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Evaluating the economics of photovoltaics in a demand-side management role

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This paper examines current efforts to assess the economic viability of photovoltaics (PV) from a demand-side management (DSM) perspective. The benefits associated with dispatchable peak shaving PV DSM systems are discussed along with recent modelling efforts. Preliminary analysis, conducted at the Center for Energy and Environmental Policy (CEEP) together with Delmarva Power and Light, indicates that PV is closer to cost effectiveness, when assessed as a DSM option, than previously thought. PV DSM systems under investigation by CEEP include rooftop, non-dispatchable PV DSM and the integration of PV arrays and storage to provide dispatchable peak shaving capabilities. Analysis to date, on five case study utilities, shows that PV DSM systems can offer substantial value to utilities and their customers. Several policy options for promoting PV DSM are described along with a unique utility–customer partnership for the purpose of purchasing PV DSM systems.

Keywords: Photovoltaics; Demand-side management (DSM); Economic analysis

The availability of solar energy in several parts of the USA appears to correlate well with the types of days on which summer peaking utilities experience their highest demand (Perez *et al*, 1993). Summer peak loads tend to be driven by air conditioning requirements on long, hot sunny days, precisely the time when high solar insolation is also available. As a result, the effect of rooftop photovoltaic (PV) demand-side management (DSM)[1] systems on building load curves looks very much like a high efficiency heating, ventilation and air conditioning (HVAC) system upgrade (Wenger *et al*, 1992). DSM programmes that reduce a utility's peak demand, like high efficiency HVAC DSM programmes, tend to have higher value to utilities than other utility DSM programmes (Byrne *et al*, 1992). It is this high value PV opportunity that is modelled and evaluated below.

The economics of PV DSM

PV DSM systems can have both energy value (ie the system's ability to save energy) and capacity value (in the form of coincident peak demand reduction). The energy value credited to a PV DSM system is a function of the PV array's size and efficiency, and the availability of the solar resource. By producing energy on sunny days, rooftop systems can directly displace at least a portion of a building's needs from the utility.

Coincident peak demand savings from the deployment of PV DSM systems depend on the type of system used. A PV only system, in which storage is not included, would achieve demand reductions based on the output of the system at the time that the utility or the building is experiencing

[1]Because PV in a peak shaving role is similar to (and will have to compete with) conventional DSM technologies such as direct load control of electrical equipment or HVAC efficiency upgrades, we will use the term PV DSM to represent the application.

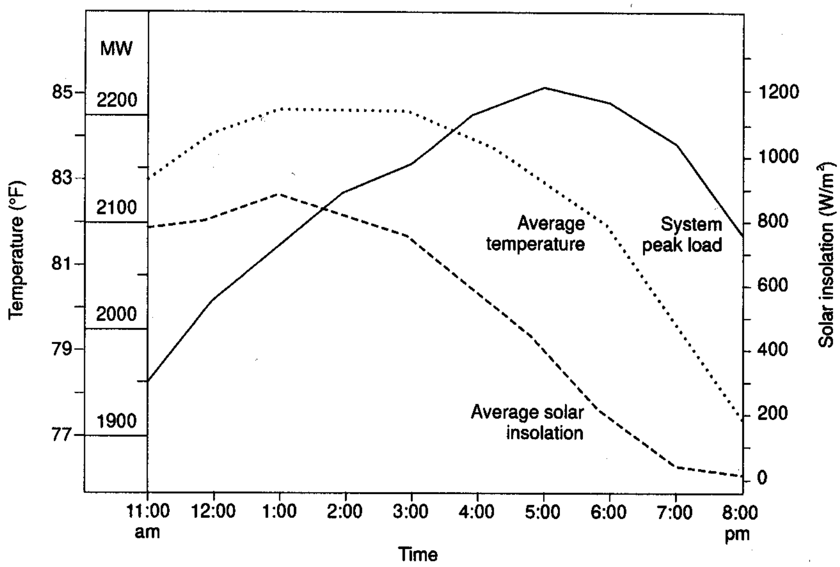

Figure 1 Utility system peak load, solar insolation and ambient temperature: 29 July 1992–31 August 1992[a]

[a]Range of solar insolation at 1:00 pm (DST) = 830 – 1100 W/m².

Source: Center for Energy and Environmental Policy and Institute of Energy Conversion, University of Delaware; Delmarva Power, Summer 1993 PV-DSM Test Results.

peak demand. Equation (1) describes how to calculate the demand reduction value of a PV only (or, as we will refer to it here, non-dispatchable) system.

$$kW_r = kW^* - kW_{pv}^* \quad (1)$$

where

kW_r = demand reduction of PV DSM system
kW^* = utility/building peak demand
kW_{pv}^* = PV output at time of utility/building peak

While probability estimates of kW_r can be made, neither the building owner nor the utility can be certain of the capacity value offered by a non-dispatchable system in any given year.

A second complicating factor is that while building or utility peak demand may often occur on days with abundant solar insolation, the time of day when peak demand is experienced may not be the same as when maximum solar insolation is available. Figure 1 shows the relationship between system peak loads and average solar insolation and ambient temperatures for the month during which Delmarva Power and Light Company experienced its 1992 summer peak (Delmarva is an east coast US utility serving electricity customers in the states of Delaware, Maryland and Virginia). This diagram illustrates that Delmarva Power and Light's system load typically peaks between 4.00 pm and 6.00 pm, several hours later than solar noon (or 1.00 pm, daylight savings time) when the peak output of the PV array occurs.

A PV DSM system equipped with modest amounts of storage could provide greater peak shaving benefits to utilities and building owners. Dispatchable PV DSM systems (ie ones that include storage) can maximize the power which can be made available during a utility's or building's peak demand period. Moreover, dispatchable PV DSM has the advantage of creating firm peak shaving capabilities. The concept of an integrated dispatchable PV DSM system design is illustrated in Figure 2.

For any given array size and module efficiency, the energy value of a dispatchable PV DSM system would be equal to the credit given to a non-dispatchable system, except for minor losses associated with a dispatchable system's round trip battery efficiency. However, peak demand reduction capability of the non-dispatchable and dispatchable systems would be quite different. The owner of a dispatchable system would have control over the number of hours and time of day the system would be deployed for peak shaving purposes, and could reliably expect a capacity value equivalent to at least the storage value of the system. Additionally, the system would be credited with the same peak reduction value given to the non-dispatchable system, based on array output at time of peak. Thus, dispatchable systems would always have higher capacity values and, as well, have reliability benefits unavailable to non-dispatchable systems. Equation (2) provides the calculation for estimating the demand reduction value of a dispatchable PV DSM system:

$$kW_r = kW^* - (kW_{pv}^* + kW_{bat}^*) \quad (2)$$

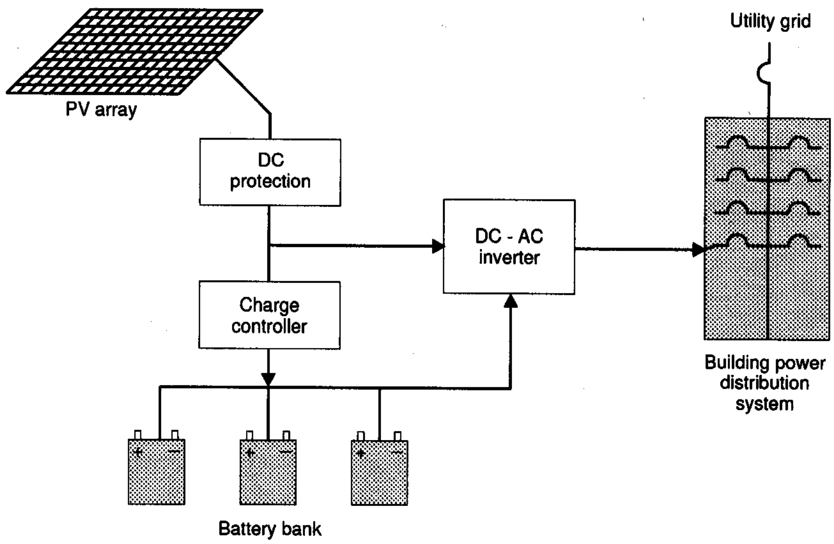

Figure 2 Conceptual drawing of a PV DSM system[a]

[a]Battery charging can be accomplished either by using array output, during the morning hours of low demand, or off-peak charging via the grid when rates are lowest. A dispatchable system capable of charging in both modes has been designed and tested by Delmarva Power and Light under a US Department of Energy contract.

Source: Center for Energy and Environmental Policy and Institute of Energy Conversion, University of Delaware; Delmarva Power.

where

kW_r = demand reduction of PV DSM system
kW^* = utility/building peak demand
kW_{pv}^* = PV output at time of utility/building peak demand
kW_{bat}^* = battery bank output (net of round trip losses) at time of utility/building peak demand

The kW_{bat}^* term represents the battery bank's output at the time the utility or building is experiencing its peak demand and is a function of the size of the battery bank and the number of dispatch hours.

An alternative to dispatchable PV DSM would be a battery only system. Such a system would utilize off-peak, base load generating units to charge a bank of batteries. The stored energy (minus round trip losses) would then be available for peak load dispatch. A present value revenue requirement (PVRR) analysis was performed to investigate the cost-effectiveness of battery only systems relative to dispatchable PV DSM systems. This analysis was performed based on three commercial building rate structures found in the USA that include demand charges in US$/kW and energy charges in US¢/kWh: below average (US$100/kW-yr and US¢3.0/kWh), average (US$158/kW-yr and US¢3.6/kWh), and above average (US$200/kW-yr and US¢6.0/kWh). For the average rates scenario, the PVRR's of the battery only system and the PV DSM system were approximately equal. For the above average rates scenario, however, the PV DSM system has a lower PVRR. The principal reasons why PV DSM performs well in comparison to battery only systems are: (1) battery systems must purchase energy, a portion of which is forfeited to round trip losses (in contrast, fuel costs for PV are zero); and (2) the PV array, as well as its battery unit, supply energy at the time of dispatch and, therefore, the size of the battery bank is considerably smaller for the PV DSM application than for the battery only option (Byrne *et al*, 1993). In addition, dispatchable PV DSM is an environmentally superior option to a battery only system because it has no adverse air quality or related health impacts.

Economic modelling of PV DSM systems

To conduct an economic analysis of PV DSM, we have developed a spreadsheet model that estimates benefits and costs associated with both non-dispatchable and dispatchable systems. This model utilizes a large amount of data to simulate the performance of a PV DSM system and to evaluate its cost effectiveness, based on accepted DSM accounting procedures employed by utilities in the USA. Case studies have been prepared for five diverse US utilities: Niagara Mohawk Power Corporation (NMPC), The City of Austin Electric (AUSTIN), Sacramento Municipal Utility District (SMUD), Delmarva Power and Light (DP&L), and an east coast urban utility (ECUU).[2] Table 1 provides a summary of key characteristics of each utility, while Figure 3 shows the geographical distribution of these utilities.

[2]This participating utility has requested that it remains anonymous.

Table 1 Selected utility characteristics

	NMPC[a]	DP&L	ECUU	SMUD	AUSTIN
Peak demand charge (US$/kW)	11	13	43	9	13
Peak energy charge (US¢/kWh)	5.7	4.0	6.8	5.9	2.8
Peak demand (MW)	6159	2736	7804	2145	1615

[a]Winter peaking; all others are summer peaking.

Source: Center for Energy and Environmental Policy, University of Delaware.

PV DSM system performance

Our spreadsheet model was used to estimate the performance of a PV DSM system with an expected 25-year life in the service territories of all five utilities. The system includes a PV array rated at 10 kW_p and a battery bank with storage capacities varying according to the average solar insolation in each utility's service territory (ranging from 48 kWhs to 88 kWhs). Hourly AC output of the PV array was simulated for one day in each of the 12 months resembling the typical day on which the utility experiences its monthly peak demand.[3] A typical meteorological year (TMY) data file was obtained for the major city located in the service territory of each utility. These data files are compiled by the US Department of Commerce's National Oceanic and Atmospheric Administration and represent a 'typical' year of weather for each location based on a 30-year data record.

[3]In the model, it is possible to evaluate the economics of PV DSM on either building or utility peak. But for the purposes of exposition, we focus here on the case of utility load peak shaving.

Figure 3 PV-DSM case study utilities

Table 2 Credited capacity for a 10 kW PV DSM system (kW)

	NMPC[a]	DP&L	ECUU	SMUD	AUSTIN
Non-dispatchable	0.7	4.3	4.4	3.2	4.9
Dispatchable	4.5	14.9	12.2	17.2	15.3

[a]Winter peaking; all others are summer peaking.

Source: Center for Energy and Environmental Policy, University of Delaware.

Global horizontal irradiance (a measure of solar energy) was obtained from the TMY file and adjusted to plain of array (POA) insolation values using site latitude and array angle. To maximize the system performance during the summer months, the array angle was set at latitude minus 15°. POA insolation, DC conversion efficiency and ambient temperature (obtained from the TMY file) were used in an algorithm found within the model to simulate hourly PV AC output. Although the model uses a simplified algorithm for simulating PV production, the estimates are very close to other PV simulation models that perform more complex calculations using additional parameters including ground albedo and wind speed.[4]

Once the energy values of the PV DSM system are estimated, the model aggregates the monthly energy production to an annual value, and performs a monthly load matching analysis. For dispatchable PV DSM systems, the model proceeds to estimate the battery storage needs. Hourly PV AC output is used to estimate monthly peak demand reductions. The model performs these calculations for either a non-dispatchable or dispatchable PV DSM system. To perform this analysis, an hourly utility system or building load profile is required for the peak day of each month.

For non-dispatchable systems, the peak demand reduction equals the PV DSM system's output at the time of day when the utility is experiencing peak demand, as illustrated in Equation (1). Demand reduction for a dispatchable system equals the PV array's output plus the energy released from storage during the dispatch period (Equation (2)). A four-hour dispatch requirement was assumed and dispatch hours were set based on the time of day the utility's system peak occurs. For both types of system, load matching analyses are conducted for each month of the year. Table 2 lists the credited capacities for the five case study utilities under investigation. These values equal the peak demand reductions, averaged over the utility's three peak months, from the operation of the PV DSM system.

Economic analysis of five case study utilities

The PV DSM system performance data are utilized in the spreadsheet, along with a variety of financial parameters (see Tables 3–6), to complete a present value analysis of system costs and benefits. Benefit-cost ratios are calculated from both a utility and customer perspective. An installed array cost of US$7500 per kilowatt is assumed (including PV modules and all balance of system components). An installed battery storage costs of US$200 per kilowatt hour is

[4]For example, comparisons of the spreadsheet estimates with those of PV-FORM, a commonly used software for this purpose, showed maximum differences of less than 3% for the case study utilities.

Table 3 Financial inputs: customer

	Unit	Value
Customer average income tax rate	(%)	38.50
Customer debt ratio	(%)	100
Customer discount rate	(%)	12
Customer loan period	(Years)	10
Customer evaluation period	(Years)	25
Customer loan rate	(%)	12
Customer depreciation life	(Years)	5

Table 4 Financial inputs: utility (IOUs)

		NMPC	DP&L	ECUU
Utility average income tax rate	(%)	35	38.50	38.50
Utility debt ratio	(%)	50	50	48
Utility pre-tax return on equity	(%)	16.9	11.75	9.79
Utility interest on debt	(%)	8.13	8.75	7.40

Table 5 Financial inputs: utility (municipals)

		SMUD	AUSTIN
Utility average income tax rate	(%)	0	0
Utility debt ratio	(%)	50	50
Utility pre-tax return on equity	(%)	11.75	7.00
Utility interest on debt	(%)	8.75	7.0

Table 6 Technical inputs: PV system

	Unit	Value
Equipment book life	(Years)	25
Installed battery cost	(US$/kWh)	200
PV equipment tax life	(Years)	10
Installed capital cost	(US$/kWh)	7500
Inspection and adjustment cost	(US$)	250
Inspection frequency	(Years)	1
PCS overhaul costs	(US$)	500
PCS overhaul frequency	(Years)	5
Battery replacement cost	(US$/kWh)	150
Battery replacement frequency	(Years)	7
Maintenance contingency cost	(US$)	250
Maintenance frequency	(Years)	1
O&M cost escalation rate	(%)	4.50
PV array size	(m^2)	105
DC conversion efficiency PTC	(%)	10.24
AC conversion efficiency PTC	(%)	9.53
Battery round trip efficiency	(%)	75

Table 7 PV DSM investment options: benefit/cost ratio comparisons

	NMPC[a]	DP&L	ECUU	SMUD	AUSTIN
Non-dispatchable					
Utility owned	0.40	0.48	0.51	na	na
Customer owned	0.61	0.63	0.74	0.62	0.63
Dispatchable					
Utility owned	0.41	0.66	0.52	na	na
Customer owned	0.69	0.76	0.98	0.73	0.75

[a]Winter peaking; all others are summer peaking; na: these are muncipal utilities, therefore, the methods for estimating benefits and costs are different from those of investor owned utilities. Currently, methods are being refined to allow for meaningful comparisons.

Source: Center for Energy and Environmental Policy, University of Delaware.

also assumed. Operating and maintenance (O&M) costs are set at US$500 annually for adjustments, maintenance, or any other unforeseen costs that may arise. In addition, US$500 every five years is factored into O&M expenses for overhauling the power conditioning unit. Batteries are replaced at a cost of US$150 per kilowatt hour every seven years. All O&M expenses are escalated by an inflation rate of 4.5% and discounted to their present value using each utility's discount rate (typically, this rate is based on the utility's average weighted costs of capital – see Kahn, 1988) or a commercial customer's discount rate depending on the ownership of the system.

For a utility customer investing in a PV DSM system, a primary benefit is the potential bill savings resulting from the operation of the system. It is assumed for the analysis reported here that a large commercial customer would undertake the investment in PV DSM. Furthermore, it is assumed that the customer experiences peak loads coincident with the utility's system load (ie PV output is compared to system load data to estimate peak shaving potential). Each participating utility provided their retail rate for large commercial customers. These rates include both a demand charge (US$/kW) and an energy charge (US¢/kWh) which may vary based on the time of day or month of the year. The spreadsheet model allows for these types of variation when estimating potential bill savings from the operation of a PV DSM system. The choice of discount rate for a commercial customer involves many factors. We have used in this analysis a rate of 12%, which represents a reasonable proxy for a typical US commercial customer's cost of capital.

In addition to bill savings, customers that invest in a PV DSM system also receive certain tax benefits. Current US tax policy permits a customer to deduct from their income equipment depreciation on a double declining balance basis (we used a double declining method over five years), as well as the interest incurred on a loan and O&M expenses. Equation (3) provides the calculations for estimating the annual net tax benefit.

$$NTB = CIT^{*} (DP + ID + OM - BS) \quad (3)$$

where

NTB = annual net tax benefit
CIT = customer marginal income tax rate
DP = annual depreciation
ID = annual interest on debt
OM = annual O&M expenses
BS = annual bill savings

Customers investing in PV DSM are also eligible in the US for a 10% tax credit for the purchase of renewable energy systems. These tax savings increase the attractiveness of an investment in PV DSM and are, therefore, treated as a component of the benefits stream.

The main benefit for a utility that invests in PV DSM is its avoided cost resulting from the operation of the system. Utility avoided costs include two components: avoided capacity and avoided energy costs. Equation (4) describes the calculation of annual avoided costs.

$$UAC = (kW_{cr}{}^{*}\ ACC) + [(kWh_{an}{}^{*}\ ULL)\ {}^{*}\ AEC] \quad (4)$$

where

UAC = annual utility avoided cost
kW_{cr} = credited capacity of PV DSM system
ACC = utility avoided capacity cost
kWh_{an} = annual PV system output
ULL = utility line losses
AEC = utility avoided energy cost

Avoided capacity cost is based on the credited capacity of the system and a US$/kW value which represents the utility's marginal cost of additional capacity. Often US utilities use the cost of a combined cycle gas fired combustion turbine for this purpose. This type of generation unit is widely used to meet peak power requirements.

An avoided energy cost is usually stated in US¢/kWh and represents the cost savings that arise from the operation of the PV DSM system. If a gas fired combustion turbine is considered the avoided unit, the cost of natural gas, and any variable O&M, comprise the avoided energy cost. This value is multiplied by the annual kilowatt hour production of the PV DSM system to obtain the annual avoided energy cost. A fuel price forecast supplied by each utility is used to obtain this value for the 25 years that the system is in operation.

The effective cost of installing the PV DSM system for the utility is reduced on the basis of the utility's ability to depreciate system cost (in the USA, on a double-declining balance basis). This tax benefit, while not as large for US utilities as their customers, still constitutes an important offset to the initial capital cost of the PV DSM system to the utility.

Recently, several state regulatory authorities in the US have required utilities to consider environmental externality values when making resource selection decisions. Although there are disagreements about the most appropriate method for calculating externality values, most experts agree that the production of electricity from fossil fuels results in important adverse environmental and health impacts that are not factored into existing prices of electricity. To accommodate this policy trend, our model allows the user to establish environmental externality values either based on US$/tonne of avoided emissions or as a US¢/kWh adjustment. The analysis presented here includes a modest environmental externality benefit based on the value of tradable SO_2 permits being auctioned in the US under the 1990 Clean Air Act Amendments. Currently, the selling price for an SO_2 permit is US$240 per tonne.

In addition to capital costs and O&M expenses, utilities incur carrying charges as a result of investing in a PV DSM system. Carrying charges equal the sum of annual requirements for return on investment, taxes, and other fixed overhead costs (Kahn, 1988). These were included in the calculations reported here, based on each utility's standard practice. All utility costs and benefits are discounted to their present values using the utility's after-tax average weighted cost of capital.[5]

Table 7 provides the benefit–cost ratios for customer and utility ownership options. These results suggest that the economics of PV DSM are currently more favourable for customer owners. This is due partly to the difference in tax treatment of capital investments available to utility customers in the US and to the relatively modest avoided costs of the five participating utilities.

It is also important to note that, in all five utility service territories, the potential benefits of dispatchable PV DSM are greater than those of non-dispatchable (ie non-storage) systems. When compared to the costs of each system, dispatchable options in all territories are closer to commercial viability. This underscores the importance of deploying PV in a dispatchable DSM mode over the more typical applications that emphasize maximization of energy output. The increased costs of a dispatchable system are more than offset to the customer by increased demand savings and to the utility by avoided capacity costs.

However, investment in PV DSM remains uneconomical, using a traditional engineering economics approach, for all five utility service territories. Our results are consistent with analyses performed by Hoff and Wenger (1992), which suggest that, currently, the cost of PV systems exceed their value as DSM applications for both utilities and customers when each undertakes the necessary investment alone.

[5]See Shimon Awerbuch's April 1995 article in *The Electricity Journal* for a critique of this discounting approach. Our spreadsheet model allows the user to specify an appropriate discount rate and, thus, Awerbuch's alternative discounting method can be employed, if desired. Because our interest is in comparing benefits and costs among the five case study utilities, we have adopted discount rates currently used by each case study utility to evaluate competing investments.

Policy options for promoting PV DSM

Although the above analysis illustrates that PV DSM is closer to commercial viability than previously thought, these systems are still not cost effective in the USA, based on accepted analytical methods. Innovative policies will be needed if investments in PV DSM are to become cost-effective in the near-term.

Non-traditional benefits of PV

Recently, much interest has been given to developing methodologies for estimating the value of PV as a grid-support technology. Several studies have shown that PV offers substantial value to utilities and their customers from the deferral of investments in transmission and distribution (T&D) equipment and increased reliability when PV systems are strategically sited within the utility's distribution system (Shugar *et al*, 1992). This benefit was not included in the above analysis.

In addition, it is widely believed that PV technologies offer other 'non-traditional' benefits that are not well understood or quantified, including modularity and reduced risk. Modularity refers to the ability to quickly respond to higher demand for electricity with capacity increments that are matched to the expected load increase. Traditionally, a utility builds large power plants based on projections of future demand. Experience has shown that these forecasts can be wrong, leaving a utility with uneconomically high reserves for periods of time. As a result, there can be an important benefit from having the ability to meet increasing demand in modular, comparatively small capital purchases (EPRI, 1994). Furthermore, investments in PV can offer benefits to utilities in terms of reduced risk from fuel price volatility and future environmental regulations (Awerbuch, 1995). Research is needed in these areas to better understand these 'non-traditional' benefits so that they can be included in cost effectiveness tests.

Complementary benefits of PV DSM systems

Dispatchable PV DSM can be engineered to offer complementary benefits in the form of emergency power, for example, uninterruptible power supply (UPS) and emergency lighting. UPS systems protect information that may be lost in the event of a power outage, allowing employees enough time to save data files and other vital information. Most large commercial buildings are required to install emergency lighting systems in stairwells in case of a power outage. Currently, capacity costs for these functions range from US$2500 to US$6000 per kilowatt (Byrne *et al*, 1995).

Table 8 PV DSM investment options: benefit–cost ratio comparisons (dispatchable)

	NMPC[a]	DP&L	ECUU	SMUD	AUSTIN
Utility owned	0.41	0.66	0.52	na	na
Customer owned	0.69	0.76	0.98	0.73	0.75
GIF without rebate	0.69	0.80	1.09	0.78	0.81
GIF with rebate	0.74	0.93	1.18	0.86	0.86

[a]Winter peaking; all others are summer peaking; na: these are muncipal utilities, therefore, the methods for estimating benefits and costs are different from those of investor owned utilities. Currently, methods are being refined to allow for meaningful comparisons.

Source: Center for Energy and Environmental Policy, University of Delaware.

Clearly, the value of dispatchable PV DSM systems would be enhanced if the complementary benefits of these systems were included in the analysis. Dispatchable PV DSM systems could be configured in an effort to meet these needs with little additional cost. These benefits have not been factored into the present analysis. However, future work will involve the development of methods for incorporating these complementary benefits into benefit–cost calculations as avoided costs to the customer.

Utility–customer partnership

To speed the penetration of PV into the DSM market, an innovative utility–customer partnership may also be considered. A Green Investment Fund (GIF) that has customers and utilities contributing to a fund for the purpose of purchasing PV DSM systems may serve this purpose, much in the same manner that 'green pricing' joins both parties in a common effort to make advance purchases of technologies that are currently not cost effective to the individual partners (Moskovitz, 1993). Both strategies are intended to encourage early sales of new technology in the hope that such sales will stimulate more rapid price reductions by renewable technology manufacturers.

Unlike green pricing, a GIF would not require premium rates. Instead, customers would be sought who are willing to forgo the bulk of potential bill savings that would accrue to customer owners of PV DSM systems and to invest, as well, a high percentage of the tax savings available to them. The commitments of bill and tax savings may be attractive to commercial customers who have an interest in promoting environmental values and/or technologies. The forgone bill savings would, in all likelihood, not be realized because (in most cases, at least) customer owned systems are not cost effective. And, if the utility partner can assume the initial capital cost (which would then be repaid from customer tax and bill savings), a customer's participation in a GIF partnership would involve no additional out-of-pocket expenses. The customer might retain a portion of the bill savings for allowing the PV DSM system to be installed on their premises. Although PV DSM would have to compete with other DSM options, the environmentally friendly nature of this investment may offer special advantages to certain customers.

Under a GIF arrangement, a utility may find the opportunity to dispatch the unit for system peak shaving advantageous. In this circumstance, a small rebate for the peak shaving value of the system might be paid and held in the fund. For a capacity constrained utility, a useful proxy for the value of peaking capacity is the avoided cost of a gas fired combustion turbine with the capacity factor set to zero. This is reasonable assuming that utility system peaks occur infrequently, and that the utility can take credit for the dispatchable peak shaving capacity of the system. Double counting of customer and utility benefits is avoided if, during the time the system is dispatched by the utility for peak shaving, no energy or demand savings are calculated. Certain utility peak management programmes utilizing customer sited engine generation operate in a similar fashion.

We calculated the net present value benefits and costs of PV DSM in the five case utilities' service territories under a GIF arrangement. Table 8 compares the benefit–cost ratios for three investment options: customer owned, utility owned and GIF. For the purpose of these calculations, we assumed that the customer contributed 80% of the potential bill savings and 100% of the tax savings available from the operation of a dispatchable PV DSM system. When the utility chooses to pay a rebate, its value was calculated as equal to the avoided capacity costs (at zero capacity factor) based on the credited capacity of the PV DSM system operating in each service territory. It is assumed that the full value of the rebate is dedicated to the purchase of the PV DSM system. It was also assumed that the utility would manage the fund and would be responsible for O&M (standard utility carrying charges were included in the cost of the system in recognition of the utility expenses–rebate payment, debt servicing and O&M). With these assumptions met, a GIF can be an effective vehicle for the development of PV DSM.

Conclusions

Evaluation of PV technologies needs to take into account several distinctive resource and technological attributes, as well as alternative mechanisms for the purchase of systems. Our research indicates that when these attributes are included in benefit–cost analyses of PV, the technology is closer to commercial viability than previously thought and may be currently cost effective for certain utilities with above average commercial rates. Further, we have shown that PV can offer utilities and their customers peak management capabilities, similar to existing peak management DSM programmes. Several policy options for promoting near-term markets for PV DSM are identified. Policies that encourage the incorporation of such non-traditional and complementary benefits of PV as reduced risk, increased modularity and emergency power service can mean the difference in whether the technology is judged to be economical. A particularly important finding of our research is that dispatchable PV DSM systems may already be cost-effective if they are configured so as to provide emergency power.

Finally, we have shown that an innovative utility/customer partnership in which benefits are pooled for the purpose of purchasing PV DSM systems may provide the needed vehicle for taking advantage of early market opportunities. Under this arrangement, the opportunity for PV to play a role in the utility DSM market is enhanced, while also capitalizing on the green appeal of the technology.

We are convinced that near-term markets for PV technologies can be realized. However, methods of valuing nontraditional and complementary benefits must be developed in greater detail. Cash flow and internal rate of return analyses also need to be performed, in addition to cost effectiveness tests. Finally, research is needed to better understand the policy issues surrounding the development of utility–customer partnerships and the role that green investments can play in fostering early adoption of the technology.

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