability of that resource to reduce the utility's peak-period demand for electricity. From a customer standpoint, EC is defined as the ability of the customer-sited resource to reduce customer peak load—thus to reduce demand bills. The first objective of this work was to quantify the EC of PV. Preliminary observations have shown that there is a synergy between PV generation and load control, whereby combining both strategies may be more effective than implementing either independently. Combining PV and load control was also investigated and reported.

Another important factor affecting the value of PV to the district is the question of which ownership strategy (customer or utility) provides the highest net benefits to the district.

1.2 Objectives

The first objective of this project involves analyzing the EC of PV and its maximization through load management for a sample of prospective PV customer host sites.

Because PV is a modular decentralized resource, it can be deployed just as effectively on the customer side of the meter or on the utility side of the meter. Therefore the questions of system ownership and the resulting net benefits to SMUD are important and constitute the second objective of this project.

1.3 Report Organization

The two main objectives of the project were addressed independently by two consultants to SMUD. Richard Perez investigated "PV and Load Control" the EC of PV and its enhancement via load control; and Tom Hoff at Clean Power Research investigated "Value of PV for the Utility," the net benefits of system ownership. Two distinct technical reports, each including a logical summary, introduction, approach, and outcome sections, were produced. Therefore this central report is structured so as to summarize the substance of these reports and refer to the original reports for greater details.

2.0 Project Approach

2.1 PV and Load Control: Determination of Effective Capacity

EC is a measure of a generating resource's availability at times of peak demand. EC may be considered with respect to the demand of a utility system, a subsystem, or an individual customer. In this report EC is determined for the entire SMUD system as well as for a sample of its customers, including health care, retail, office and school buildings, where PV generation could be deployed.

Three complementary measures are used to quantify effective capacity.

1. Effective Load Carrying Capability (ELCC): This is a statistical measure of capacity. For a utility, the ELCC represents the increase in generating capacity that is attributable to the deployed PV capacity. From a customer standpoint, the ELCC represents the probability of peak load reduction. ELCC is quantified in percentage of installed PV capacity (e.g., a 100 kilowatt [kW] PV plant with 50% ELCC would be equivalent to a 50 kW ideally dispatchable resource from a utility standpoint).

2. Minimum Buffer Energy Storage (MBES): This parameter answers the question: How much stored energy—or how much load shedding—would be necessary to supplement PV output on the worst day, so as to insure that peak load reduction is equal to installed PV capacity. As shown in the left image of Figure 1, PV reduces peak ideally. Any mismatch between load and solar peak (i.e., presence of clouds, or late peak) can considerably reduce the effective capacity of PV (center-Figure 1). However a small amount of solar load control—from load shedding and/or on-site storage (right-Figure 1)—can effectively supplement PV and deliver full-capacity credit.

3. The Total Storage Utilization (TSU): This parameter is similar to the MBES but represents the cumulative amount of load shedding necessary over a given period of time (e.g., a billing cycle) to guarantee a load reduction equal to PV installed capacity.

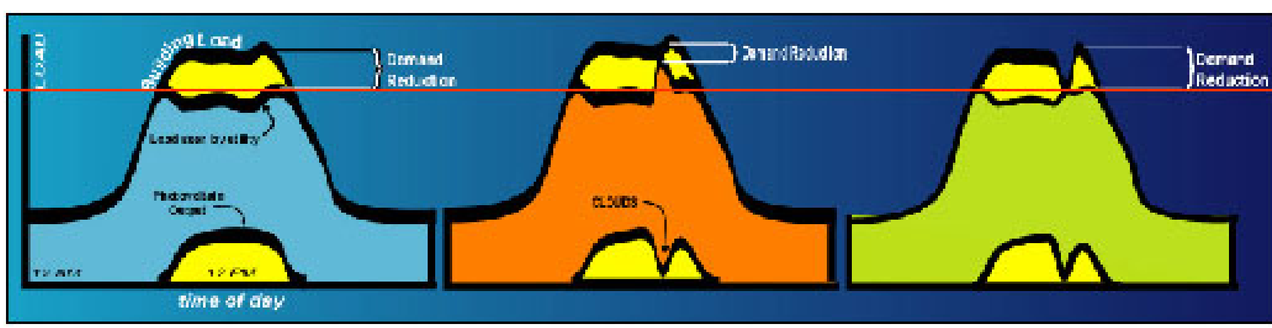

Figure 1: Three load curves illustrate MBES for PV, ideal, with clouds, and load control.

Photo Credit: Thomas Hoff and Richard Perez

These parameters are determined from the analysis of experimental hourly load data and time-coincident PV output data. For each considered utility and customer load, the impact of the relative size and the geometry of PV installation are investigated. PV arrays including both stationary and sun-tracking geometries are considered, with relative sizes ranging from 2% to 20% of the load they are serving.

2.2 Value of PV for the Utility: Determination of Net Benefits of Customer Ownership

The approach used for the determination of net benefits consists of (1) identifying all benefits and costs associated with the construction and operation of PV systems on either the demand side or the customer side of the meter (utility vs. customer ownership) and (2) stacking up all costs and benefits and assessing bottom lines.

All benefits and costs are quantified in terms of life-cycle net present value, including, as appropriate, the definition of high- and low-value ranges.

The benefits included in the analysis are the following:

- Value of energy produced to SMUD
- Deferred transmission and distribution expenses
- Electricity price risk mitigation
- Environmental benefits
- Government incentives
- New business opportunities

Note that all these benefits are independent of system ownership.

On the cost side, two scenarios are defined—one for customer-ownership, and the other for utility-ownership:

- In the case of SMUD ownership, total cost is equal to hardware capital cost, plus operation and maintenance cost, minus public goods funding already earmarked by SMUD and targeted to PV deployment.
- In the case of customer ownership, total cost is equal to hardware capital cost, minus the customer payment to SMUD (this assumes that SMUD builds and sells the PV systems to their customers) minus the earmarked public goods funding, and minus the Energy Commission buydown.[1] Three possibilities are considered for the latter: no buydown, ½ current buydown, and full buydown).

1. SMUD electricity customers would not be eligible for the Energy Commission's buydown funds, since those derive from IOU tariffs, but most are also PG&E gas customers, which qualifies them for the buy-down program.

3.0 Project Outcomes

3.1 PV and Load Control: Determination of Effective Capacity

Figure 2 shows the hourly average July output for various orientations and geometries of PV located in Sacramento.

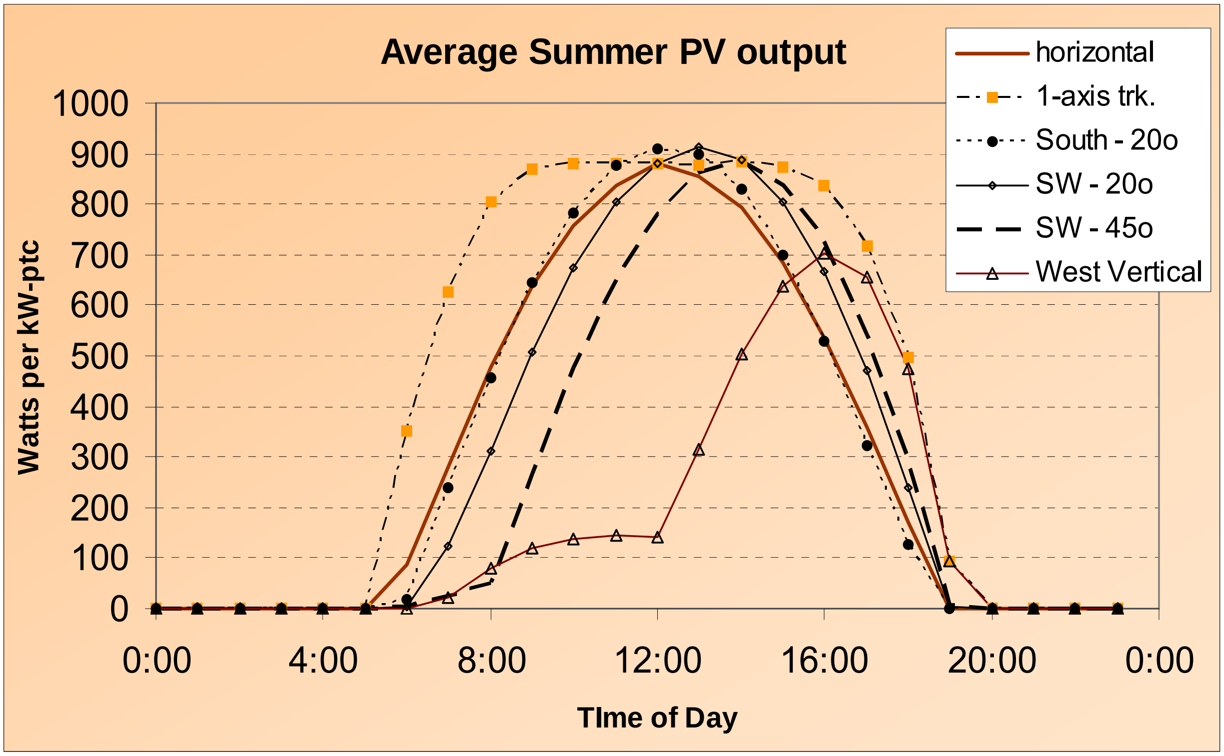

Figure 2: Mean July hourly output for different PV collector orientations in Sacramento

Photo Credit: Thomas Hoff and Richard Perez

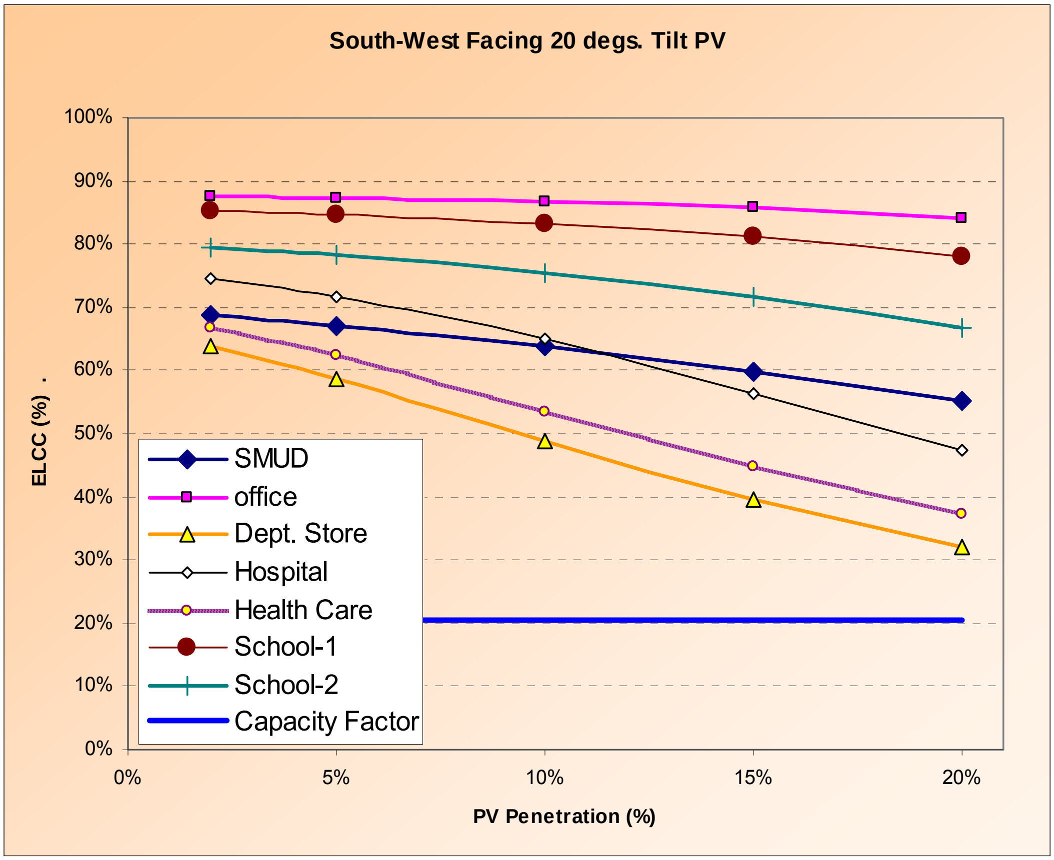

Figure 3: PV ELCC as a function of load penetration for a fixed southwest, 20°-tilt array

Photo Credit: Thomas Hoff and Richard Perez

The EC of PV was quantified using each of the three measures defined in Section 2.1, and determined for each selected load as a function of PV collector geometry and load penetration. A brief overview of the results follows.

- *Effective Load Carrying Capability*: The ELCC of PV is found to be highest for the one-axis tracking geometry, exceeding 80% of rated PV capacity in the best cases, office building and schools, both of which have summer demand peaks early in the day. The EC with respect to the system wide SMUD load is about 70% with tracking geometry. The best fixed collector geometry overall is southwest-facing low tilt. A highlight of the ELCC results is presented in Figure 3. The thick horizontal line represents the actual capacity factor for one-axis tracking PV. The figure shows in comparison to the actual capacity factor the ELCC of a fixed southwest facing low-tilt PV array as a function of its relative size (percentage of customer or SMUD load) for each type of customer and for SMUD. Note that offices, schools, and (to a lesser extent) SMUD, exhibit high ELCC even at large penetration. All these loads have well-defined peaks, early in the day in the best cases. Health-care and retail facilities also exhibit ELCC at less than 5% penetration that is substantially higher than the actual system capacity factor, but the degradation with increasing penetration is more significant in these cases. This is because health-care facilities have a smaller daytime peak relative to their base load than office buildings

- *Minimum Buffer Energy Storage*: In all cases, but particularly for schools and office buildings, the MBES is several times smaller than the amount that would be necessary to achieve the same objective without PV.
- *Total Storage Utilization*: As for the MBES, the required TSU in most investigated cases is considerably reduced by PV installation. For instance, in the least favorable case investigated, a hospital building at 20% PV penetration, there is a five-fold decrease in load control requirements. When considering the better cases, the improvement becomes very significant. For example, compared with 10% PV penetration, it would take SMUD almost 15 times more customer load curtailment without PV to achieve a 10% peak load reduction.

As a highlight of the MBES and TSU results, Table 1 contrasts the load shedding requirements to guarantee 20% peak load reduction on the worst day (MBES) and on a yearly basis (TSU) with and without 20% PV installed. Note the bottom line, showing improvements in the SMUD case of more than 2,000 megawatt-hours (MWh) on the worst day and over 30,000 MWh per year from 560 MW of PV deployment.

Table 1: MBES and TSU to guaranty a peak load reduction of 20%, assuming a PV penetration of 20% and assuming a fixed, southwest-facing PV geometry.

	PV system Size	MBES	MBES-no-PV	TSU	TSU no PV
Office	91 kW	10 kWh	219 kWh	10 kWh	1,483 kWh
Retail	82 kW	293 kWh	684 kWh	13,835 kWh	63,631 kWh
Hospital	422 kW	1,811 kWh	4,305 kWh	63,653 kWh	376,589 kWh
health-Care	181 kW	966 kWh	2,182 kWh	59,922 kWh	238,890 kWh
School-1	144 kW	6 kWh	520 kWh	7 kWh	7,348 kWh
School-2	131 kW	167 kWh	681 kWh	342 kWh	11,817 kWh
SMUD	560 MW	965 MWh	3,144 MWh	3,361 MWh	33,950 MWh

Source: Data collected by Thomas Hoff and Richard Perez

One of the attributes of the MBES metric is that it can be used to estimate the cost of achieving 100% capacity credit with buffer storage. For the SMUD case, this is about $250 to $300 in battery storage per kW of installed PV.

3.1.1 Solar Load Control

Solar load control (SLC) results are summarized in Table 2. The three load control metrics used are: (1) maximum instantaneous SLC capacity draw (maximum load shed or replacement capacity), maximum daily SLC energy requirements (worst day energy need, expressed in hours of shedding or auxiliary generation), and total SLC energy requirements (total yearly need in hours). All cases assume the PV installed capacity to be equal to the desired load reduction. For example, in 2001 at 10% PV penetration (and 10% target load reduction) equal to 249 megawatts (MW), the table shows respectively 42% of 249 MW (104 MW), 1.3 system hours on the worst day, and 1.6 system hours for the year, versus 4.1 hours on the worst day and 14.1 hours for the year of shedding the full 249 MW.

Table 2: Photovoltaic and solar load control metrics for grid penetration ranging from 2% to 25%

			With PV			Without PV	
% Peak load Reduction	Corresponding Capacity (also equals installed PV capacity)	Load Reduction via PV in column 2 w/out load control	Maximum Load-Shed Capacity (% of total load reduction in column 1)	Worst-day SLC Duration (hours)	Annual SLC Duration (hours)	Worst-day Load-Shed Duration (hours)	Annual Load-Shed Duration (hours)
1998							
25%	665	224	66%	3.2	20.1	8.1	91.1
20%	532	211	60%	2.8	12.4	7.4	63.1
15%	399	194	51%	2.3	6.4	6.5	39.8
10%	266	164	38%	1.7	2.6	5.3	20.4
5%	133	93	30%	0.8	0.8	3.7	7.3
2%	53	38	29%	0.4	0.4	2.3	2.8
1999							
25%	690	298	57%	2.9	6.1	7.9	33.3
20%	552	268	51%	2.4	3.3	7.1	21.9
15%	414	219	47%	1.9	2.1	6.1	12.5
10%	276	159	42%	1.4	1.4	4.9	6.3
5%	138	87	37%	0.8	0.8	3.5	3.5
2%	55	37	33%	0.6	0.6	2.1	2.1
2000							
25%	661	202	69%	2.6	20.2	7.1	91.7
20%	529	182	66%	2.2	11.4	6.1	61.2
15%	396	162	59%	1.7	5.8	4.9	36.0
10%	264	142	46%	1.1	2.5	3.8	16.8
5%	132	73	45%	0.7	0.8	2.6	4.6
2%	53	29	45%	0.4	0.4	1.6	1.6
2001							
25%	621	236	62%	2.8	13.5	6.7	64.1
20%	497	222	55%	2.4	8.1	5.9	41.9
15%	373	190	49%	1.9	4.0	5.1	26.6
10%	249	145	42%	1.3	1.6	4.1	14.1
5%	124	72	42%	0.9	0.9	3.0	4.5
2%	50	29	42%	0.6	0.6	1.9	2.0

Source: Data collected by Thomas Hoff and Richard Perez

In other words, extrapolating load control district-wide with 10% PV capacity penetration for SMUD in 2001, 104 MW of direct load control provides a firm 249 MW peak reduction from PV. The periods needed for load control are substantially reduced with PV. One day draw of load control needed with PV is 1.3 hours (323 MWh), without PV it is 4.1 hours (1,020 MWh). The yearly draw needed is 1.6 hours (398 MWh) with PV and 14.1 hours (3,500 MWh) without.

3.1.2 Summary of Outcomes

The outcomes of this project activity include:

- PV's effective capacity was quantified using three complementary measures and found to be significant—much larger than the resource's capacity factor—in all cases investigated.
- Highest effective capacities (in excess of 80%) were found in the case of customers with summer loads peaking early in the day, such as office buildings and schools.
- Effective capacity decreases with PV load penetration but remains significant up to penetration levels of 20%.
- A one-axis tracking PV geometry gives the best results. This geometry may not be suitable everywhere but could be used in open spaces and parking lot applications.
- As an average, the best fixed array geometry is low-tilt, with a southwest orientation. Such a geometry should be suitable in all roof-mounted applications (using PowerLight or RWE Schott-type systems for example). Note, however, that slightly better results for the SMUD-wide load could be achieved with a higher array tilt—because of the district's late peak influenced by residential loading. Early peakers such as schools would benefit from a due-south orientation.
- PV effective capacity can be substantially enhanced with modest amounts of either on-site storage or customer load management (solar load control –SLC). In practice a combination of both strategies would be used to optimize cost and end-user burden.
- Realizing the same capacity results without PV—i.e., using solely storage and load management—would require considerably more storage capacity and end-user burden.

3.2 Value of PV for the Utility: Net Benefits of System Ownership

This section begins with the benefits that have the smallest uncertainty range in economic value. It concludes with the benefits that have the largest range in uncertainty. Each discussion concludes with a quantification of the economic value for low-, medium-, and high-benefit scenarios.

3.2.1 Energy Value

The district has located many of its PV systems on customer premises. As a result, the district needs to produce/procure less electricity for its customers. This benefit is referred to as the energy value. The energy value is the value of the wholesale power savings adjusted to account for a reduction is electricity losses on the generation, transmission, and distribution systems.

PV output by month and period are determined as shown in Figure 4. It is assumed that a 1 kW_{AC} PV system has an 18% capacity factor (1,577 kWh per year). This capacity factor is based on detailed monitoring for an actual 2.9 kW_{AC} system that has been in operation for several years at Hackberry[2] and data on a number of properly operating District residential PV systems.

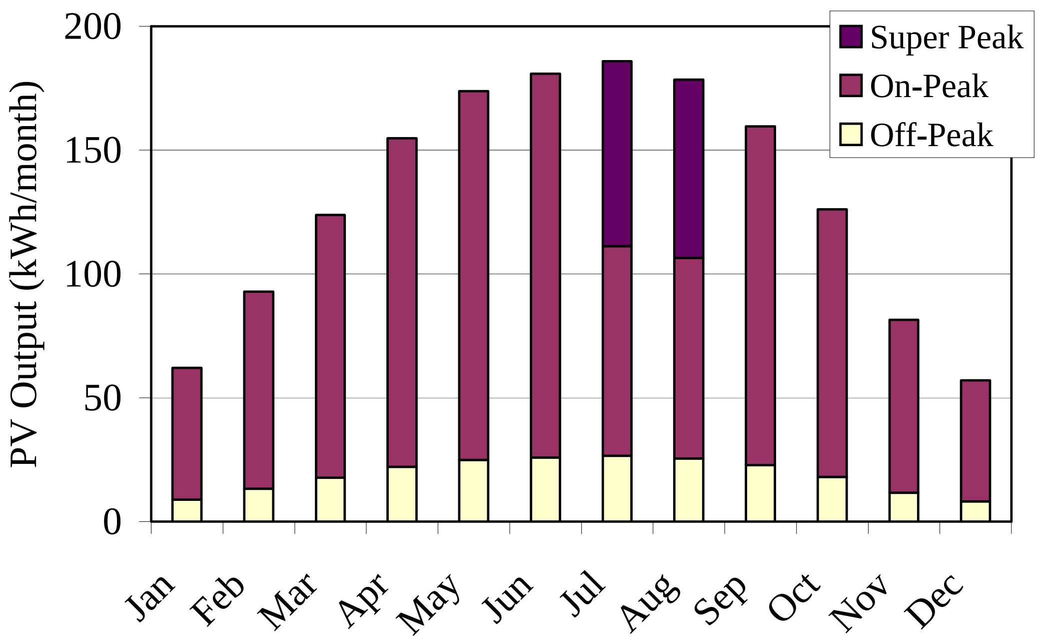

Figure 4: PV output by month and period.

Photo Credit: Thomas Hoff and Richard Perez

3.2.2 Loss Savings

"Loss savings" refers to the system losses that do not occur by virtue of the installed PV. They are presented in the 2000 Marginal Cost Study according to:

- Calculation method (system average, peak incremental, and average incremental).
- System location (transmission, sub-transmission, primary distribution, and secondary distribution).
- Period (summer/winter, and super-peak/on-peak/off-peak).

Loss savings increase the PV system's energy value anywhere from 1% to 15%, depending upon which loss factors are used.[3]

2. The 2.9 kW_{AC} system had a 17.2%, 17.9% and 17.8% capacity factor in 1999, 2000, and 2001, respectively (data available at http://66.92.90.179/SiteAction.asp?SiteName=UPS04). The system is oriented southwest at an 18° tilt. The Clean Power Estimator tool was run to determine the power output for a system facing due south at a 30° tilt; the annual output improved by 5%.

3. See page D-9 of the 2000 Marginal Cost Study for a discussion of the various loss factors.

Calculation Method

The first variable that determines the magnitude of the loss factors is the way that the loss factors were calculated in the 2000 Marginal Cost Study. The options include:

- System average. This equals the total electricity lost divided by the total electricity produced over all hours in the period.
- Peak incremental. This equals the incremental change in losses that occurs during peak loads.
- Average incremental. This equals the incremental change in losses that occurs over all hours in the period.

Average incremental losses is the correct selection since the energy value is associated with an incremental change in the loads over all hours of the year.

System Location

The second variable that determines the magnitude of the loss factors is the location of the energy consumption reduction. Since the District sites the PV systems on the customer's side of the meter, the system location is secondary distribution.

Periods

The third variable that determines the magnitude of the loss factors is the period at which the electricity is produced. This analysis weights the loss factors based on when the PV electricity is produced.

The appropriate loss savings are presented in Figure 5. The definitions of the periods are as follows:

- Summer super peak: July-August weekdays, 1 p.m. to 9 p.m.
- Summer on-peak: June-September weekdays, 7 a.m. to 9 p.m., except on days with the super peak period; and July-August weekends, 1 p.m. to 9 p.m.
- Summer off-peak: June-September, all other hours.
- Winter on-peak: October-February, 9 a.m. to 10 p.m.
- Winter off-peak: October-February, all other hours.
- Spring: March-May, all hours.

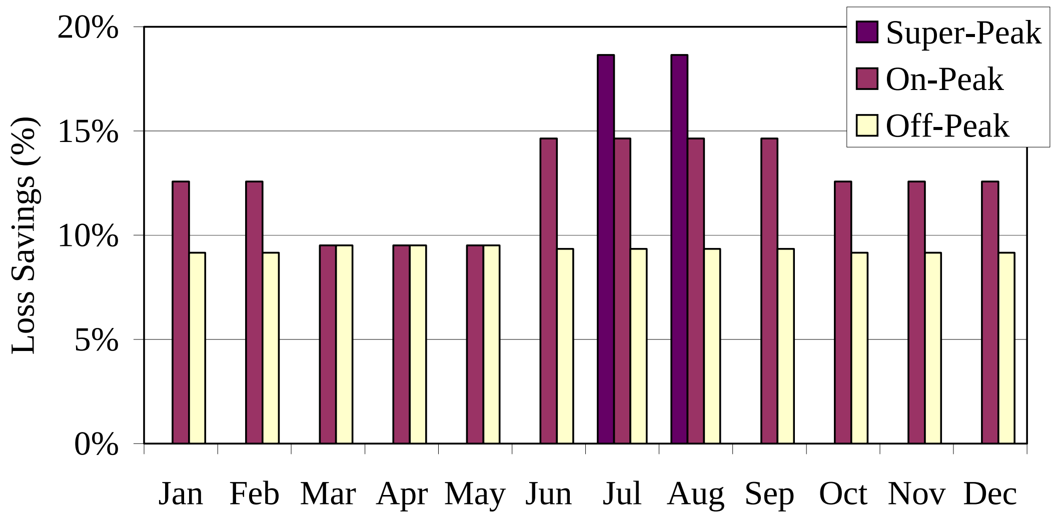

Figure 5: Average incremental loss savings by month and period (secondary distribution)
Photo Credit: Thomas Hoff and Richard Perez

3.2.3 Marginal Costs

Figure 6 presents the 2000 Marginal Cost Study Low Price Forecast. Note that it only contains on-peak and off-peak prices. The super-on-peak electricity produced during the summer months is valued at the on peak prices.

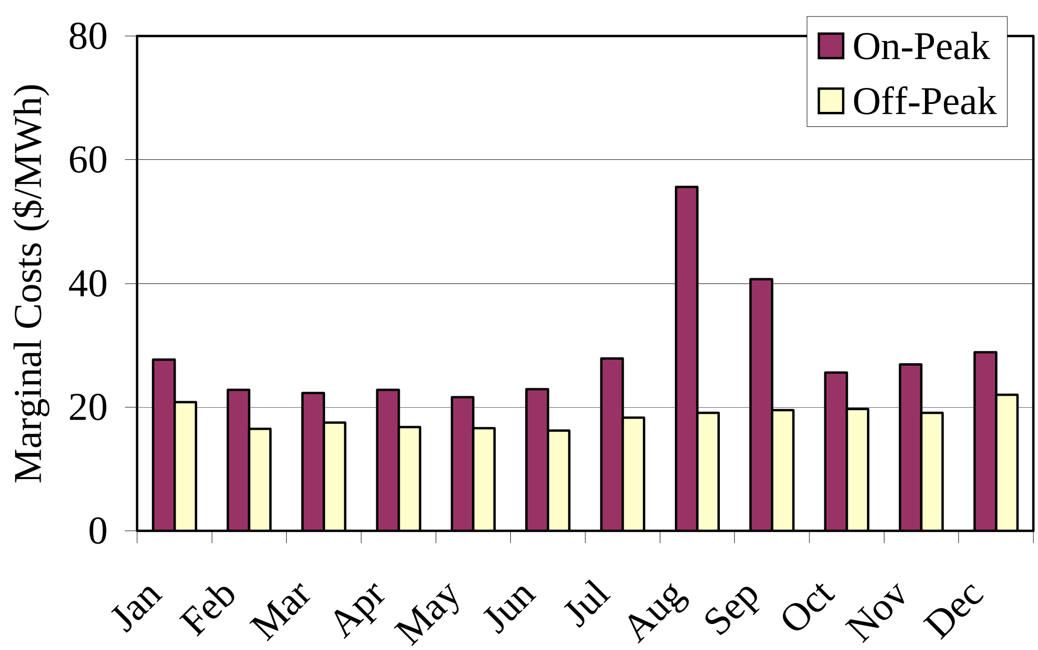

Figure 6: 2002 marginal costs (2000 Marginal Cost Study, Low Price Forecast)
Photo Credit: Thomas Hoff and Richard Perez

3.2.4 Monthly Energy Value

The monthly energy value equals the electricity produced by the PV system by month and period (Figure 4), adjusted for loss savings (Figure 5), times the corresponding marginal cost (Figure 6). The result is presented in Figure 7.

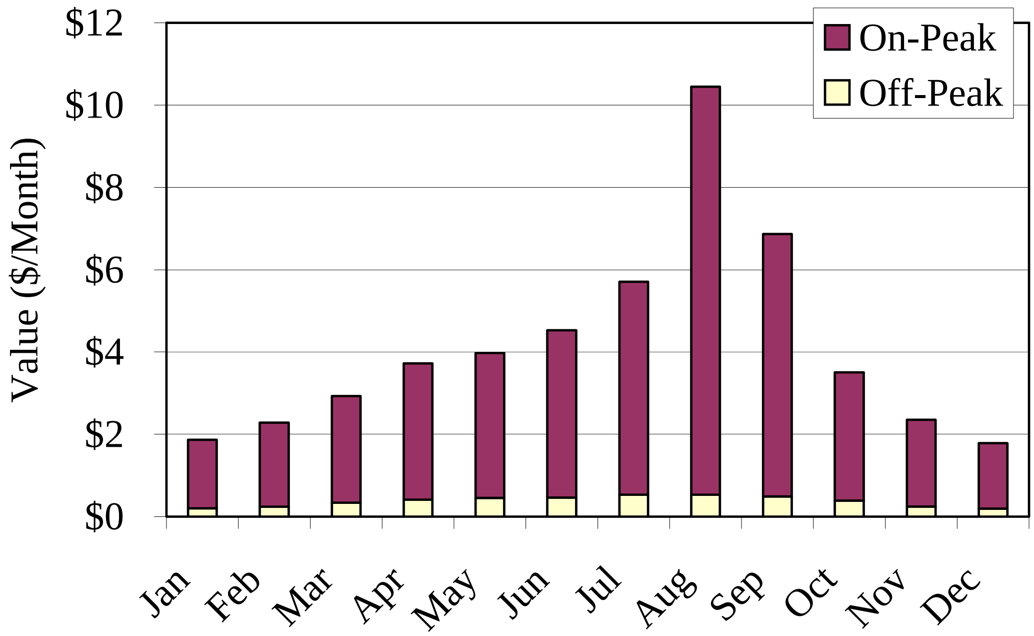

Figure 7. Monthly energy values (2002)

Photo Credit: Thomas Hoff and Richard Perez

3.2.5 Annual Energy Value

The annual energy value equals the sum of the monthly energy values. This process is repeated for each year. The heavy blue line with diamonds represents the result for the 2000 Marginal Cost Study Low Price Forecast in Figure 8. The 2000 Marginal Cost Study only includes results from 2001 to 2010. The PV systems, however, are expected to last 30 years. To calculate the value of the credit after 2010, the annual energy value calculated in 2010 is escalated at a rate of 2 % per year throughout the remainder of the life of the PV system. The result is the heavy blue dashed line in Figure 8.

The process is repeated using the 2000 Marginal Cost Study High Price Forecast. The lighter red lines in Figure 8 represent the result. It is worth noting that there is only a slight difference between the Low Price and High Price Forecasts.

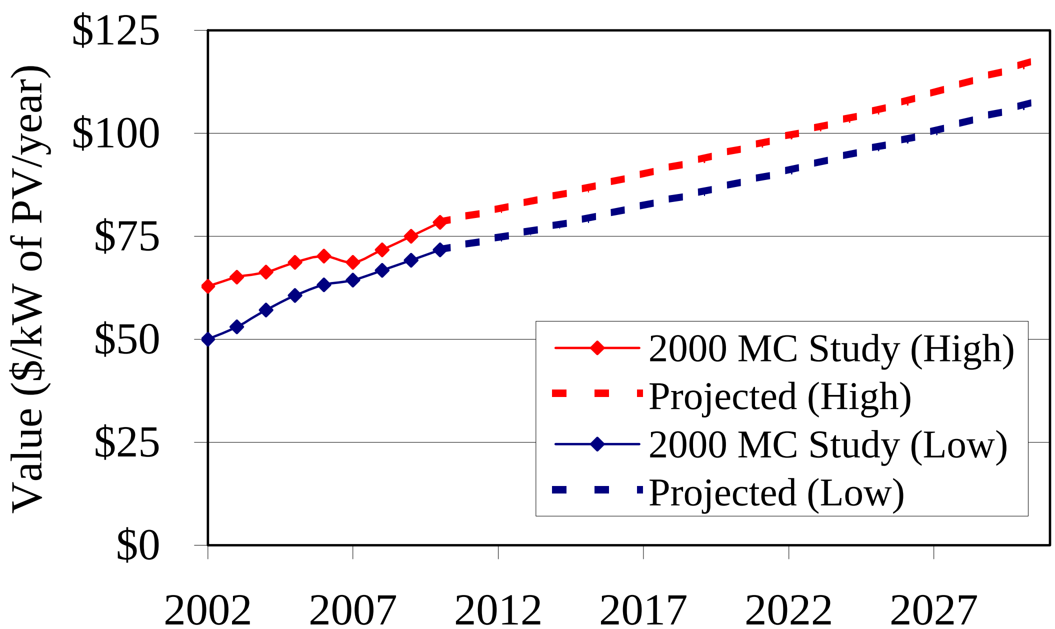

Figure 8: Annual energy value

Photo Credit: Thomas Hoff and Richard Perez

3.2.6 Energy Value

The energy present value equals the sum of the discounted annual energy values. Figure 9 shows the energy present value versus PV system life for the 2000 Marginal Costs. Since PV systems are expected to last 30 years, the figure suggests that the energy value for the low scenario is $1,043 per kW_{AC} of PV (Low Price) and the energy value for the high scenario is $1,158 per kW_{AC} of PV (High Price). The middle scenario is the average of the low and high scenarios; it equals $1,101 per kW_{AC} (Assumptions: 2000 Marginal Cost Study, 18% capacity factor, located in the secondary distribution system, 30-year life).

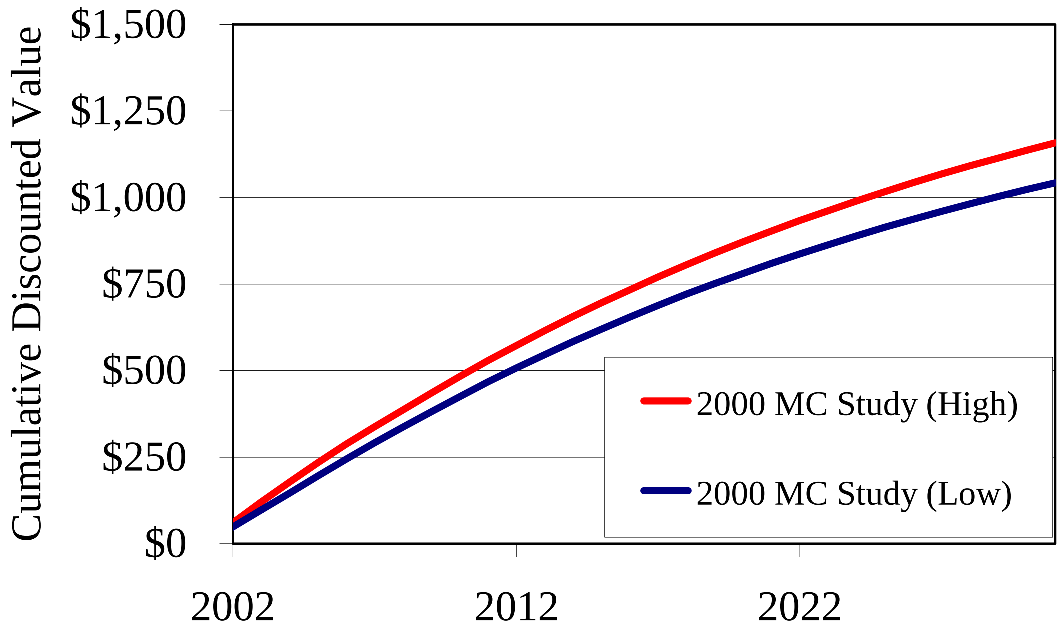

Figure 9: Cumulative discounted energy value versus year ($/kW$_{AC}$ of PV)

Photo Credit: Thomas Hoff and Richard Perez

3.2.7 Transmission and Distribution System Deferral Value

PV systems sited at customer locations are beneficial to the transmission and distribution (T&D) system because less power needs to be delivered over the T&D system. In some cases, this will defer new capital investments in the T&D system and thus reduce the finance charges the district needs to pay for these investments. This is called the T&D deferral value. An extensive analysis on the Deferral Value is included in the original paper. The T&D deferral value equals $71/kW$_{AC}$ for the low scenario and $136/kW$_{AC}$ for the high scenario.

The T&D deferral value is not as high as at some other utilities because the district has dense energy consumption and thus relatively low T&D investment costs. Note that if the district had a high degree of load growth uncertainty, this value would increase.[4]

3.2.8 Risk Mitigation Benefit

Recent events have made it clear that electricity prices can be volatile and uncertain. As long as the PV technically operates as it should and the sun continues to shine, a PV system will provide the utility with a relatively certain stream of power over a long period (30 years). The value of this certainty is the electricity price risk mitigation benefit.

Figure 10 presents the actual and predicted monthly generation credits from April 1998 to December 2001. The figure is based on actual generation prices paid by the District and predicted prices based on the district's marginal costs. The figure emphasizes that there were

4. See T. E. Hoff, "Using Distributed Resources to Manage Risks Caused by Demand Uncertainty," The Energy Journal: Special Issue: 63-83 (January 98) for a discussion of demand uncertainty.

times when the actual monthly generation credit was worth more than 10 times what the marginal costs would have predicted. In fact, the actual monthly generation credit for May 2001 is greater than the predicted annual generation credit for the whole year in 2001. This means that the PV systems actually provided more value to the district in one month than was predicted for one year.

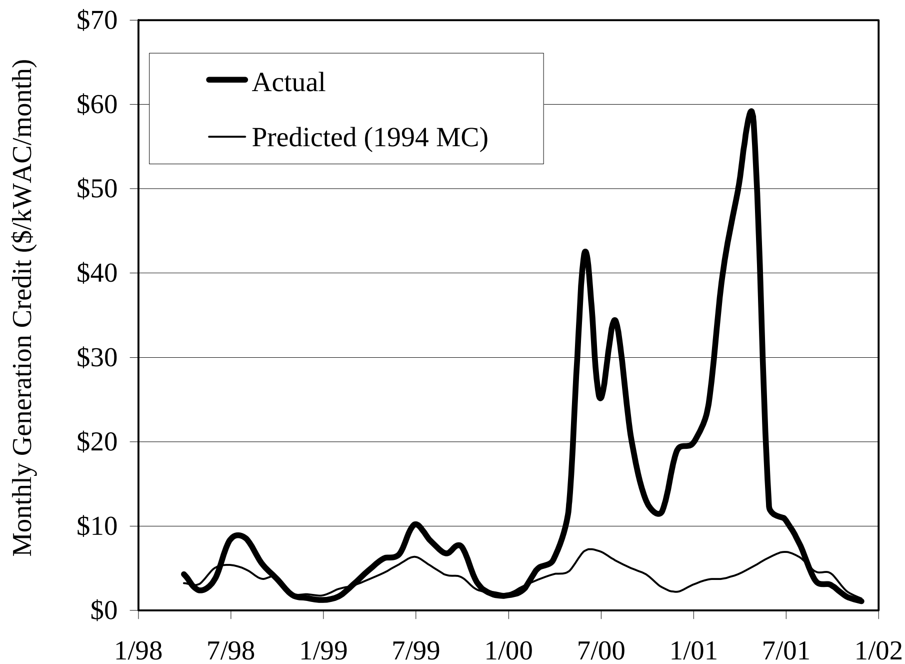

Figure 10: Actual versus predicted monthly generation credit

Photo Credit: Thomas Hoff and Richard Perez

The objective of this project is to assess the market value of PV to the Sacramento Municipal Utility District using the district's data sources. An extensive analysis on the Risk Mitigation is included in the original paper including the use of various SMUD marginal costs studies, the District Resource Plan, Methodology, Portfolio Theory, and Risk-free Asset evaluations. Using these methods suggests that the risk premium ranges from $0.005/kWh to $0.010/kWh. Based on an 18% capacity factor, and 12.5% loss savings, 30-year PV system life, 2% escalation, and 6% discount rate, this translates to a present value of $161/kW$_{AC}$ (low scenario) and $322/kW$_{AC}$ (high scenario).[5]

3.2.9 Environmental Benefit

PV systems reduce the need to generate electricity using fossil fuel. As a result, they reduce carbon dioxide (CO_2), nitrogen oxides (NOx), and sulfur dioxide (SO_2) emissions. This is referred to as the *environmental benefit*. These reductions include NOx, volatile organic compounds (VOC), particulate matter (PM), and CO_2. The value of these reductions depends heavily upon the quantification method. In particular, there is a wide variation in results

5. There were meetings with Forecasting and Economic Analysis, Treasury & Business Planning Dept. on March 8, 2002, April 17, 2002, and May 23, 2002, to discuss risk mitigation practices.

depending upon whether the quantification is performed using a cost-based analysis versus a market-based analysis (i.e., how much the market is willing to pay for the environmental benefits from PV systems).

An extensive analysis on the Environmental Benefits is included in the original paper including the use of Cost Based Analysis and Market-Based Analysis. There is a very wide range in valuation depending upon whether one uses a cost-based analysis versus a market-based analysis. The low end of the cost-based approach has a value of $38/kW; this is the value for the low scenario. A low-end estimate for the market-based approach is $300/kW (based on $0.010/kWh); this will be the medium scenario. A high end estimate for the market-based approach is $1,084/kW (based on $0.036/kWh); this is the value for the high scenario.

3.2.10 Governmental Incentives

SMUD's strong PV program has positioned it to capitalize on economic incentives offered by the state and federal government. This is referred to as the *governmental incentive benefit*. An extensive analysis of the Governmental Incentives is included in the original paper including the use of equipment incentives and R&D contracts that support SMUD's business interests.

The Governmental Incentives benefit per kW is based on the amount of PV SMUD has installed to date. The low scenario assumes that SMUD will receive no governmental incentives ($0/kW benefit). The medium scenario assumes that the district will receive an amount similar to previously granted Team-Up funds (perhaps from another source) and has $3 million research and development (R&D) value ($454/kW benefit). The high scenario assumes SMUD will receive an amount similar to the SMUD ReGen program funds supplied by the California Energy Commission (perhaps from another source) and has $13.6 million in R&D value ($1,514/kW benefit).

3.3 Value of PV for the Utility: New Business Opportunities

The district has developed a core competency in the distributed PV business while installing 10 MW of PV within its system. This core competency could be leveraged (or spun off into a new business entity) to provide the District with new business opportunities that will provide the District with additional revenue. An extensive analysis on the New Business Opportunities is included in the original paper discussing three opportunities for SMUD:

- Expand business model for existing district customers.
- Increase customer base to include non-district customers.
- Market program expertise to other municipal utilities.

3.3.1 Expand Business Model

The district's current business model is to produce/procure electricity and deliver it over its T&D system to its customers. Using this business model, SMUD earns revenue only when electricity is generated and delivered over the T&D system. Customers who produce their own electricity using distributed generation (or save it through energy efficiency investments) represent lost revenue to the district.

The PV Pioneers II program could help to expand the district's business model. It has the potential to protect the district against revenue and customer loss. Rather than earning revenue by producing and selling electricity, SMUD earns revenue by selling equipment and associated services. Revenue that is lost when customers generate their own power can be offset by an increase in revenue from the sale of equipment and services.

There are a variety of revenue sources that could be realized using this model. They include:

- Equipment sales. The district's bulk purchasing and relationships with suppliers will result in low-cost systems.
- Equipment installation. The utility has strong credibility in the eyes of current customers and would likely be given top consideration when choosing an installer.
- Financial services. SMUD could provide the financial services directly or it could work with a lender from whom the District gets a commission.
- Billing services. The utility could bill customers directly by adding a line item to a customer's monthly utility bill, thus making it more convenient to pay for systems.
- Equipment monitoring service. This service would notify customers if their system is under performing.[6] The district could provide a value added service to the customers who own the PV systems.
- Maintenance contracts. SMUD could sell fixed-price maintenance contracts that protect customers against future maintenance problems. This could be done in a manner similar to that paid by automobile owners who want to ensure they incur no maintenance costs over a certain period.
- Energy performance guarantees. The district could sell "insurance" that guarantees system performance.
- Financial performance guarantees. Since the district has some degree of control over utility rates, it could also sell financial performance guarantees that guarantee that the system will provide a minimum level of economic value.

Any or all of these services could be offered to SMUD customers in much the same way consumers have a range of options from which they can choose for their telephone service.

3.3.2 Sales to Non-District Customers

In addition to selling PV systems to customers, SMUD could expand its program to sell to customers outside its service territory. Many of the products and services identified above could be marketed to these new customers.

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6. For example, the Long Island Power Authority (LIPA) recently added the capability for its customers to evaluate the performance of its PV system on the LIPA website. See http://monitoring.lipapv.com/~lipapv/index.asp.

3.3.3 Market PV Program Expertise

SMUD has developed a good understanding of how to install PV in the most cost-effective manner as a result of its experience over the past decade. Its experience has helped the district in two major ways. First, the utility has determined how to reduce all aspects of the costs of PV systems, including: hardware, design, installation, transaction, and permitting. Second, SMUD's understanding of costs has enabled it to identify the most attractive markets for PV.

The district's PV program could be replicated at other utilities, especially the municipal utilities. There are several ways SMUD could capitalize on this expertise. One option is to charge utilities a program setup fee with the utility having the right to purchase the equipment for its program from whatever source it desires. Another option is for the district to charge a substantially reduced fee to set up the program with the requirement that the utility must purchase equipment for its customers from the district. SMUD, because of its marketing power, should be able to purchase equipment at less than what a small utility could and the revenue would come from its markup on the equipment.

New Business Opportunity Value

Assigning a value to the new business opportunities afforded by the district's program is not as analytically rigorous as assigning value for some of the other benefits. Even though this is true, it is important to provide an estimate of the value of these new business opportunities.

Alternate Business Model

The first business opportunity identified above is to obtain revenue from existing SMUD customers who purchase PV. To illustrate the potential profit to the district, the following assumptions are made:

- PV systems can be sold at a profit starting in 2008.
- District customers purchase 3 MW of PV systems in 2008 and increase purchases at a rate of 25 % per year (a total of 100 MW over 10 years).
- A profit of $200 per kW is made on the sale and installation and $20 per kW per year on the associated services (a present value of $500 per kW at a 6% discount rate and 2% inflation over the life of the PV system).
- The district captures all sales as a result of its strong PV program
- If it did not currently have a strong PV program, SMUD would have to build a program that initially gives it less market share; it would capture 10% in 2005, 20% in 2006, etc., until after 10 years, it would capture 100% of sales

These assumptions and the corresponding cash flows are presented in Table 3. Based on these assumptions, the district would have a discounted net profit of $32.3 million given its current PV program. It would have discounted net profit of $22.4 million if it did not have its program. Thus, SMUD has $9.9 million more than it would have had with no PV program.

Table 3: Example of profit from district sales of PV

	With PV Program			Without PV Program		
Year	Installed (MW)	Profit (Million $)	Discounted (Million $)	Installed (MW)	Profit (000's)	Discounted (Million $)
2003	0.0	$0.0	$0.0	0.0	$0.0	$0.0
2004	0.0	$0.0	$0.0	0.0	$0.0	$0.0
2005	0.0	$0.0	$0.0	0.0	$0.0	$0.0
2006	0.0	$0.0	$0.0	0.0	$0.0	$0.0
2007	0.0	$0.0	$0.0	0.0	$0.0	$0.0
2008	3.0	$1.5	$1.2	0.3	$0.2	$0.1
2009	3.8	$1.9	$1.5	0.8	$0.4	$0.3
2010	4.7	$2.3	$1.8	1.4	$0.7	$0.5
2011	5.9	$2.9	$2.1	2.3	$1.2	$0.9
2012	7.3	$3.7	$2.6	3.7	$1.8	$1.3
2013	9.2	$4.6	$3.1	5.5	$2.7	$1.9
2014	11.4	$5.7	$3.7	8.0	$4.0	$2.6
2015	14.3	$7.2	$4.5	11.4	$5.7	$3.6
2016	17.9	$8.9	$5.4	16.1	$8.0	$4.8
2017	22.4	$11.2	$6.5	22.4	$11.2	$6.5
Total	100		$32.3	72		$22.4

Source: Data collected by Thomas Hoff and Richard Perez

Market PV Program Expertise

Another market opportunity identified above is to market its program expertise to other municipal utilities. Suppose that the district helps other utilities to set up their PV programs at cost and then marks up its equipment sales (Option 2 described above). Assume that it earns a margin of $0.20/watt (W) and its program grows at a rate 2 MW per year in sales. As shown in Table 4, after 10 years, it will be selling at 20 MW per year and will have earned a discounted profit of $16.8 million.

Table 4: Example of equipment sales

	Sales (MW)	Profit (Millions $)	Discounted (Millions $)
2003	2	$0.4	$0.4
2004	4	$0.8	$0.7
2005	6	$1.2	$1.1
2006	8	$1.6	$1.4
2007	10	$2.0	$1.6
2008	12	$2.4	$1.9
2009	14	$2.8	$2.1
2010	16	$3.2	$2.3
2011	18	$3.6	$2.5
2012	20	$4.0	$2.7
Total	110		$16.8

Source: Data collected by Thomas Hoff and Richard Perez

For the low scenario, it is assumed that no advantage is obtained by having a strong PV program ($0 value). For the medium scenario, it is assumed that SMUD will have a moderate level of effort and will obtain half of the value of marketing its PV program for a value of $8.4

million ($840/kW). For the high scenario, it is assumed that the district will pursue an expanded business model in the district and will have a high effort to market its program outside the district for a value of $26.7 million ($2,670/kW).

3.3.4 Costs

This report has focused on the benefits that PV systems provide to the district. SMUD has installed district-owned and customer-owned PV systems. Assuming the operational characteristics of the systems are independent of ownership, benefits to the district do not depend on PV system ownership. To understand why this is true, consider each benefit in more detail.

The district has a reduction in demand and thus realizes an energy value whether it owns the PV system. The T&D system cannot distinguish between whether the resources are owned by the district or the customer, thus the district obtains the T&D deferral benefit. The amount of load exposed to market uncertainties (and thus the electricity price risk mitigation benefit) is the same whether the PV systems are district-owned or customer-owned. The same level of environmental emissions is obtained whether SMUD owns the system or the customer owns the system (the district should, however, retain the right to claim those benefits whether or not it owns the system). Governmental incentives are unchanged since the state buydown for customer investments is accounted for in the cost section. It is only the value of the new business opportunities that may increase slightly as a result of additional experience gained with customer-owned systems.

The fact that the benefits are the same does not mean that both ownership scenarios have the same financial effect on the district. SMUD incurs different capital, incentives, operation and maintenance (O&M), and "lost" revenue costs depending upon ownership. In addition, the method that the district chooses to account for these costs is critical.

As a result, since district-owned systems and customer-owned systems yield the same benefits to SMUD but have different costs, the economic evaluation is a problem of selecting the least-cost alternative.

The following assumptions are made in order to perform the cost analysis:

- PV system installed cost is $8,000/kW$_{AC}$ (whether or not the system is district-owned).
- Residential customers will pay the district $3,400/kW$_{AC}$.
- The present value O&M cost for district-owned systems is $250/kW$_{AC}$ (see Appendix C).
- The present value "lost" revenue for residential customer-owned systems ranges from $2,200/kW$_{AC}$ to $4,150/kW$_{AC}$.[7]

7. The District's Clean Power Estimator was run to perform this evaluation. The electricity bill reduction ranged between $128/kW$_{AC}$ to $242/kW$_{AC}$ per year depending upon rate structure and annual bill (due to the tiered rate structures). Assuming 2% escalation and a 6% discount rate, this translates to a present value of $2,200/kW$_{AC}$ and $4,150/kW$_{AC}$.

District Ownership

With the district-ownership approach, SMUD incurs a capital cost and an O&M cost. The installed capital cost equals $8,000/kW$_{AC}$ and the present value O&M cost equals $250/kW$_{AC}$. Thus, the total cost equals $8,250/kW$_{AC}$.

Customer Ownership

Customer-owned systems have two potential costs to SMUD: Initial incentive cost and "lost" revenue over the life of the PV system.

Initial Cost

The district buys PV systems for $8,000/kW$_{AC}$ and sells them to residential customers for $3,400/kW$_{AC}$. This initial cost, however, can be reduced using a buydown available from the state of California.[8] The buydown will pay $3,400/kW$_{AC}$ and, as discussed in the Government Incentives section, should supply about $3.4 million to the district. The result, as shown in Table 5, is that the initial cost to the district is $1,200/kW$_{AC}$ for 1 MW and $4,600/kW$_{AC}$ for more than 1 MW.

Table 5: Initial District cost with customer-ownership ($/kW$_{AC}$).

	With Energy Commission Buydown (up to 1 MW)	Without Buydown (above 1 MW)
PV System Cost	$8,000	$8,000
Customer Payment	($3,400)	($3,400)
California Buydown	($3,400)	N/A
District Cost	*$1,200*	*$4,600*

Source: Data collected by Thomas Hoff and Richard Perez

"Lost" Revenue

The second cost that the district faces is the "lost" revenue over the life of the PV system. The lost is in quotes because the philosophical perspectives that underlie the analysis define how one should evaluate "lost." One perspective is that anything that reduces electricity sales reduces revenue and thus should not be encouraged (note that this has negative implications for efficiency investments as well as distributed generation). Another perspective is that revenue loss should not be counted because customer investments in distributed generation are inevitable and thus, if SMUD did not sell the equipment, some other company would.

Rather than determining which perspective is best, the costs associated with customer-owned systems will be treated in three ways:

- There is no lost revenue.
- There is lost revenue assuming that residential customers with low bills will install the PV ($2,200/kW$_{AC}$).

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8. The terms of the buydown were obtained in a phone conversation with Vince Schwent on August 27, 2002.

- There is lost revenue assuming residential customers with high bills will install the PV ($4,150/kW$_{AC}$).

Total Cost

The total cost to the district equals the initial cost plus the lost revenue cost. Since there are two initial cost scenarios and three lost revenue scenarios, there are six cost scenarios for the customer-ownership. Table 6 presents these six scenarios. In addition, the table presents the cost of district-owned systems. All of these costs are the cost before the district applies its $3.3 million in public goods funding.

Table 6: Present value PV system costs ($/kW$_{AC}$)

	District-Owned	Customer-Owned		
Revenue Loss	N/A	High	Low	None
< 1 MW (with Energy Commission buydown)	$8,250	$5,350	$3,400	$1,200
> 1 MW	$8,250	$8,750	$6,800	$4,600

Source: Data collected by Thomas Hoff and Richard Perez

3.3.5 District Ownership

In the case of district ownership, the utility will incur the annual O&M costs and an inverter replacement cost in Year 15.[9] SMUD assumed an O&M cost of $0.0072/kWh and an inverter replacement cost of $116 per kW$_{AC}$ in its 2001 budget. Thus, the O&M cost for a PV system with an 18% capacity factor is $11.35 in the first year. The present value O&M cost, when the O&M cost is escalated at 2% per year and the discount rate is 6%, is $200 per kW$_{AC}$. The discounted inverter replacement cost is $47 per kW$_{AC}$. The present value O&M cost and inverter replacement equal $247 per kW$_{AC}$.

3.3.6 Customer Ownership

In the case of customer ownership, the customer will incur all O&M costs and equipment replacement costs. While the district will incur lost revenue, it has determined that PV systems should be treated as demand side management (DSM) investments. The district's policy is that lost revenue associated with DSM investments should be excluded from the economic analysis. As a result, there is no reduction in the generation credit when the systems are customer-owned.

Results show that the benefits of PV deployment to SMUD range from $1,300/kW$_{AC}$ (low scenario) to $6,800/kW$_{AC}$ (high scenario). The range is mostly attributable to:

- The methodology used to quantify environmental benefits.
- The fraction of SMUD/Commission ReGen program that is accounted for.
- The degree to which SMUD capitalizes on new business opportunities.

On the cost side a SMUD ownership amounts to $6,600/kW$_{AC}$, while the cost of a customer ownership to SMUD ranges from $1,250/kW$_{AC}$ to $7,100/kW$_{AC}$ depending upon the treatment of

9. This is the approach taken by SMUD in the 2001 budget.

lost revenues (ranging from no loss of revenues to full loss per PV kWh produced), and upon the availability of Energy Commission buydown.

4.0 Conclusion and Recommendations

4.1 Conclusions

4.1.1 PV and Load Control: Determination of Effective Capacity

The capacity evaluation study showed that PV can significantly reduce customer peak loads for all the studied cases, in particular for schools and office buildings. Also, customer-sited PV installations provide an excellent match to SMUD's system load profile. In all cases, PV's effective capacity can be increased and firmed up with a modest amount of load control. Finally, the optimum collector geometry and solar load control strategy, for any case depends upon whether the local or systemwide load is to be maximally met by the PV system.

It follows that PV's capacity-credit benefit to SMUD indirectly depends upon customer ownership, particularly commercial/industrial customers. Indeed, customer-owners would tend to optimize system geometry and apply any load control strategy to maximize their economics. For example, a school will tend to install a south-facing array and implement any control to meet its noon-centered peak, whereas a southwest-facing system and a late-peak load management strategy would serve SMUD's interests better. This implies that SMUD may best maximize PV capacity with respect to its grid or any of its T&D systems by developing protocols wherein customer-owners would be rewarded for selecting PV geometries and control strategies optimized for SMUD rather than for itself.

Related to this point is the observation that the PV system and its maximization capability via storage or control need not be collocated to address a systemwide or T&D capacity constraint. One building could host a PV installation and storage, while another, more suitable to solar load control implementation, could host the load-control system.

4.1.2 Value of PV for the Utility: Net Benefits of System Ownership

The objective of the study was to quantify the benefits that PV provides to the district. Figure 11 and Table 7 summarize the benefits calculated in the report. The results suggest that the total benefits to the district range from \$1,313/kW_{AC} (low scenario) to \$6,848/ kW_{AC} (high scenario). The variation is due to three factors:

- The method used to determine the environmental benefit;
- The fraction of the SMUD/Energy Commission ReGen program contract that is counted; and
- The degree to which the district capitalizes on new business opportunities.

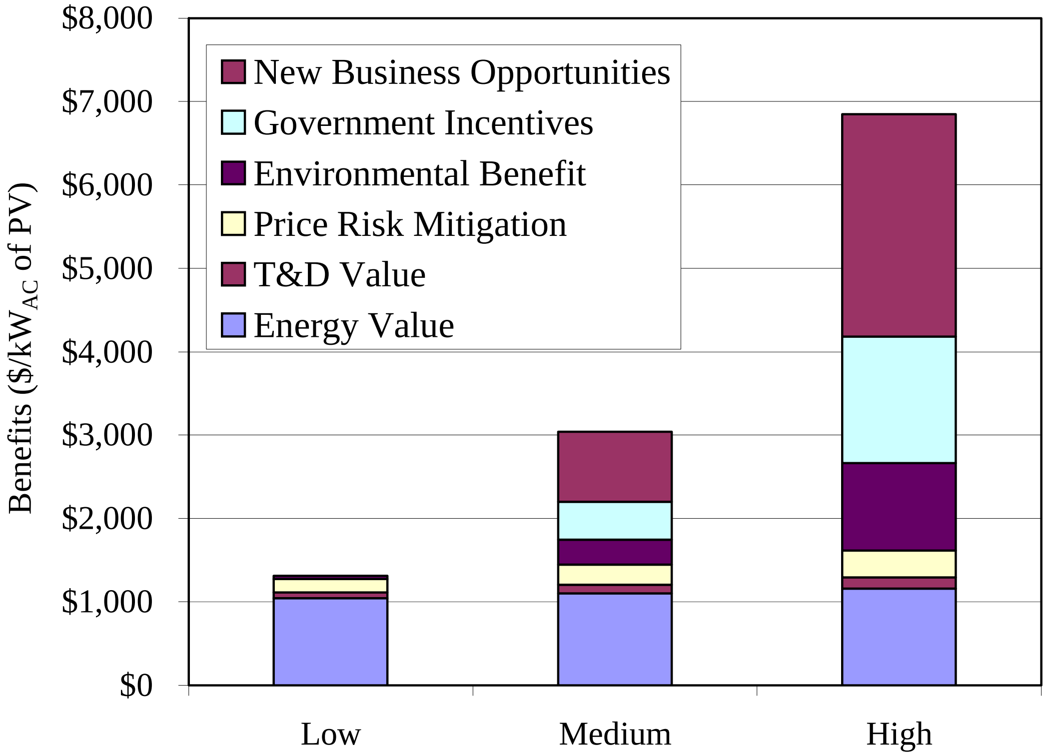

Figure 11: Total benefits

Photo Credit: Thomas Hoff and Richard Perez

Table 7: Total benefits ($/kW$_{AC}$)

	Low	Medium	High
Energy value	$1,043	$1,101	$1,158
T&D Value	$71	$104	$136
Price Risk Mitigation	$161	$242	$322
Environmental Benefit	$38	$300	$1,048
Government Incentives	$0	$454	$1,514
New Business Opportunities	$0	$840	$2,670
Total Benefits	***$1,313***	***$3,041***	***$6,848***

Source: Data collected by Thomas Hoff and Richard Perez

Net Benefit

The benefits to the district do not depend on who owns the system; rather, it is the costs that the utility incurs that are dependent on ownership. The effect can be assessed by evaluating the net benefit SMUD receives from the PV systems, where net benefit equals benefits minus costs.

To calculate the net benefit, suppose that SMUD will install 2 MW of PV over the next year. The low, medium, and high benefits to the district are $2.6 million, $6.1 million, and $13.7 million, respectively. The costs to the district depend upon system ownership, availability of Energy Commission buydown funds, and the treatment of lost revenue. The costs represent those above the $3.3 million the district has committed to public goods funding for PV.

- District-ownership cost: $13.2 million ($16 million capital cost plus $0.5 million O&M cost minus $3.3 million public goods).

- Customer-ownership cost: depends upon (a) availability of $3.4 million Energy Commission incentive and (b) treatment of lost revenue (Table 8).
    - Capital cost equals $2.5 million with Energy Commission funds ($16 million cost minus $6.8 million customer payment minus $3.3 million public goods minus $3.4 million California buydown) and $5.9 million without Energy Commission funds ($16 million minus $6.8 million minus $3.3 million).
    - Lost revenue equals $0, $4.4 million or $8.3 million.

Table 8: Total cost to the district for customer-owned systems

	$0 Lost Revenue	$4.4M Lost Rev.	$8.3M Lost Rev.
$2.5M Capital Cost	$2.5M	$6.9M	$10.8M
$5.9M Capital Cost	$5.9M	$10.3M	$14.2M

Source: Data collected by Thomas Hoff and Richard Perez

Figure 12 presents 12 different net benefit scenarios. The top, middle, and bottom tick marks on each vertical line correspond to high, medium, and low benefits. Customer-owned scenarios with no, low, and high lost revenue are on the left side of the graphs and district-owned scenarios are on the right. Figure 12-A includes the Energy Commission buydown while Figure 12-B excludes it. For example, Figure 12-A suggests that SMUD has a net benefit of $11.2 million for customer-owned systems that have no lost revenue and high benefits when the Energy Commission buydown is included.

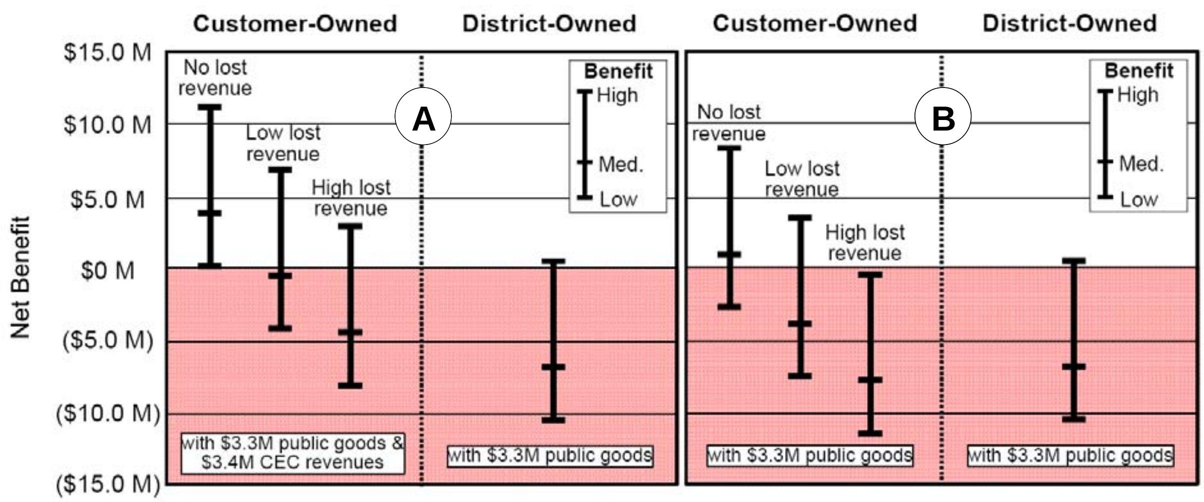

Figure 12: Net benefits to SMUD for ownership of 2 MW PV; A—buydown available, B—no buy-down.

Photo Credit: Thomas Hoff and Richard Perez

Several conclusions can be drawn from the figures:

- Customer-owned systems provide the district with higher net benefits than district-owned systems for almost every scenario.

- Customer-owned systems provide the district with a positive net benefit if it is assumed that there is no lost revenue for most benefit scenarios.

- Customer-owned systems may provide the district with a positive net benefit, depending upon: (a) whether customers who purchase the systems have low or high electric bills; (b) what level of benefits the district recognizes; and (c) availability of Energy Commission incentives

The net benefit analysis clearly indicates that in most likely case figures, a customer ownership would be more beneficial to SMUD than a utility ownership. The rationale for this conclusion is that the benefits of PV deployment to SMUD are independent of system ownership, but the cost to SMUD is less when customers own the PV power plants.

Therefore, if SMUD's objective is to maximize PV capacity with respect to its grid or any of its T&D systems, it should develop protocols whereby customer-owners would not be penalized by selecting PV geometries and control strategies optimized for SMUD rather than for them.

4.2 Recommendations

4.2.1 PV and Load Control: Determination of Effective Capacity

Recommendations, and follow-on steps from the capacity study include:

- Evaluate PV's EC for selected T&D systems, particularly where capacity limitation could be an issue.

- Evaluate PV capacity maximization strategies (via load control or storage) for selected prospective PV customer-owners but targeted to the T&D systems' loads and not the customer loads.

- Demonstrate and develop a pilot program designed to encourage the use of PV capacity maximization strategies for commercial-sector customers installing PV systems. This should include solar load control, minimum buffer energy storage and a combination of both.

4.2.3 Value of PV for the Utility: Determination of Net Benefits of Customer Ownership

The following recommendations for SMUD logically followed from the net benefit analysis:

- Continue installing customer-owned PV installations.

- Recognize that there are a number of scenarios under which SMUD is economically justified in spending funds beyond public goods on its PV program.

- Set a policy on how to treat lost revenues in future analyses.

- Maximize the benefits of the ReGen R&D program by integrating the present results with SMUD's business processes.

- Perform a comprehensive evaluation of its new business opportunities and quickly act on its results because opportunities are likely to diminish if action is not taken.
- Expand its business model to include the sale of services in addition to the sale of electricity.
- Market its know-how and programs to other municipal utilities.

Finally, a synthesis of both studies suggests that SMUD explore avenues and logistics for implementing customer-sited PV capacity maximization targeted to its own load requirements (systemwide or T&D) while letting the customer capture at least as much value as if they were targeting their own load. Customer-owners will tend to optimize system geometry and apply any load control strategy to maximize their economics. However, the optimum control/configurations for customers may be different than the optimum solution for SMUD—for example, the school will tend to install a south-facing array and will implement any control to meet its noon-centered peak, whereas a southwest-facing system and a late-peak load management strategy would serve SMUD's interests better.

4.3 Benefits to California

Many of the physical and economic constraints that define the PV-load relationship and the value of PV in the case of SMUD—solar resource, causes of peak demand, capacity constraints, and load growth—are also relevant to most major California utility companies.

Therefore, the benefits identified for SMUD through this investigation also apply generally to the State of California, including:

- PV has a significant EC to meet the demand of entire utility systems and many of their large customers: PV is a reliable peaking resource for California.
- A very small amount of solar load control (SLC) via minor customer load shedding or on-site storage usage (such as batteries or ice storage) can firm up PV's peak-shaving capability and remove all weather-based or peak-timing-based uncertainties. In effect, a modest amount of solar load control can make PV equivalent to a dispatchable peaking resource.
- Customer-sited PV could displace as much as 20% of SMUD's (and by extension California's) peak load without requiring any significant backup or storage infrastructure.
- There are several scenarios in which utilities could economically justify spending funds on their PV programs.
- Customer ownership of dispersed PV installations can improve utilities' bottom lines—as long as the utility takes advantage of business development opportunities associated with PV-system deployment and operation.

Utilities with weather conditions similar to Sacramento's cloudless summers can benefit from high effective capacities for PV systems. Adding load control or energy storage to a PVequipped building can increase its benefits to the electric utility. The relative merit of utility versus customer ownership of PV systems depends on how the utility accounts for the various values and costs of PV systems.

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Glossary

AC	Alternating Current. A type of electrical current that changes direction at regular intervals. In the United States, the standard frequency is 60 cycles per second.
Energy Commission	California Energy Commission
DLC	Direct load control which constitute a reliable and dispatchable capacity reserve for a utility.
ELCC	Effective Load Carrying Capability; a statistical measure of capacity, equivalent, from a user standpoint, to the probability of peak load reduction.
ERP	Emerging Renewables Program, of the California Energy Commission program whose goal is to develop a self-sustaining market for "emerging" renewable energy technologies in distributed generation applications. The program was created to stimulate market demand for renewable energy systems that meet certain eligibility requirements by offering rebates to reduce (buydown) the initial cost of the system to the customer.
Grid (Electrical grid)	An integrated utility system of electricity generation and distribution consisting of the wires, transformers, substations, power plants and control systems. The grid may also refer just to the transmission and distribution system, not including generation, particularly in regions where generation is owned by separate entities.
IOU	Investor Owned Utility, owned by shareholders.

kW	Kilowatt. A standard unit of electrical power equal to 1,000 watts, energy flow at a rate of 1000 joules per second.
kWh	Kilowatt-hour. 1,000 thousand Watts acting over a period of 1 hour. The kWh is a unit of energy. 1 kWh=3,600 kilo Joules.
kW_{ac}	Alternating Current Kilowatt-hour
MBES	Minimum Buffer Energy Storage; This parameter answers the question: How much stored energy – or how much load shedding – would be necessary to supplement PV output on the worse day, so as to insure that peak load reduction is equal to installed PV capacity, and further, how much more stored energy or shedding would be needed to accomplish the same task without the benefit of PV.
MW	Megawatt. 1,000 kilowatts, or 1 million Watts, a standard unit of electric power plant generating capacity.
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory, the primary federal laboratory for renewables, located in Golden, Colorado.
Peak Load	The highest electrical demand during a particular period of time. Daily electric peaks on weekdays usually occur in late afternoon and early evening. Annual peaks typically occur on hot summer days.
PIER	Public Interest Energy Research
Public Goods or Benefits Funds	Public Benefit Funds are state-level programs usually developed as part of a utility restructuring process to continue support for renewable energy resources, energy efficiency initiatives, and low-income support programs.

These funds are sometimes called a system benefits charge. Such a program is most commonly funded through a consumption charge to all electric customers, e.g., 0.2 ¢/kWh. Examples of how the funds are used for PV include: Rebates on renewable energy systems; funding for renewable energy R&D; and development of renewable energy education programs.

PV	Photovoltaic. The term used for the conversion of sunlight to electrical energy usually through the use of a PV cell, a semiconductor device.
PV Array	An interconnected system of PV modules that function as a single electricity-producing unit. The modules are assembled as a discrete structure, with common support or mounting. In smaller systems, an array can consist of a single module.
PV Module	The smallest environmentally protected assembly of solar cells.
PV System	A complete set of components for converting sunlight into electricity by the photovoltaic process, including the array and balance of system (BOS) components.
R&D	Research and Development
ReGen	Renewable Generation RD&D program at SMUD.
SMUD	Sacramento Municipal Utility District, the municipal electric utility in Sacramento, California that provides electric power to Sacramento County (and a small part of Placer County) at competitive rates that are consistently lower than investor-owned utilities in the state. SMUD is the sixth largest publicly owned utility in the country in terms of customers served. SMUD's mission is to provide value for their community while

	working to improve the quality of life in Sacramento.
T&D	Transmission and Distribution
TEAM-UP	Technology Experience to Accelerate Markets for Utility Photovoltaics, a program that used $15 million of United States Department of Energy funds to cost share over $75 million of PV installations in the United States. Over 1,100 PV systems were installed in 38 states over a five-year period.
TSU	Total storage utilization This parameter is similar to the MBES but represents the cumulative amount of load shedding necessary over a given period (e.g., a billing cycle) to guaranty a load reduction equal to PV-installed capacity.