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PHOTOVOLTAICS AS A DEMAND-SIDE MANAGEMENT OPTION: BENEFITS OF A UTILITY-CUSTOMER PARTNERSHIP

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INTRODUCTION

Pacific Gas and Electric Company (PG&E) has been involved in photovoltaic (PV) research for more than a decade. PG&E's efforts have ranged from basic cell research to the development of PV for utility-scale applications (PVUSA).[1] These projects have covered a range of research designed to enhance technical understanding and speed commercialization of PV for utility use. Throughout these efforts, PG&E has found PV to be a reliable, low maintenance, non-polluting energy producer that matches PG&E's loads.

Many in the PV community believe utility networks will eventually provide a large enough market to drive PV system costs down and thus establish PV as a significant power producing technology. Utilities have not found currently available PV technology cost-effective, however, except for niche applications utilizing small off-grid power supplies.[2]

The most promising utility-owned applications appear to be strategically sited PV systems within the transmission and distribution network. These applications maximize local and system benefits to the utility.[3] Current PV system costs, however, still exceed value, making PV uncompetitive. The same is true for customer-owned systems located on the demand side of the meter.[4]

This paper synthesizes previous efforts by proposing a utility-customer partnership. Such a partnership improves the economic feasibility of deploying grid-connected PV by maximizing the net benefit for parties on both sides of the meter. PV within this utility-customer partnership is called PV DSM, a utility-sponsored photovoltaic demand-side management program. This paper draws largely on a recent PG&E report[5] and presents the PV DSM concept, sample calculations for a test case, and compares PV DSM with more conventional utility-customer energy efficiency measures.

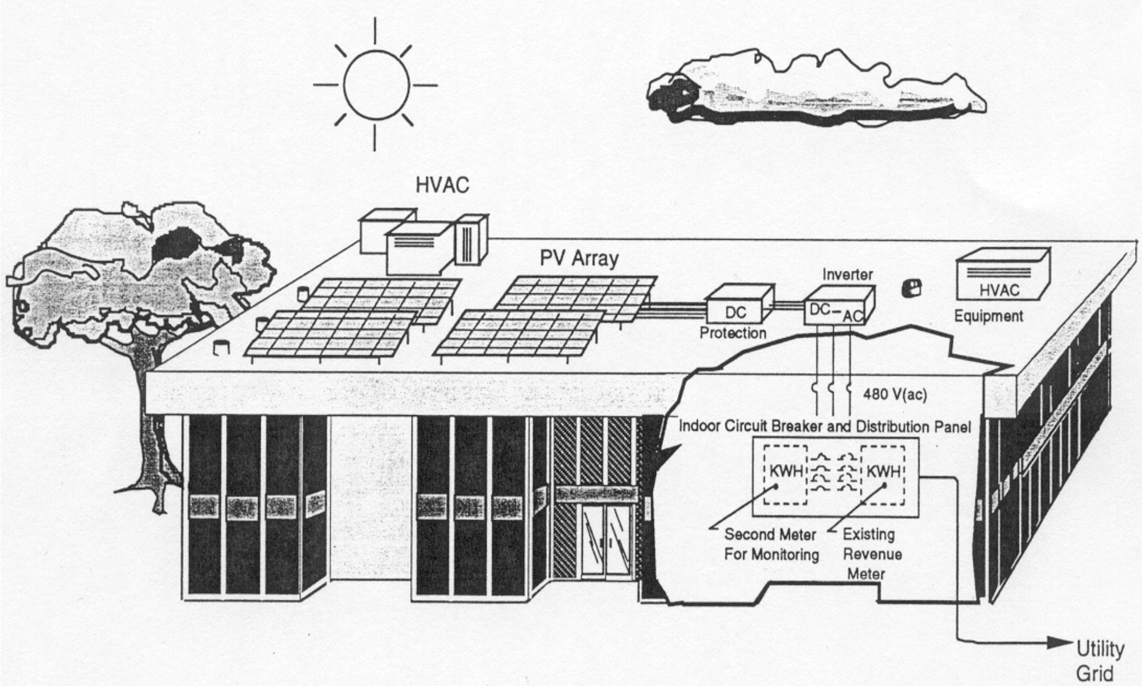

Figure 1. Customer-sited PV system illustration.

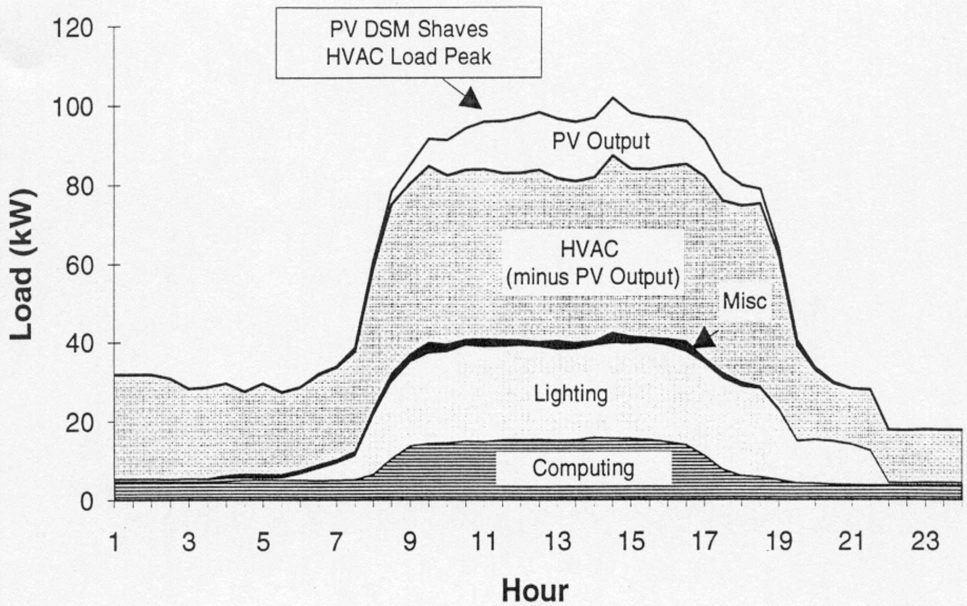

Figure 2. PV output matches PG&E R&D building daily load and shaves peak, June 21, 1990.

TECHNICAL OVERVIEW: WHAT IS PV DSM?

Figure 1 is an illustration of the major components of a customer-sited PV system. The PV array converts sunlight directly into DC. A power conditioning system electronically inverts the DC power into AC power which is directly fed into the building distribution panel for consumption.* A kilowatt-hour meter is used to monitor PV energy production.

There are many ways to structure a PV DSM program. For the purposes of this paper, it is assumed that the utility's role is to use financial incentives, such as rebates, to encourage customers in areas of high utility value to purchase and install PV systems. This arrangement is analogous to traditional utility-sponsored DSM programs.

The definition of PV DSM presented in this paper stipulates that the PV power system delivers electricity solely to the customer's load and does not back-feed power to the utility grid. This can be achieved either by sizing the PV system so that power output never exceeds customer load, or by installing a device to prevent back-feeding excess power to the grid. This stipulation renders the PV system "transparent" to the utility and makes it comparable to the installation of energy efficient appliances.

To illustrate, consider a high efficiency air conditioner replacement program. Both air conditioning loads and PV system output are highly correlated with sunlight availability. Thus, both high efficiency air conditioners and PV systems have similar impacts on a building's peak load and electricity consumption. As long as PV power is used to serve the building's loads only, the utility does not know whether the customer has a PV system or a high efficiency air conditioner.

Figure 2 demonstrates this concept on a daily basis using actual load data from PG&E's Research and Development building, a representative commercial office building with daytime occupancy. The building load is dominated by the air cooling (HVAC) system. The power output from a 15 kW PV system located on the roof of the building is subtracted from the HVAC load.**

The peak load occurs at 2:30 PM and is about 102 kW without the PV system. A PV DSM system reduces peak load to 88 kW, and effectively acts like a high efficiency HVAC system: it reduces the HVAC load by 23 percent at peak and provides consistent load shaving throughout the day.

Figure 3 demonstrates this concept further by using a year's worth of measured HVAC load data from PG&E's Research and Development building. There are three load duration curves*** plotted. The top curve is the load duration curve (LDC) for the original HVAC system; the HVAC load peaks at about 70 kW. The second curve is the LDC for a *hypothetical* HVAC system. This "efficient" HVAC system has 21.5 percent less demand during all operating conditions than the original HVAC system. The third LDC is for the original HVAC system coupled with a 30 degree tilted fixed flat-plate PV system. The PV system is rated at 15 kW (21.5 percent of the HVAC peak load).

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*PV system output could alternatively be directed to a specific piece of equipment, such as an air cooling unit.

** PV output is simulated using actual on-site weather data.[6]

*** Load data in a load duration curve are re-sorted from chronological order to descending load order. The highest load of the year is at the far left of the plot and the lowest load is at the far right of the plot.

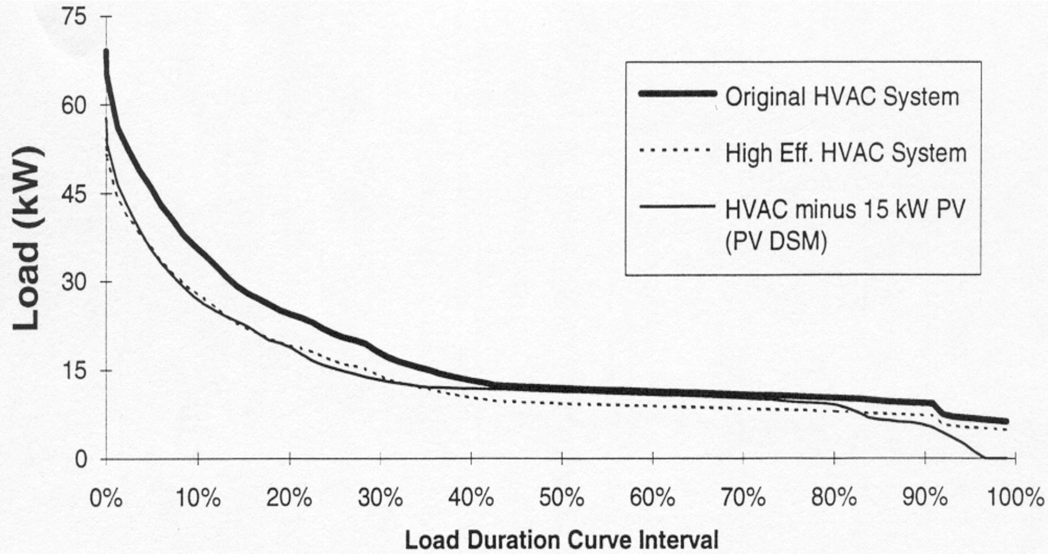

Figure 3. HVAC Load Duration Curves for PG&E's R&D Building (7/90 to 6/91).

These curves show that the two demand-side management options provide similar peak load reductions and annual energy savings. That is, from the utility's perspective, the original HVAC system coupled with the PV system (PV DSM) behaves like a high efficiency HVAC system. In particular, the top third of the load duration curves are essentially identical. (The top of the LDC curve is of critical importance to utility planners, since capital expenditure decisions are based on peak loads.) Thus, PV output correlates extremely well with specific building equipment loads. This finding is consistent with past studies, which indicate that PV output matches the load profile of many PG&E distribution feeders, and the PG&E system as a whole.[3,7]

An effective PV DSM program would initially use customer-sited PV systems to relieve peak loads in areas constrained by transmission and distribution capacity. Distribution circuits with a high saturation of commercial customers appear to be favorable targets for PV DSM, since commercial loads closely match PV output. Other reasons favoring commercial over residential applications for early market entry include tax advantages, easier control, fewer interconnects, and lower maintenance and administration costs. Therefore, the commercial customer is highlighted in this paper. (The potential residential market, however, is perceived to be substantial, and changes in economic assumptions, cost-effectiveness tests, and tax treatments could swing the attractiveness of PV DSM to residential customers in the future).[5]

COST-EFFECTIVENESS TESTS

Utilities use several cost-effectiveness tests when performing a DSM program evaluation. These tests include: ratepayer impact measure (RIM), total resource cost (TRC), participant cost, utility cost, and societal cost tests.[8] RIM directly measures the impact on rates and thus is of greatest interest to ratepayers and capacity planners. TRC is often used by DSM planners at PG&E as the bottom line evaluation tool because it considers a program's overall impacts. The participant cost test directly measures the economic impact on the particular customer participating in the DSM program; it is of greatest interest to that customer.

In the authors' view, the most appropriate tests for the evaluation of PV DSM are the RIM and participant cost tests, and a TRC test that includes participant tax impacts. The RIM test is necessary because it describes the impact of a program on ratepayers. The participant cost test is necessary because it describes the impact on a customer's financial resources and gives insight to the number of customers likely to participate.

DSM evaluations at PG&E have traditionally used a TRC test that treats participant tax impacts as transfer payments: taxes are excluded. Treating taxes as transfer payments is appropriate for traditional DSM because the impact of such action is usually small. However, such treatment of taxes for PV DSM may not be appropriate. Due to the high capital cost of PV systems, the utility will give rebates that cover only a small portion of the total system cost and the customer will likely finance most of the system. Thus, there are significant tax benefits available to the PV DSM participant that are not available to traditional DSM program participants. As shown in the following section, these tax related benefits account for about half of the total value to the participant. Excluding them from TRC calculations may give a distorted picture of the feasibility of PV DSM.

In order to satisfy the demands of traditional DSM evaluations while not unnecessarily penalizing PV DSM, TRC is presented in two ways. First, it is presented as traditionally calculated (referred to as "Traditional TRC"); that is, participant tax impacts are excluded. Second, it is presented as suggested above (referred to as "Suggested TRC"); that is, participant tax impacts are included.

PV OWNERSHIP SCENARIOS

Various efforts have been made to economically integrate PV into the utility network. Three financial approaches are presented here to illustrate how the PV DSM partnership concept evolved:

1. **Utility ownership** of the PV system, installed on the supply-side of the meter;

2. **Customer ownership** of the PV system installed on the demand-side of the meter without incentives from the utility; and

3. **A utility-customer partnership**, where the utility provides customer incentives to purchase and install the PV system on the demand-side of the meter.

Financial results are presented in 1992 dollars per kW of PV.*

Utility Ownership

First, consider the case of a strategically sited utility-owned PV system on the supply-side of the meter. The value of this type of "grid-support" system has previously been evaluated for a specific test case in PG&E's distribution network.[3] Figure 4 presents the results of this analysis by its two components: (1) "Bulk System Benefits", which account for the avoidance of energy and capacity costs from bulk generating stations; and (2) "Distributed Benefits", which account for the benefits to the local substation and distribution system, such as hardware life extension, electrical loss reduction, and voltage support. Cost exceeds value even when distributed benefits are included, rendering the installation uneconomic.

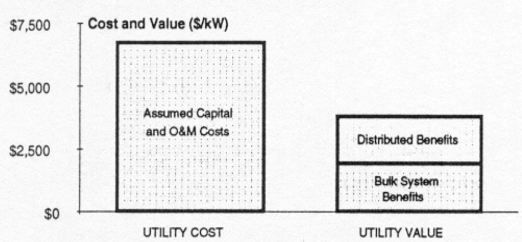

Figure 4. Utility Ownership: Cost exceeds value to the utility.

Customer Ownership Without Utility Incentives

Figure 5 shows the cost/value results for the case of a customer-owned system, installed without the direct involvement of the utility. Such installations have been labeled demand-side management (DSM) systems because of their ability to meet the peak electrical load of, for example, commercial buildings.[4,9] This approach places costs, responsibility, and benefits of PV directly with the customer. The value to the customer is gained through savings on the utility bill, federal and state solar tax credits, and other tax benefits. Although the economics improve over the utility ownership scenario, this approach is also not cost-effective since cost exceeds value.

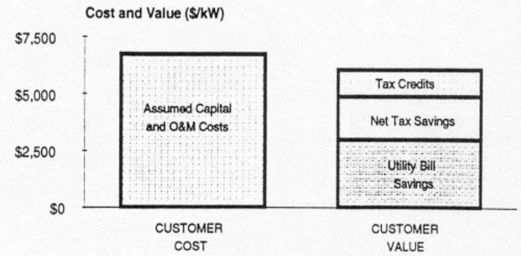

Figure 5. Customer ownership without utility incentives: cost exceeds value.

Utility-Customer Partnership

Figure 6 depicts a utility-customer partnership where the utility encourages customers to install PV systems through the use of rebates. The result is that both the utility and the participating customer benefit, since value exceeds cost from both perspectives.

Table 1 shows the details of these results from several perspectives: RIM test, participant cost test, and total resource cost tests. As described earlier, the TRC test is presented in two ways: Traditional TRC and Suggested TRC. The results are presented in terms of net present value (NPV), where NPV equals value minus cost. A DSM measure is viable when the NPV is greater than or equal to zero, and when the benefit-cost ratio is greater than or equal to one.

Table 1. Cost-Effectiveness Tests ($/kW).

	Test Perspective			
Cost Category	***RIM***	***Partici-pant Cost***	***Tradi-tional TRC***	***Suggested TRC***
Avoided Marginal Costs	$3,800		$3,800	$3,800
Rebates to Participants	-$ 750	$ 750		
Reduced Utility Bills	-$3,000	$3,000		
Net Tax Impact**		$1,896	$ 0	$1,896
Tax Credits		$1,161	$ 0	$1,161
Installed Cost		-$6,500	-$6,500	-$6,500
Maintenance Cost		-$ 240	-$ 240	-$ 240
NPV	**$ 50**	**$ 67**	**-$2,940**	**$ 117**
Benefit/Cost Ratio	**1.01**	**1.01**	**.56**	**1.02**

Table 1 shows that the utility-customer partnership is financially viable from all three perspectives: rates decrease for ratepayers (RIM test); the participating customer earns the desired rate of return (participant cost test); and the combined result decreases costs from the Suggested TRC perspective.

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* Table A-1, at the end of this paper, contains the customer and PV economic assumptions used in the evaluation.

** The Net Tax Impact on the participant has positive and negative components. Positive benefits include decreased taxes due to system depreciation ($1,733), loan interest deductions ($1,738), and O&M expense dedufuctions ($96). Costs include increased taxes from reduced utility bills which can be deducted as a business expense (-$1,204) , rebate tax (-$269), and tax credit taxes (-$198). Adding these figures together yields a net tax benefit of $1,896.

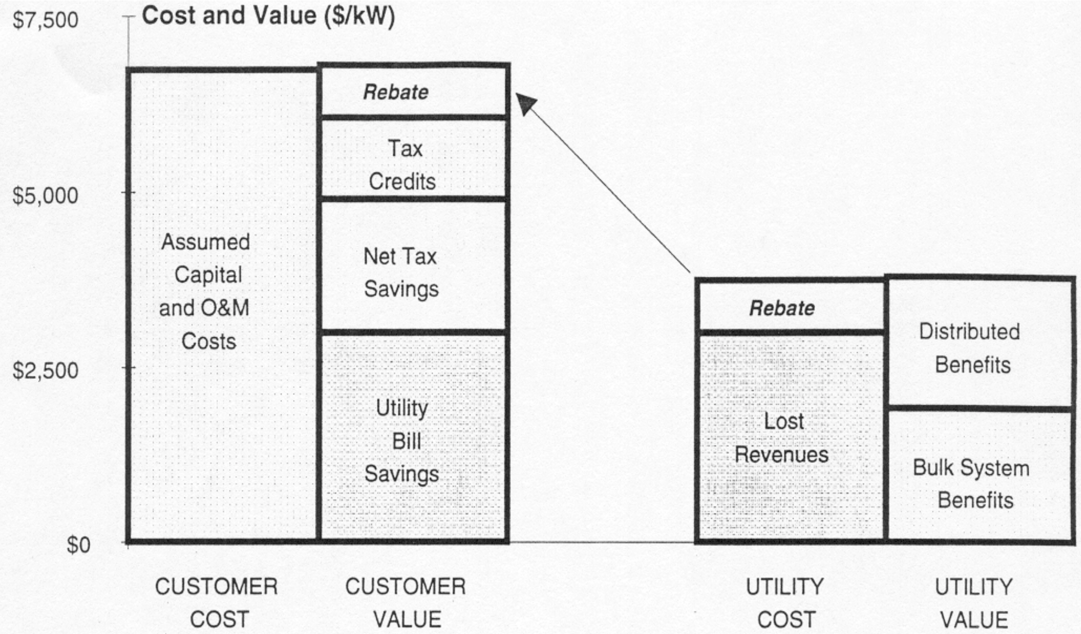

Figure 6. Utility-Customer Partnership: The economic potential of PV DSM.

SENSITIVITY OF RESULTS

The results are highly dependent on the economic assumptions. The intent of this paper is to present the concept and not to provide a comprehensive analysis. There are literally hundreds of thousands of different scenarios which would change the results in either direction.

Figure 7 puts the magnitude of variation of the results into perspective. This figure illustrates the sensitivity to assumption changes by providing three scenarios. The middle line in the figure is the test case used in this paper. The upper line ("favorable tax benefits") assumes that the Federal government offers a 20 percent rather than a 10 percent tax credit, and that the utility rebate is not taxed. The lower line ("no tax benefits") is a worst case scenario in which there are no tax credits and the customer is in a tax bracket that eliminates the value of all tax write-offs. Even with these few changes, the break-even capital cost (the cost at which the Suggested TRC benefit/cost ratio is 1) ranges from $3,600/kW to $9,600/kW. In other words, a few assumption changes have a large impact on the viability of a PV DSM partnership.

As shown in Figure 7, capital cost plays a major role in driving the economic viability of PV DSM. Unfortunately, due to the size of the grid-connected PV market, projecting the capital cost under a mature PV DSM program is difficult. In 1990, only 3 percent, or 500 kW, of the 15 MW of PV manufactured in the U.S. were used in grid-connected applications. The total number of U.S. grid connected PV systems installed to date is likely to be less than 300, the majority of which employ one-of-a-kind designs.

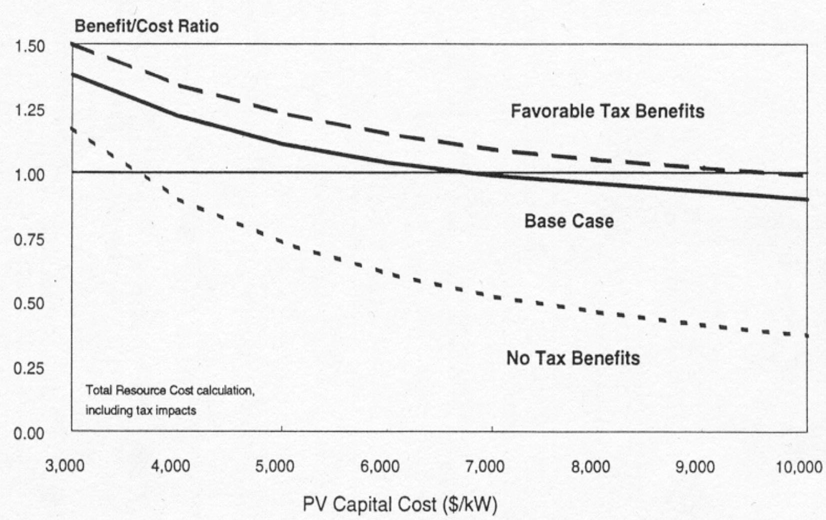

Figure 7. Impact of the customer's financial assumptions and costs on PV DSM viability.

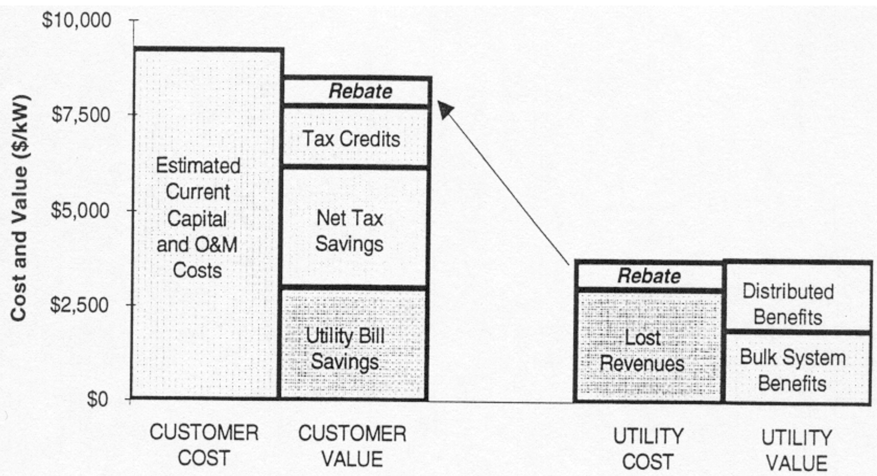

Figure 8. The economics of a PV DSM partnership at a capital cost of $9000/kW.

A one-of-a-kind customer-sited PV system presently costs around $9,000/kW. Figure 8 shows the cost/value relationship at this capital cost. Although the value to the customer increases with an increase in capital cost, PV is not cost-effective under these conditions.

This section demonstrates that PV DSM's viability is highly dependent on the customer's financial profile as well as PV system cost. Therefore, it is very difficult to draw definitive conclusions regarding market size and the target capital cost which will open the doors to economic viability. In-depth sensitivity and market analyses will be completed in future research phases at PG&E in an attempt to better characterize the potential of a PV DSM program. Other drivers of PV DSM cost-effectiveness include customer rate schedule, loan debt/equity ratio, loan life, interest, discount, and tax rates, and rebate level.

COMPARISON OF PV DSM TO OTHER DSM PROGRAMS

This section compares PV DSM to other conventional DSM measures using data from PG&E's only locally targeted DSM program.[10] The program, located in the Delta District, targets a high growth area near San Francisco.

DSM programs were evaluated in the Delta District using RIM and TRC tests. The TRC test used excluded tax impacts by treating them as transfer payments. Rather than presenting all of the programs, only those programs with the lowest and highest RIM and TRC benefit-cost ratios in each category (residential and commercial) are included.

Figure 9 shows that PV DSM is in the range of the Delta programs from a RIM perspective. A PV DSM program would have similar rate impacts as other conventional programs.

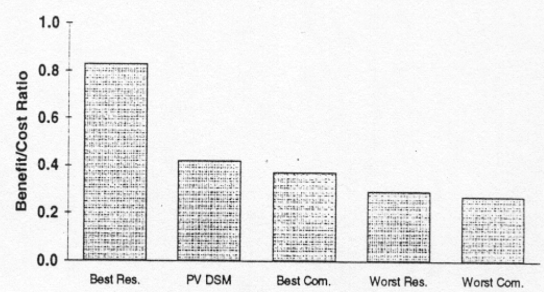

Figure 9. RIM benefit-cost ratios for DSM programs in the Delta District vs. PV DSM.

Figure 10 shows TRC benefit-cost ratios. The PV DSM TRC is presented in two ways: including tax impacts (Suggested TRC) and excluding tax impacts (Traditional TRC). Treating taxes as transfer payments (Traditional TRC) significantly reduces PV DSM's viability. PV DSM may be competitive with other DSM programs on a TRC basis, however, when tax impacts are included.

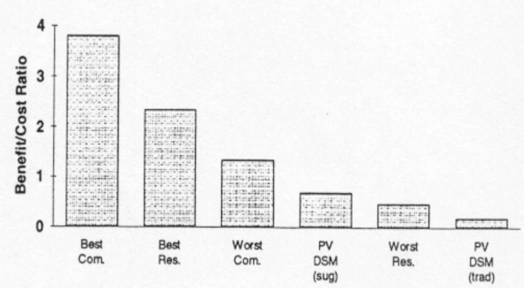

Figure 10. TRC benefit-cost ratios for DSM programs in the Delta District vs. PV DSM.*

* PV DSM is evaluted at a capital cost of $9,000/kW.

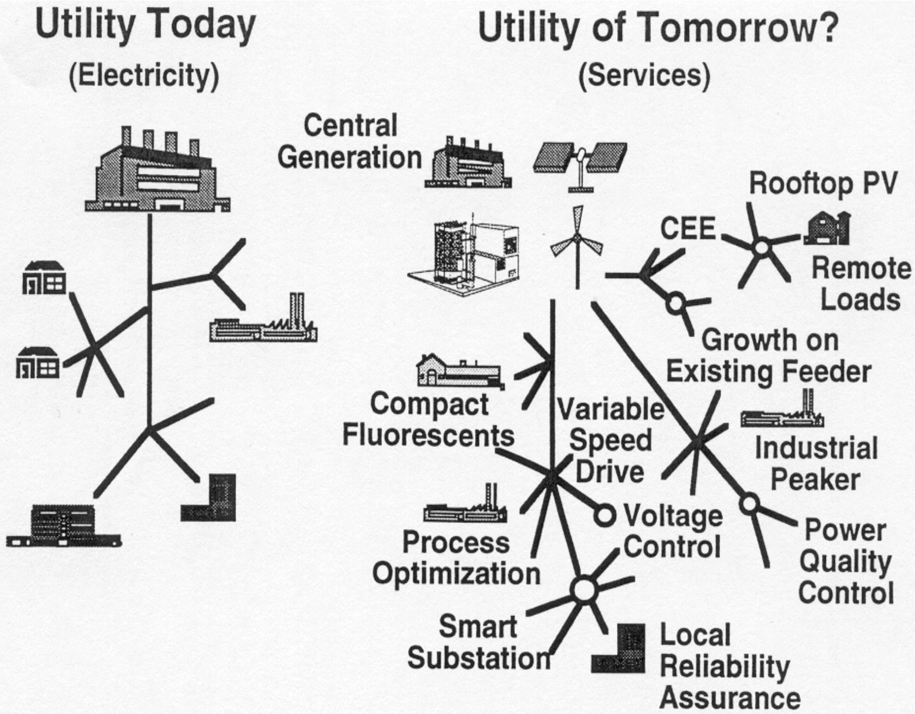

Figure 11. A central station utility vs. the Distributed Utility concept.

A VIEW OF THE FUTURE: THE DISTRIBUTED UTILITY[11,12]

Implementation of a PV DSM program requires a shift in utility thinking and planning. This shift is captured under a new utility paradigm called the "Distributed Utility", which is already emerging and under development at many utilities, including PG&E.[11,12] Figure 11 is an illustration of the Distributed Utility concept. The traditional central station utility of today is contrasted with a conceptual utility of tomorrow. The Distributed Utility integrates central station power plants with distributed generation and demand-side management applications that are strategically located within the utility network to lower the overall cost of serving customers.

PV DSM (and indeed other "small-scale" generation and storage technologies, locally targeted customer energy efficiency, and localized load-management programs) could prosper in the evolving vision of the utility system. Advanced integrated planning efforts have already been initiated at PG&E to determine the least-cost mix of technologies and demand management strategies for meeting local load growth and optimizing capital equipment investments.[13] These new planning concepts may lead to an improved model for the utility of the future that encourages or even features technologies with the characteristics of photovoltaics.

SUMMARY

PG&E is actively pursuing demand-side management programs.[14] Most of these DSM programs are designed to reduce customer loads through the use of devices that are of higher efficiency than those currently owned by customers (e.g., high efficiency HVAC, appliances, and lighting). The utility is able to encourage the use of such devices through rebates and other incentive programs. If the DSM programs reduce peak capacity and annual energy demands, the utility defers capital expenditures for new generation and for transmission, substation, and distribution system upgrades.

This suggests another option for the utility planner. PV DSM has the potential to offer the same, if not more, benefits to the utility as other DSM programs. With rebates or other utility incentives, the customer may be allowed to make a financially prudent decision by installing a PV system on the customer side of the meter. Both the utility and the customer have the potential to benefit economically when PV is deployed as a utility-sponsored DSM program. This partnership pushes grid-connected PV closer to cost-effectiveness.

Due to current capital costs and regulatory treatment of taxes, however, PV will probably not play a major role in PG&E's comprehensive plan to reduce system load in the next several years. Nevertheless, a near-term market goal of even a few megawatts of PV DSM per year would be a major breakthrough for the PV industry, and would serve as a catalyst for speeding cost reductions.

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APPENDIX

Table A-1. Commercial Customer Economic and PV System Assumptions.

	Customer
Incremental federal tax rate	34.0%
Incremental state tax rate	9.3%
Equipment depreciation[1]	5 years
Federal tax credit[2]	10.0%
State tax credit[3]	10.0%
Customer's invested equity[4]	20.0%
Loan interest rate	12.0%
Loan term (years)	25 years
Energy escalation rate	5.5%
General inflation rate	5.0%
Customer's discount rate	12.0%
Property Taxes[5]	none
First year energy rate[6]	$0.082/kWh
First year demand charge rate[7]	$79/kW
Rebate from utility	$750/kW

	PV System
Installed capital cost	$6,500/kW
First year maintenance cost	$0.01/kWh
Annual capacity factor	24%
System life	25 years

[1] Federal and state depreciation schedules use five-year, 200 percent declining balance.

[2] Federal tax credit expires 6/30/92 but is currently under review for extension.

[3] California state tax credit, available for non-residential customers, expires on 12/31/93.

[4] In its July 1990 Energy Technology Status Report, the California Energy Commission used a 70/30 debt/equity ratio for qualifying facilities (QFs).

[5] Solar equipment is exempt from property taxes in California through 12/31/93.

[6] PG&E's Schedule E-19S average rate, weighted by PV output, effective 8/1/91.

[7] Demand charge savings is a weighted value based on an 80 percent PV capacity factor during summer peak loads ($73) and 25 percent capacity factor during winter peak loads ($6).

The views, opinions, and evaluations presented herein do not necessarily reflect those of the Pacific Gas and Electric Company. The authors alone are responsible for the contents of this paper.

This paper is taken in part from a PG&E report "Photovoltaics as a Demand-Side Management Option, Phase I: Concept Development." If you would like to order the report, please contact Gretchen Bedard, Pacific Gas & Electric Company, Department of Research and Development, San Ramon, California, 94583 (telephone: 510-866-5577).