Evaluating the Revenue Impacts of Customer-Sited Renewable Generation Using Load Research Data

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Abstract: Pacific Gas and Electric Company (PG&E) recently applied Demand-Side Management (DSM) concepts to solar photovoltaic (PV) technology to develop the concept of photovoltaics as a Demand-Side Management option (PV DSM). This paper evaluates the ability of a hypothetical PV DSM installation on PG&E's Research and Development office building to reduce building energy and demand requirements. The analysis is based on a year's worth of measured load data and simulated PV output data (PV data are simulated using measured weather data). Results show that PV DSM has the potential to be an effective DSM tool.

BACKGROUND

Financial pressures and environmental concerns associated with traditional electric utility practices are encouraging utilities to satisfy customer demand using innovative approaches. One approach is to reduce demand using Demand-Side Management (DSM) programs. Several utilities have determined that this approach is cost-effective and have implemented aggressive DSM programs. Another approach is to satisfy increased demand using renewable energy sources. One promising renewable energy technology is photovoltaics (PV). Few utilities, however, have any grid-connected PV plants because this approach is not currently cost-effective.

Previous attempts at integrating PV into the utility grid have focused on either the utility's side of the meter (supply side) or the customer's side of the meter (demand side). A recent report[1] by Pacific Gas and Electric Company (PG&E) synthesized these two perspectives by suggesting a utility-customer partnership. Such a partnership may help to overcome the economic barrier to grid-connected PV plants by applying the DSM approach to PV technology. It is suggested that the utility's role within this partnership is to use financial incentives to encourage customers in areas of high utility value to install PV systems; the customer's role is to own the PV system. This partnership is called PV DSM.[*]

Figure 1 shows the potential results of a PV DSM partnership: using optimistic assumptions, PV can be cost-effective for both the utility and the customer. The right side of the figure shows that the value to the utility is greater than the cost: the utility benefits economically. The left side of the figure shows that the value to the customer is greater than the cost: the customer benefits economically. Figure 1 is optimistic from the customer's perspective in that it uses a capital cost that is lower than what currently exists. It is optimistic from the utility's perspective in that it assumes the system is sited in a high value location. The result in Figure 1 is very sensitive to assumptions such as the capital cost, tax impacts, and PV location within the utility network.

[*] By the authors' definition, a PV DSM system delivers electricity solely to the customer's load and does not back-feed power to the utility grid. This can be achieved by sizing the PV system such that power output never exceeds customer load or by installing a device that prevents power flow to the grid. This stipulation renders the PV system "transparent" to the utility and is comparable to the installation of energy efficient appliances.

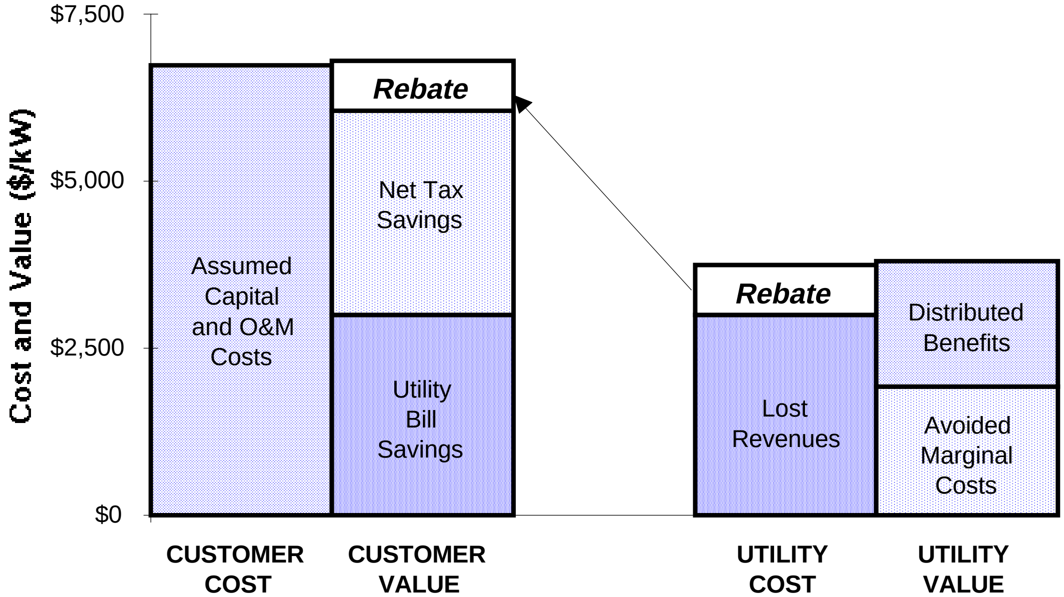

Figure 1. The economic potential of a PV DSM partnership.

OBJECTIVE

Numerous assumptions were made in the concept development report mentioned above.[1] One assumption was PV DSM's revenue impacts. Both utility and customer, however, need to accurately quantify these impacts. The utility needs to compare revenue reduction with anticipated cost savings to determine a program's cost-effectiveness; customers need to decide if PV DSM's total value (utility bill savings plus other savings) exceeds its cost.

A primary research objective is to more accurately determine PV DSM's revenue impacts in PG&E's service territory. Quantifying these impacts for a utility PG&E's size is a large task. This paper takes a first step in the evaluation by assessing the technical and economic impacts of a hypothetical PV DSM system[*] on a single building: PG&E's Research and Development (R&D) office building.

A secondary objective is to assess the impact of linking PV DSM directly with end-use loads. This will help to determine if PV DSM is comparable to traditional DSM measures on an end-use basis.

METHODOLOGY

Revenue impacts depend on PV DSM system performance, the temporal match between building load and PV output, and the customer's rate schedule. The impacts are quantified in a multi-stage process. First, PV output is simulated using hourly measured weather data. Second, PV output is correlated with hourly building load data. Third, the correlation between load and PV output is reduced to the energy and demand billing determinants.[*] Fourth, billing determinants are combined with rate schedules to compute revenue impacts.

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* The PV DSM system is hypothetical in that its output is predicted using models and measured weather data (accuracy of the models is about ± 5 percent).

* Energy billing determinant is the energy output by PG&E's time-of-use periods; demand billing determinants are maximum monthly demands at any time of the day for the entire year and maximum monthly peak period demands during the peak season.

DATA DESCRIPTION

Building Load

PG&E's R&D office building is located in San Ramon, California, a city 45 miles east of San Francisco. The R&D department occupies part of a building called the Sunset Building. The peak load for R&D's portion of the building is about 107 kW.

The primary issue addressed in this paper is PV DSM's ability to reduce total building energy and demand requirements. This total building load has been measured by PG&E. A secondary issue is PV DSM's ability to be linked to end-use building loads. PG&E is in the process of performing an extensive energy efficiency research project in R&D's part of the Sunset building.[**] In support of this project, building load data have been measured on a disaggregated basis. Building energy consumption is divided into several end-use loads, including two HVAC systems, two overhead lighting systems, three sets of plug loads, and a copy machine. These end-use load data are used in this paper to assess the ability to link PV DSM with end-use building loads.

Hourly building loads for the period July 1, 1990 through June 30, 1991 are used in the analysis.

PV DSM System

PG&E's R&D office building does not have a PV DSM system. Rather, PV DSM output data are simulated using measured weather data, insolation models, and PV output models. The weather data are measured on-site at San Ramon. Insolation models convert the horizontal insolation (total sunlight on a horizontal surface) and direct normal insolation (sunlight coming directly from the sun; i.e., sunlight not diffused by the atmosphere) to insolation on the fixed PV DSM system. PV output models combine the insolation incident on the PV DSM system with ambient temperature to calculate hourly energy output.

There are many ways to configure PV systems. They can be fixed, tracking in one dimension or two, and/or concentrating. Due to the need for simplicity, most roof-mounted PV DSM installations will probably be fixed, non-concentrating systems. Thus, the PV system in this paper is configured as a 30^{o} tilted, fixed flat-plate PV system facing due south. System rating is its AC output under conditions of 1,000 Watts/m^2 of sunlight (clear sky conditions) and 20^{o} C ambient temperature. A fixed PV system has about a 24 percent capacity factor at San Ramon based on the simulation model used. Hourly PV output data are for the period July 1, 1990 through June 30, 1991.

Rate Schedules

Medium, large, and very large commercial and industrial customers have utility bills composed of customer charges, energy charges, demand charges, credits, and penalties. PV DSM has the potential to reduce a customer's energy and demand charges. Medium sized customers have *maximum demand charges* while large and very large commercial customers have *maximum peak period demand charges* in addition to the *maximum demand charges*. The *maximum demand charge* applies to the maximum half-hour demand at any time during the month for each month during the entire year. The *maximum peak period demand charge* is based on the maximum half-hour demand during the month's peak hours (non-holiday weekdays, 12:00 to 18:00) for the summer season (May 1 through October 31).**Error! Bookmark not defined.**

Table 1 shows energy and demand charges for some medium and large commercial customers. Schedule A-10 is for commercial customers with peak demands less than 500 kW; E-19S is for

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** Data for the analysis in this report came from PG&E R&D's Advanced Customer Technology Test (ACT^2) Project.

firm service customers served at secondary voltage with peak demands between 499 kW and 1,000 kW. R&D is on schedule A-10. The two schedules differ in that E-19S has a summer peak period demand charge ($11.60/kW/month) while A-10 does not, E-19S has energy charges that vary by time-of-use and season while A-10 charges only vary by season, and E-19S has energy charges that are higher than A-10 during the summer peak period but lower during the rest of the year.

Table 1. Rate schedules.

	A-10		**E-19S**	
	Summer	Winter	Summer	Winter
Demand Charge ($/kW/month)	4.15	4.15	4.15	4.15
Peak Period Demand Charge ($/kW/month)	-	-	11.60	-
Energy Charge ($/kWh)				
Peak Period	.099	N/A	.113	N/A
Partial-Peak Period	.099	.077	.077	.065
Off-Peak Period	.099	.077	.058	.057

RESULTS

PV Output and Building Load Correlation

By definition, a PV DSM system delivers electricity solely to the customer's load and does not back-feed power to the utility grid. That is, the output is lost if PV output ever exceeds building load. Thus, it becomes important to determine the correlation between PV output and building load. Figure 2 shows that, on a typical summer day, a PV DSM system reduces total building load throughout the day with PV output never exceeding load.

The match between PV output and building load, however, is important not only on a typical summer day, but annually as well. Figure 3 uses a load duration curve technique to illustrate the annual match between PV output and building load. This figure shows the relationship between PV output and building load and also indicates how often PV output will exceed load.

Figure 3 was obtained as follows. First, simulated PV output data were chronologically correlated with building load data on an hourly basis. The data were then resorted from chronological order to descending load order. As the data were resorted, the correlation between PV output and load was retained. That is, as the load data were moved, the corresponding PV output data were moved with the load data. The PV data were then averaged. Figure 3 shows that there is an excellent match between building load and PV output; i.e., PV produces most of its energy when the building experiences its highest loads.

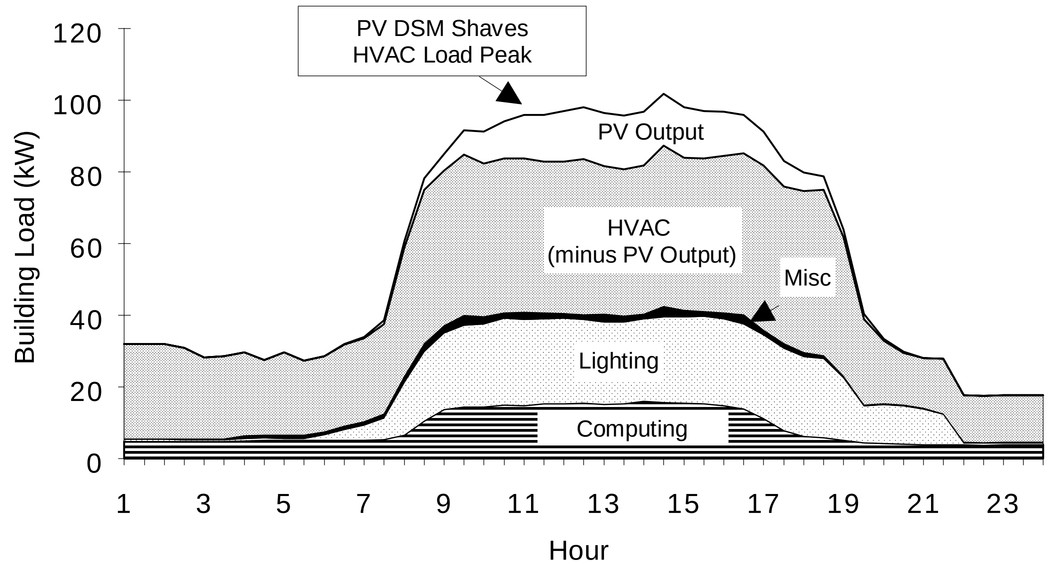

Figure 2. PV output and building load (by end-use) on June 21, 1990.

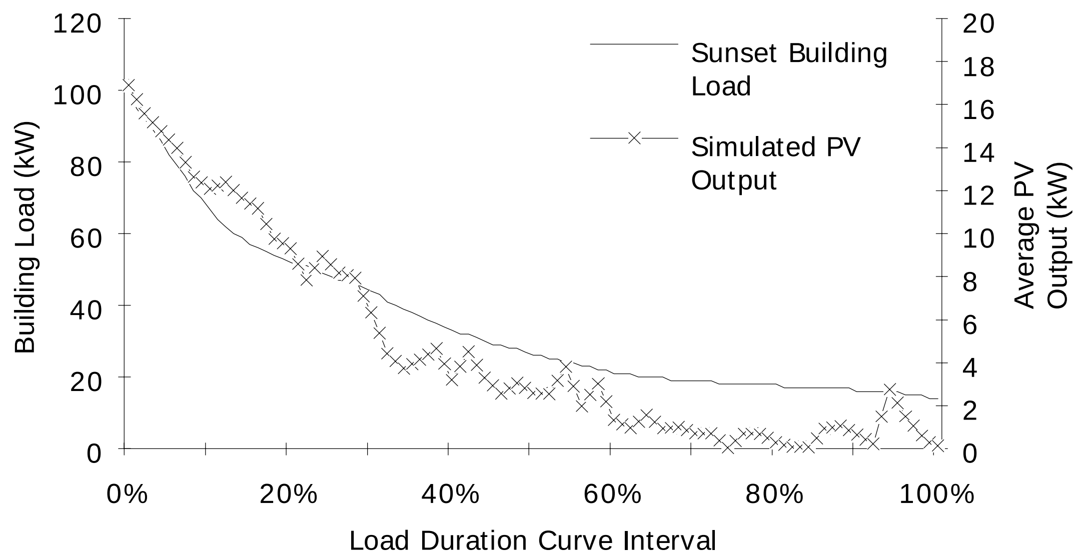

Figure 3. Annual match between PV output and building load.

Energy Billing Determinant

Revenue impacts attributable to energy savings are a function of energy output by PG&E's time-of-use periods, not PV output match to building load. Thus, although Figures 2 and 3 show that there is an excellent match between PV output and building load, they do not describe PV DSM's revenue impacts.

Energy charges for medium to very large commercial customers are based on time-of-use. Table 2 shows PV output's distribution by time period. The table includes the distribution of the year's hours by time period for comparison purposes. The most important comparison in Table 2 is in the first line: although the summer peak period accounts for only *9* percent of the year's hours, *25* percent of the PV plant's energy occurs during that period. Likewise, the partial-peak periods (both summer and winter) have a higher concentration of PV output than the number of hours for which the periods account. In fact, approximately two-thirds of the year are off-peak hours whereas two-thirds of the PV system's output is produced during peak or partial-peak hours.

Table 2. Distribution of PV system output.

Time Period	Percent of the Year's Hours	Percent of PV Plant Output
Summer		
Peak	9%	25%
Partial-Peak	10%	16%
Off-Peak	31%	19%
Winter		
Partial-Peak	20%	27%
Off-Peak	30%	13%

Demand Billing Determinants

As stated earlier, large commercial customers have two demand charges: monthly charges during peak hours for the peak season and monthly charges during any time of the day for all months of the year. Figure 4 shows the building's maximum demand by month during the summer peak period for PV DSM system sizes of 0 kW (original peak with no PV), 20 kW, and 50 kW. Figure 5 shows the building's maximum demand at any time of the day by month for the entire year.

Figures 4 and 5 show that PV DSM reduces the building's peak demand throughout the entire year, summer as well as winter, peak period as well as any time during the year. As PV DSM system size is increased, however, Figure 4 has a larger reduction than Figure 5. This is due to the fact that the *maximum peak period demand* (Figure 4) must occur during daylight hours (peak hours are between 12:00 and 18:00) while the *maximum demand* (Figure 5) can occur at any time of the day. The *maximum demand* shifts from high sunlight hours to low or no sunlight hours as the PV output satisfies a greater portion of the building load.

PV DSM System Size Impact

Another way to assess PV DSM's technical potential is to evaluate its marginal impacts. Figures 6 and 7 show the marginal impacts of PV DSM versus PV DSM system size. Figure 6 shows the marginal energy impacts and Figure 7 shows the marginal demand impacts. These figures show marginal, not total, impacts. Total impacts are determined by summing all previous marginal impacts.

Figure 6 quantifies how much of the additional energy from a marginal increment of PV is lost due to PV output exceeding building load. For example, the figure shows that there is almost no loss up to a system size of 20 kW (approximately one-fifth of the peak building load). The marginal loss starts out very small at PV DSM system sizes above 20 kW (a few percent per additional kW of PV) and increases with system size (up to two-thirds of the marginal output per additional kW of PV at the 100 kW size).

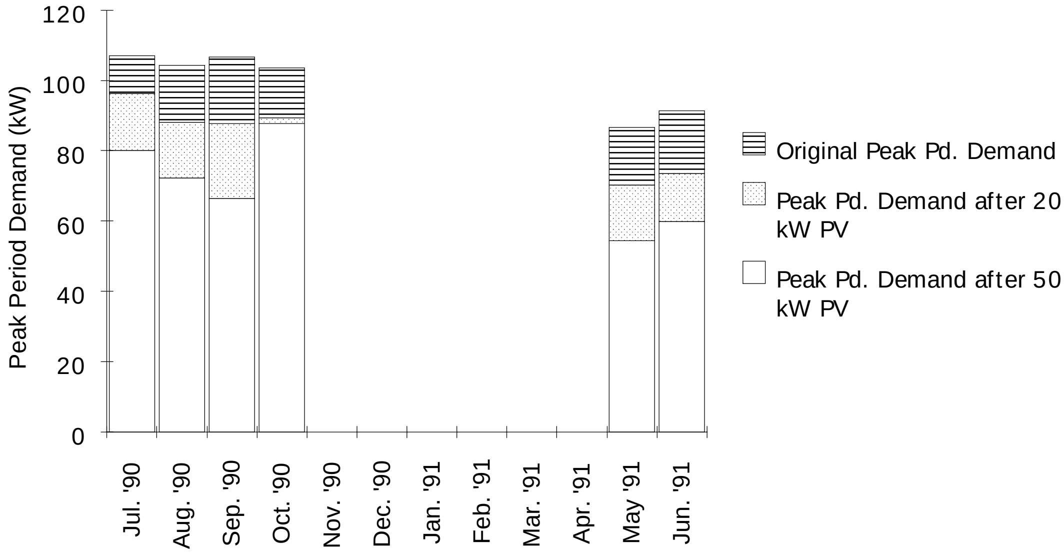

Figure 4. Peak period demand for varying PV system sizes.

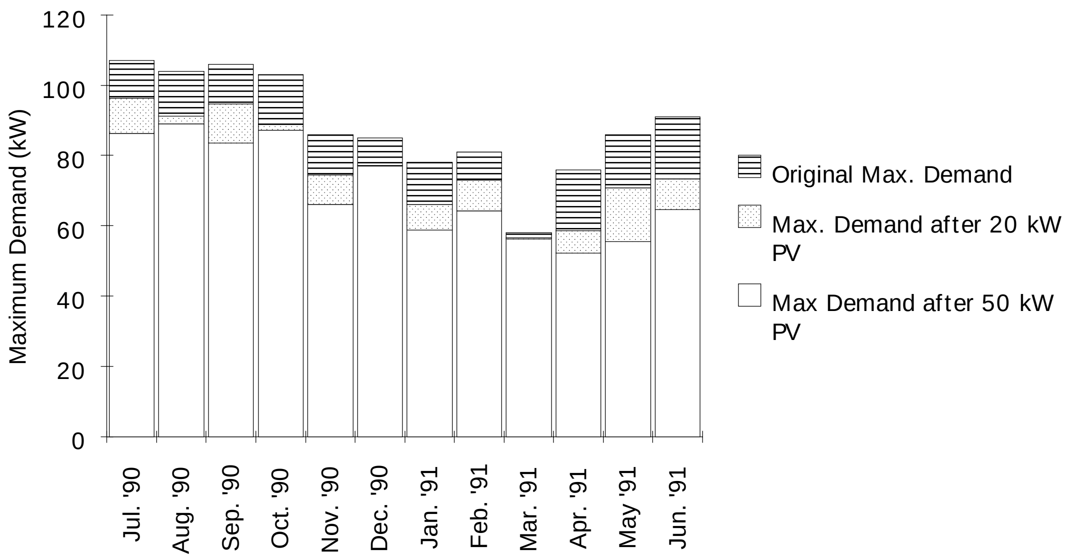

Figure 5. Maximum monthly demand for varying PV system sizes.

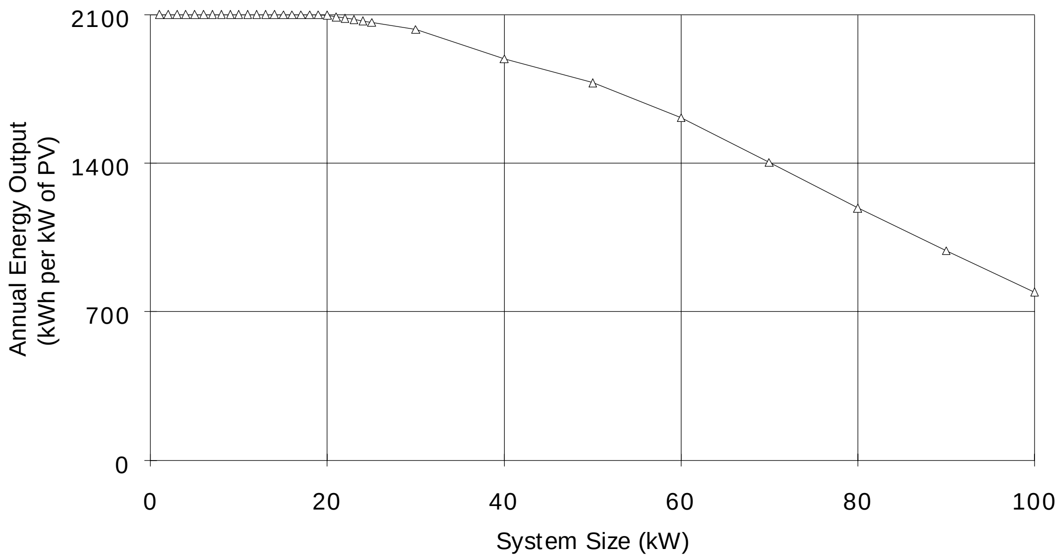

Figure 6. Marginal energy reduction versus PV DSM system size.

Figure 7 shows the PV DSM system's *peak period demand reduction* and *demand reduction* capability. *Peak period demand reduction* is the average monthly demand reduction during the summer month's peak hours. *Demand reduction* is the average monthly demand reduction at any time of the day during all months of the year. An additional kW of PV provides almost as much *peak period demand reduction* as the first kW (.83 kW per kW of PV) up to PV DSM system sizes of 18 kW. The *demand reduction*, however, begins to decline at system sizes above 5 kW. Although the *peak period demand reduction* is greater than the *demand reduction*, it is still surprising that a solar based technology provides such high annual *demand reduction*.

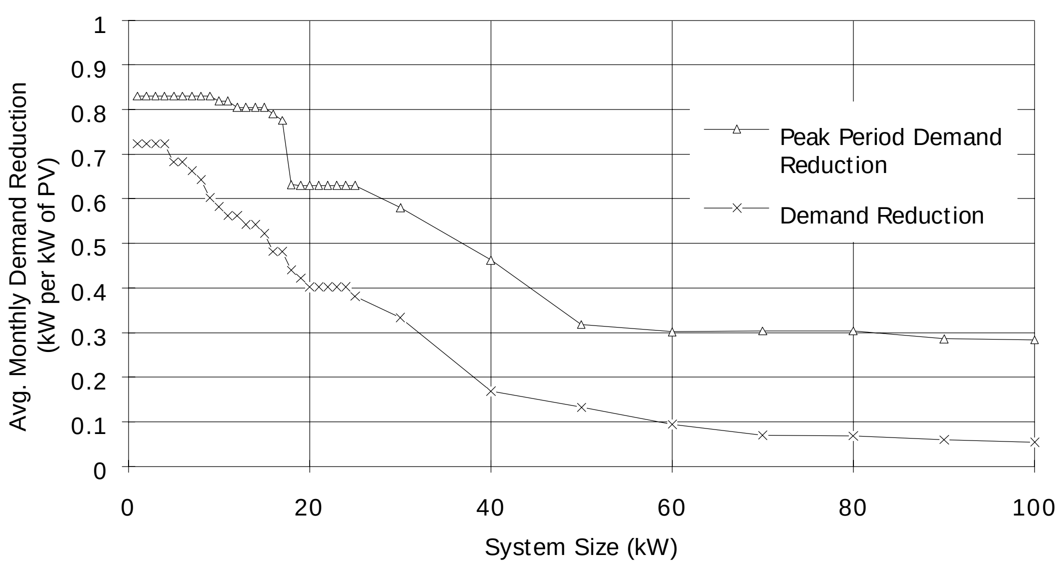

Figure 7. Marginal demand reductions versus PV DSM system size.

PV DSM's Match to End-Use Loads

One claim made by previous PG&E research was that PV DSM behaves like a DSM measure such as a high efficiency air conditioner.[1,3] Figures 8 and 9 show the total (not marginal) impact of a PV DSM system on end-use loads. "HVAC", the heating, ventilation, and air conditioning system, and "lighting" are only for a portion of those end-use loads; "data" is for all plug loads within the building (computers, task lighting, etc.). Total building load is included for comparison purposes. The lines are different lengths in the figures because it is assumed that the maximum PV DSM size is equal to the end-use peak load.

Figure 8 shows the end-use's reduction in energy usage and Figure 9 shows the reduction in the end-use's average monthly peak period demand. The peak demand for the HVAC load in Figure 9 occurred in the summer (and thus was cooling load) and was about 50 kW. Annual HVAC energy consumption was about 111 MWh. A PV system rated at 10 percent of the peak HVAC load (a 5 kW system) and linked to the HVAC system would be comparable to implementing an HVAC efficiency improvement that resulted in 10 percent energy savings (11 MWh, Figure 8) and 7 percent demand savings (3.4 kW, Figure 9). In other words, a PV DSM system linked to the HVAC load behaves similarly to an efficiency improvement in the HVAC's performance.

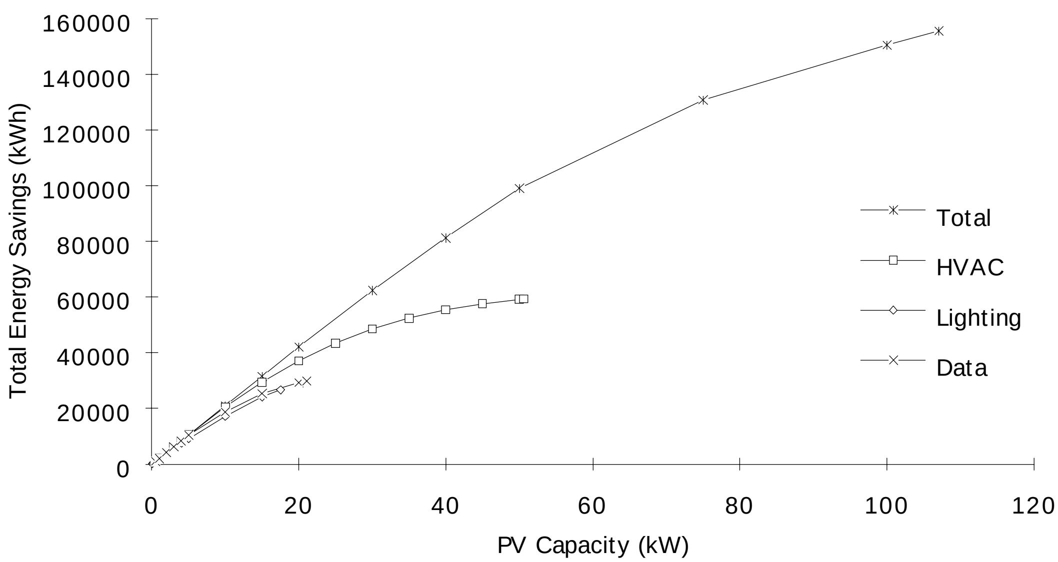

Figure 8. Total annual energy savings by end-use.

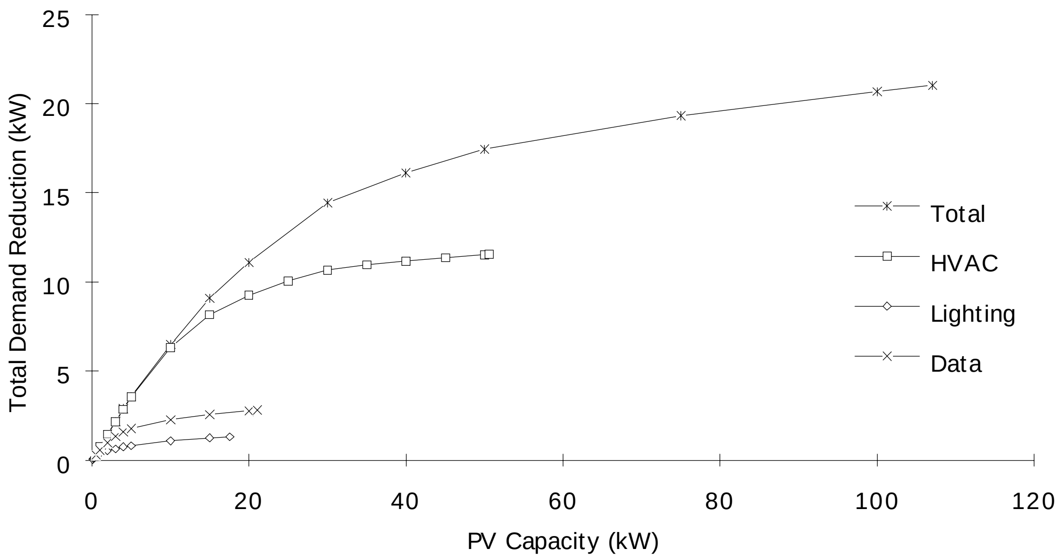

Figure 9. Total average monthly peak demand reduction by end-use.

PV DSM's Revenue Impacts

Figures 10 and 11 combine billing determinants with PG&E's rate schedules. As stated earlier, this paper is for a specific building (PG&E's R&D office building) on a specific rate schedule (A-10). In order to make the results of this paper more broadly applicable, however, it is of interest to evaluate PV DSM's revenue impacts using schedule E-19S in addition to schedule A-10. Figure 10 shows the first year revenue impacts as a function of PV DSM system size for schedule A-10 customers. Figure 11 shows the same information for E-19S customers.

The relationship between size and revenue impacts is linear in the first part of both figures. As the system size increases, however, energy is lost (PV output begins to exceed building load) and the impact of the PV system on demand savings is reduced. For both customer types, energy savings dominate total savings. Due to the peak period demand charge, E-19S demand charge savings are greater than A-10 demand charge savings.

This result can be translated to a net present value over the PV DSM application's life by assuming a system life, an inflation in utility rates, and a cost of capital. For example, a 20 kW PV system has a revenue impact of $4,500 in the first year for a customer on schedule A-10. Assuming a 25 year life, 5 percent rate inflation, and 10.5 percent cost of capital, the net present value of the revenue impacts is about $60,000.

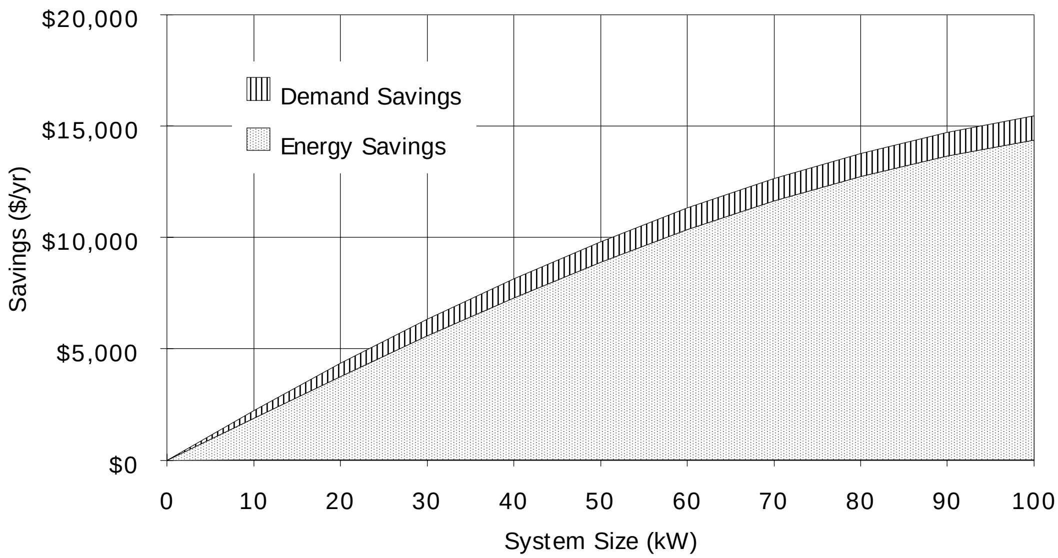

Figure 10. First year revenue impacts versus PV DSM system size (Schedule A-10).

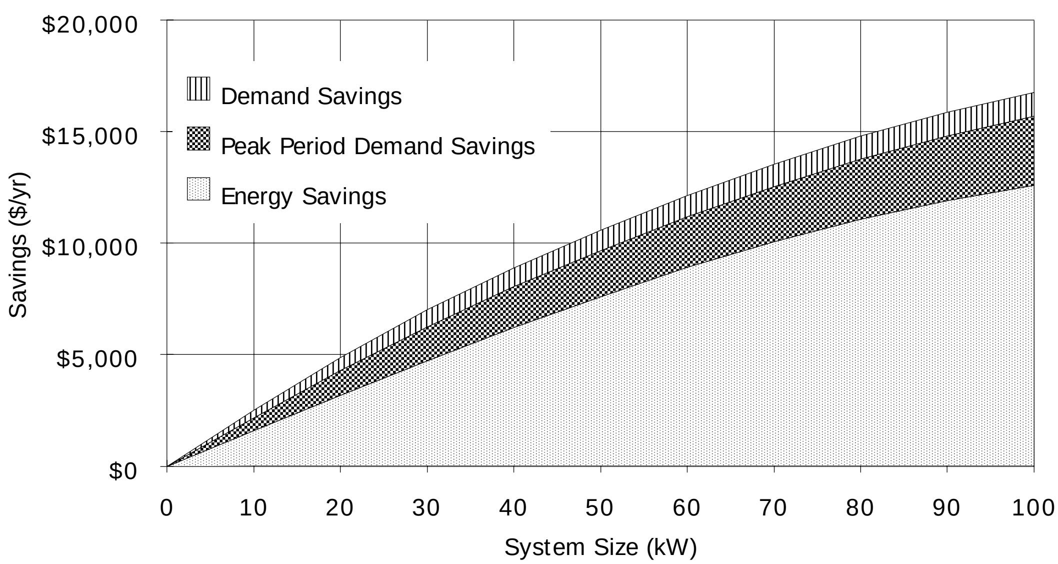

Figure 11. First year revenue impacts versus PV DSM system size (Schedule E-19S).

CONCLUSION

This paper has evaluated PV DSM's technical impact on PG&E's R&D building load and the economic impact on its utility bills. The energy and demand reduction capability of PV DSM by total and end-use building load was quantified and combined with rate schedules to determine revenue impacts.

Results show that PV DSM, like traditional DSM measures, would reduce the R&D building's energy and demand requirements. Although other factors need to be considered, a 20 kW fixed non-concentrating PV system may be a good choice for PG&E's R&D building (the building has a peak load of 107 kW). This system would reduce annual energy consumption by 13 percent (42 MWh), peak period demand by 15 percent (16 kW), maximum demand by 11 percent (12 kW), and would have negligible energy losses due to PV output exceeding the load. The R&D office building, which is on rate schedule A-10, would realize first year utility bill savings of about $4,500 and lifetime savings of about $60,000. Other rate schedules and/or longer PV DSM system lives could result in greater savings. (It turns out that these results are similar to the assumptions made in PG&E's initial PV DSM concept development report.[1])

From an end-use perspective, this paper showed that PV DSM linked to an HVAC system may be comparable with efficiency improvements in the HVAC system. For example, a 5 kW PV DSM system (10 percent of HVAC peak load) linked with the HVAC system would produce energy savings and demand reductions similar to energy efficiency reductions of 10 percent and peak demand reductions of 7 percent.

It can be concluded that, for this particular building, PV DSM behaves like other DSM measures in that it reduces both energy and demand requirements. In addition, significant (greater than 20 percent of peak load) penetrations of PV DSM are feasible with negligible PV output loss.[*]

It appears that PV DSM holds technical promise to reduce energy and demand requirements for some commercial buildings. The next step is to evaluate PV DSM's technical potential for other customer types in other locations and to extend this analysis to distribution system planning areas. Such information will assist PG&E in assessing PV DSM's potential for its service territory.

REFERENCES

1. Hoff, T., and H. Wenger, *Photovoltaics as a Demand-Side Management Option, Phase I: Concept Development*, Pacific Gas and Electric Company, Report 007.5-92.4, May 1992.

2. *Rate Finder*, Pacific Gas and Electric Company, May 1, 1992.

3. Wenger, H., T. Hoff, and R. Perez, *Photovoltaics as a Demand-Side Management Option: The Benefits of a Utility-Customer Partnership*, World Energy Engineering Congress, Atlanta, Georgia, October, 1992.

[*] If significant penetrations are realized, however, there needs to be protection to deal with the few hours of the year that PV output exceeds building load.