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Applications

Photovoltaics as a Demand-side Management Technology: an Analysis of Peak-shaving and Direct Load Control Options

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For photovoltaic (PV) technology to play an increasing role in the utility sector at its present price, the technology needs to be developed in a manner that is consistent with, and takes advantage of, the economics of the demand-side management (DSM) market. High-value applications in this direction are for photovoltaics to perform a DSM function either as a direct load control (DLC) device or as a peak-shaving option, which has the effect of raising the end-use efficiency of customers' electrical equipment. This paper describes two PV-DSM applications involving a water heater and an air conditioner studied at a residential PV test facility, Solar One House, located on the campus of the University of Delaware. A single 55-W PV module directly connected to an electric water heater was found to offset standby and mixing losses, resulting in a 2°C increase in water temperature at the end of the afternoon compared to the standard DLC (grid-disconnected) case. A conservatively sized PV array without storage could meet the house air-conditioning load over 97% of the time from noon to 3 p.m., but only 69% from 3 p.m. to 6 p.m. If a PV system is combined with an air-conditioning cycling program, success rates for supply of an air-conditioning load are greatly increased, meeting almost 100% of the load between noon and 3 p.m. and 85% during 3 p.m. to 6 p.m. Furthermore, our results suggest that a modest-size PV array with storage could significantly shave peak air-conditioning loads during 3 p.m. to 6 p.m., thus reducing the peak demand faced by a utility. Preliminary analyses support the economic compatibility of a PV system as a DLC device or a peak-shaving tool.

INTRODUCTION

The availability of solar energy in most parts of the USA during the summer appears to correlate well with the types of days on which utilities experience peak demand. Utility system peak loads tend to coincide with long, hot sunny days during the summer when high solar insolation is also

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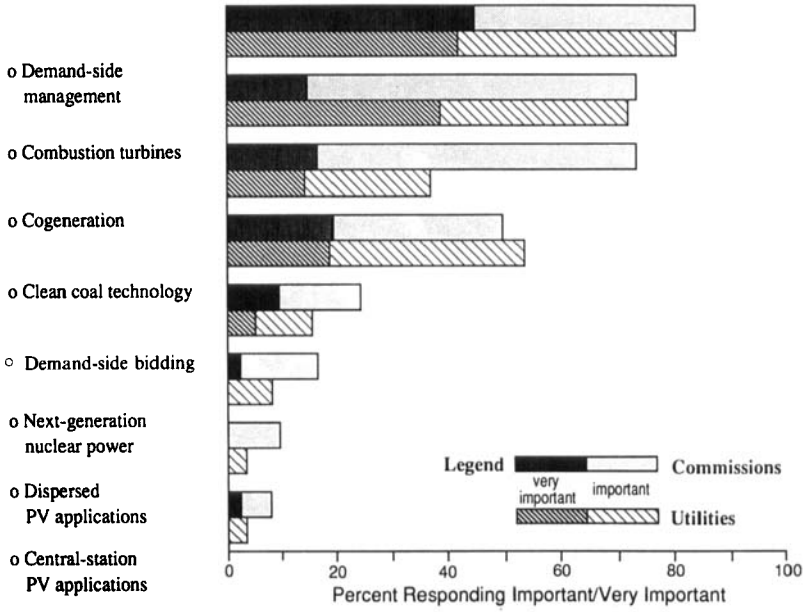

Figure 1. Alternatives for meeting electricity capacity needs (Source: Ref. 3)

available. Photovoltaic (PV) technologies could deliver high-value power to a utility system in a technically and economically comparable way to peak demand-side management (DSM) programs already in use in the US utility sector. In this role, photovoltaics can complement existing power sources and serve as a load management device. Photovoltaic technology's peak load reduction could be equal to, or greater than, that achieved by a high-efficiency appliance upgrade. The Sanyo Electric Co. in Japan has successfully developed and commercialized a solar-powered air conditioner with a 540-W PV array that could satisfy on average at least 50% of the power requirement by the air conditioner in the summer.[1] Developed as a direct load control (DLC) technology, photovoltaics could interrupt power loads greater than the array output and, thereby, be credited with load reductions sufficient to make it commercially viable.

To date, PV technologies have primarily been considered by utility planners as a power generation option. As such, the ability of photovoltaics to compete with other options is evaluated on its cost per unit of energy delivered ($\$\ kWh^{-1}$). In this comparison, photovoltaics requires significant cost reductions before it can become competitive with other generation options. Not surprisingly, utility managers and state regulators surveyed in 1990 and 1991[2,3] ranked photovoltaics below all other options in meeting capacity needs through to the end of the century, including next-generation nuclear power (Figure 1). By contrast, DSM was ranked as the most attractive option by the overwhelming majority of utility and state regulatory officials responding to the two surveys.

For photovoltaics to be a valued technology in the electric utility sector, DSM applications need to be identified that can provide distinctive market opportunities. In turn, this requires that photovoltaics is able to serve customer demands during the periods when utilities experience peak loads. In evaluating the future direction of PV technologies, the US Department of Energy (DOE) identifies utility peak power reduction technologies as the market segment where photovoltaics can be most competitive.[4]

This paper describes the technical results obtained from PV-DSM experiments sponsored by the National Renewable Energy Laboratory (NREL) during the summer of 1992, involving two important loads contributing to utility peak demand—water heating and air conditioning. The economic feasibility of these PV-DSM applications is also analyzed. For purposes of comparison in the PV-DLC tests, Delmarva Power's existing DLC programs for residential water heaters and air conditioners were utilized

as a reference case. The headquarters of Delmarva Power are in Wilmington, Delaware and serve most of Delaware and portions of Maryland and Virginia. The utility has an installed capacity of 2300 MW. Through its DLC programs, Delmarva Power intervenes in the operation of residential water heaters and air conditioners during days when the utility's higher peak demand is expected. By providing customers with financial incentives, the utility maintains the right to turn water heater power off for periods of up to 8 h per day and to cycle air-conditioning units at 15-min intervals by means of remote radio signal. For the PV peak-shaving analysis, a natural gas-fired combustion turbine (GCT) was used as the least-cost utility supply-side option. This technology is currently used by Delmarva Power to evaluate DSM options in the company's integrated resource planning and the calculation of avoided generation and energy costs. Many US utilities similarly rely on GCT technology to assess the economics of DSM options.

SYSTEM DESIGN

In order to evaluate the technical feasibility of PV-DLC options, tests were conducted under practical operating conditions. The tests, in cooperation with Delmarva Power, were conducted during the summer of 1992 at the Solar One House at the campus of the University of Delaware.

Solar One test facility

Solar One House is a combined residential dwelling and solar test facility built in 1973 to study solar thermal and electric systems on a residential scale. The building has 1350 ft^2 of living area and is very well insulated. The living area of the house consists of a living/dining room, two bedrooms, one and a half bathrooms, a kitchen and a utility room. The south-facing roof is sloped at 45°. In 1991, a 960-W_p array was installed, consisting of eight strings of three multicrystalline Si modules each rated at 38–40 W_p. One string was diverted for connection to the water heater, as described below.

Data acquisition and control system

A well-insulated (R12 value) 52-gallon electric water heater was installed exclusively for use in this study. A data acquisition system monitored indoor (house) and outside temperature and humidity, solar irradiance in the plane of the modules (using a calibrated Si detector), water-heater tank temperature, water flow and PV power into the water-heater element. The system also allowed active control of the air-conditioning fan and compressor and the water-heater flow. Delmarva Power monitored the 220-V AC power consumed by the compressor (3.3 kW), fan (0.4 kW) and water heater (4.5 kW), synchronized with the recording of total house electricity demand.

Photovoltaic connection to water heater

The bottom element, which is the primary heating element in a conventionally operated water heater, was temporarily disconnected from the grid from noon to 6 p.m. during the PV-DLC studies. The top element of the water heater was permanently disconnected from grid power and instead was directly connected to a string of three PV modules. The power from this string of the array was stepped down, using a resistor divider, to be equivalent to the output of a typical 55-W_p module. No inverter or maximum power-matching electronics was used. The output of the 55-W_p equivalent module was directly coupled to the top heater element.

The standard 12-Ω heater element on the top was replaced with a 19-Ω element to give better impedance matching and hence maximum power coupling to the array. This value was selected as a compromise to give good average power matching over the range of sunlight and temperature expected. Typical commercially available 55-W_p modules operating at 50°C and standard intensity have a resistance at maximum power of about 5 Ω. This resistance decreases approximately proportional to intensity.

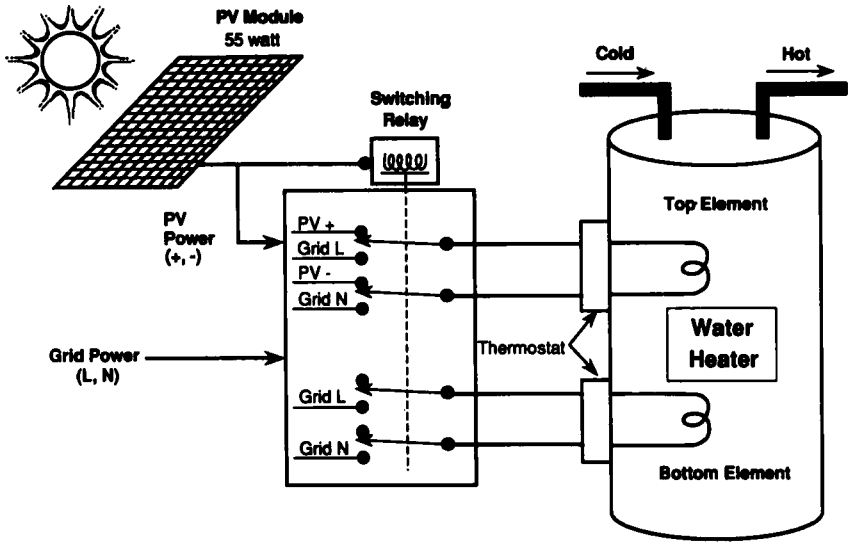

Figure 2. System diagram of PV-assisted water heater

Therefore, to obtain optimum impedance matching under realistic operating temperature (50°C) and intensity (800–900 W m^{-2}) would suggest an impedance of 6–7 Ω for the heater element. As we were using three modules in series, we selected a 19-Ω upper heating element. The maximum power delivered to the heating element under full sunlight conditions was observed to be 40–45 W. This power is 1% of the AC power used to heat the element in grid-connected mode. For actual applications using a single 55-W_p module, the top heater element should be only 6–7 Ω. A schematic diagram of a PV-assisted water heater is shown in Figure 2.

Photovoltaic/air-conditioning interface

The air-conditioning system was operated in one of three control modes from noon to 6 p.m. The compressor was forced off for 15, 17.5 or 20 min in every half-hour. Thus, the off–on cycles were 15–15, 17.5–12.5 or 20–10. Note that 15–15 is the utility standard for air-conditioner DLC programs. A given control mode was repeated for several days running to obtain results over a wide range of weather. Only days having peak temperatures exceeding 27°C were included in the analysis. Based on the experimental analysis, a PV-DSM air-conditioning system with storage capacity was evaluated for its possible contribution to meeting air-conditioning loads in the late afternoon (3 p.m. to 6 p.m.) when utility needs for peak shaving are high but the availability of solar energy is relatively low.

The major components of a PV-DSM system with storage for a building would be a PV array, an inverter to convert the DC array output to AC, a battery bank to store energy and various control and safety equipment. The output of this system would be connected to the building's power distribution system. The building would also be connected to the utility grid, as shown in Figure 3.

RESULTS OF PV-ASSISTED ELECTRIC WATER-HEATER TESTS

Several design-related weaknesses in the standard grid-connected water heater were observed during the water-heating experiment that affect its DSM performance. For example, the thermostat for the bottom element would have turned on after withdrawing as little as 3 gallons of water. The tank temperature measured in the top third did not change following this small withdrawal and yet the entire tank was reheated up to the set-point temperature, requiring maximum power consumption. Also, under quiescent

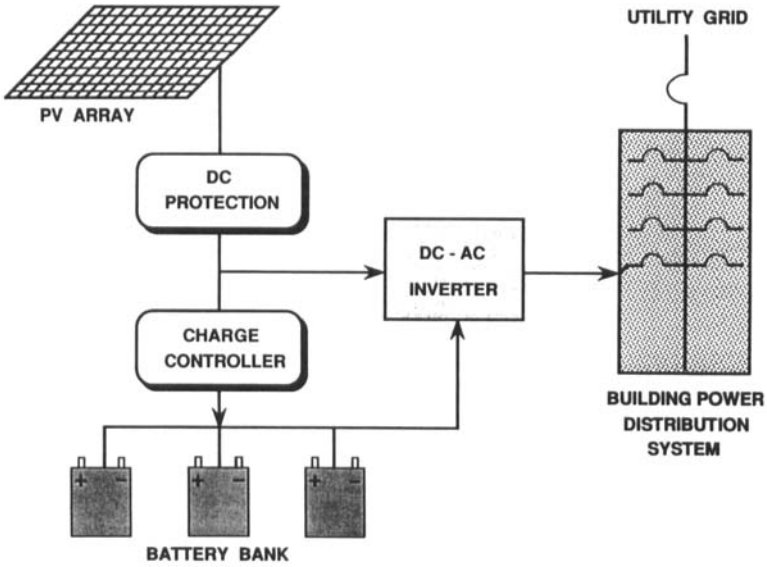

Figure 3. Conceptual drawing of a PV-DSM system

conditions of no flow, the bottom thermostat indicated that the unit would have turned on for approximately 2-min intervals just to offset standby losses. The bottom element required power three to four times for 2 min for noon to 6 p.m. This represents 400–600 Wh of energy consumption per unit. Together, these two observations suggest that the water heater must be switched off-grid completely during the afternoon for effective DSM. These weaknesses could be overcome by adjusting the thermostat's dead-band, or by inserting the thermostats in the water itself rather than on the outer surface of the tank. As shown in Figure 2, we propose a disconnect switch that is activated by the PV panel itself. When sufficient PV power is available, the bottom element will be disconnected and the top element will be connected to the PV module.

Water-heater tests were conducted by heating the tank with the grid-powered bottom element to 52°C. This element was disconnected at noon, and 10, 15 or 25 gallons of hot water were removed to simulate midday water usage. The 25 gallons were removed to simulate distributed usage, i.e. 10 gallons at noon followed by 5 gallons at 1 p.m., 2 p.m. and 3 p.m. Thus, cooling of the water heater occurred due to standby losses and mixing of the 10, 15 or 25 (10–5–5–5) gallons of cool water. Photovoltaics was the only power input throughout the 6-h period of electricity interruption. Water-heater temperature was monitored by a thermocouple located in the top third of the tank (16 inches from the top). For reference, the system was also operated on some days in a typical DLC-only mode, with no PV or grid power input from noon to 6 p.m. The results include sunny and partly sunny days, where the insolation at 1 p.m. ranged from 830 to 1100 W m^{-2}.

Figure 4 shows the range of water temperatures during the afternoon from noon to 6 p.m. for the PV-assisted compared to the DLC-only cases for 10–15- and 25-gallon withdrawals. The results of these tests show that a PV-assisted water heater will have a smaller heat loss after 6 h than its DLC counterpart. As the experimental data indicate, the temperature in the tank would remain above the threshold temperature (i.e. the temperature at which the unit would turn on for an extended period of time), except for the 10–5–5–5 hot-water withdrawal scenario. Because a water heater normally draws 4500–4800 W of grid electricity, a 55-W PV panel could contribute considerable DSM value to a utility.

Clearly, one 55-W_p PV module can be effective in offsetting losses, leading to a 2°C increase over the DLC case by 6 p.m. This shows that a single PV module is effective in providing positive value to the customer (i.e. hotter water). Table I gives the range of water-heater temperatures observed for different operating modes. The data represent 10 days each of 10- and 15-gallon withdrawal at noon.

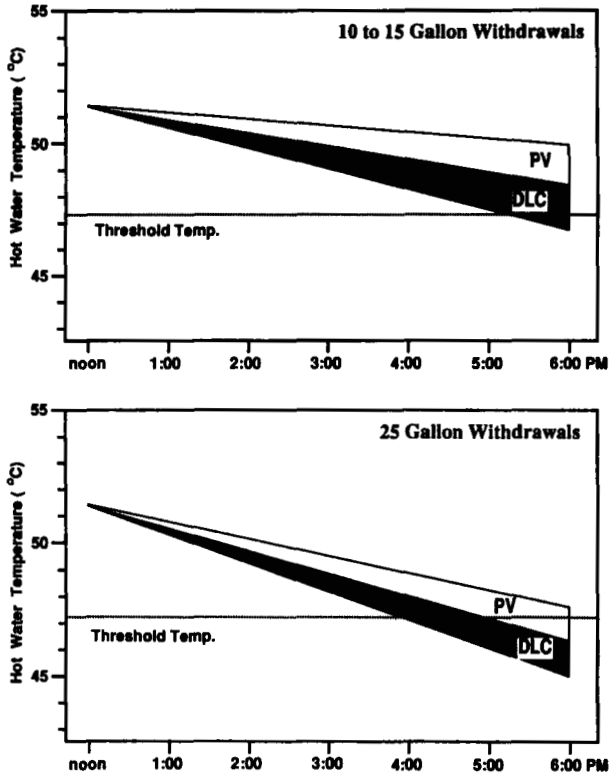

Figure 4. Effects of PV for 10–15-gallon withdrawals. Note: range of solar insolation values at 1 p.m. (DST) = 830–1100 W m^{-3}

Table I. Water temperature at 6 p.m. for 10- and 15-gallon withdrawal at noon[a]

Condition	Range of temperature (°C)
DLC (no grid or PV)	46.7–48.3
Grid-connected	46.7–48.9
PV-assisted	48.3–50.0

[a] Water temperature at noon prior to withdrawal was 51°C.

Figure 5 shows the solar intensity and water temperature for 2 days following a 15-gallon withdrawal at noon. The water-heater temperature remains above 50°C all afternoon on 30 August (sunny days). The water-heater temperature falls off steadily after 2 p.m. on 18 September (partly sunny day), corresponding to the reduction in intensity due to the clouds. The PV power delivered to the element actually falls more rapidly than the intensity because of the lack of maximum power tracking. For example, when the intensity decreases from 900 to 300 W m^{-2} (33%), the PV power decreases from 42 to 6 W (14%).

The power from a single 55-W_p module could only provide minimal benefit if it were applied to the entire 52-gallon tank. But, in these experiments, photovoltaics only heats the top third of the water heater, which is approximately 15 gallons. However, this is sufficient to offset standby and mixing losses. As the PV-heated water would be the first water used, the warmer water represents an added value

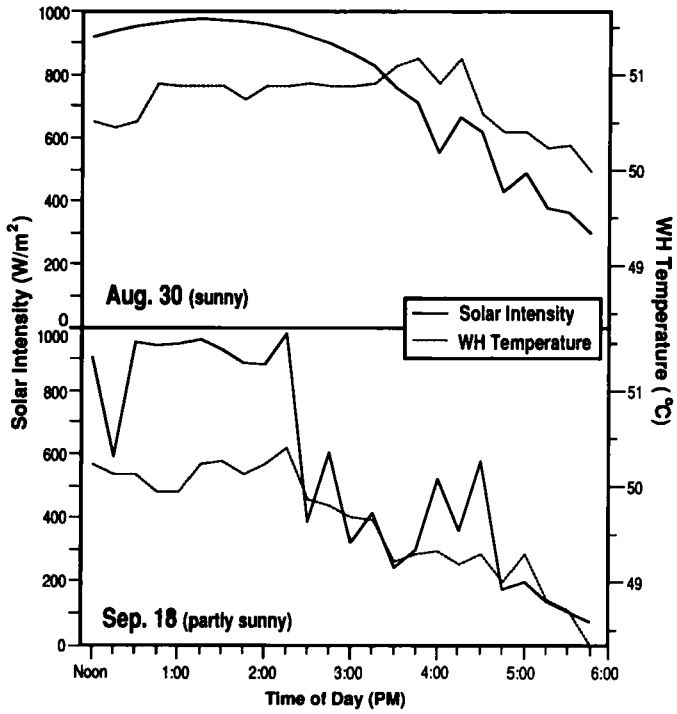

Figure 5. Water temperature and solar intensity on two summer days

compared to the DLC case for the utility customer whose water heater would be off-grid all afternoon. In conclusion, a customer would receive superior service from a PV-assisted water heater.

RESULTS OF AIR-CONDITIONING TESTS

The air conditioner was not directly operated from PV-generated electricity. Instead, the air-conditioning power consumption was compared to PV generation to determine whether a PV system could supply air-conditioning energy requirements in the Mid-Atlantic region of the USA (consisting of southern New Jersey, eastern Pennsylvania, Delaware, Maryland, Washington DC and northern Virginia). A hypothetical array was sized to meet the air-conditioning load of 3.7 kW (400 W of fan and 3300 W of compressor). The PV array needed to provide 3.7 kW under *real* conditions would need to be 5.4 kW_p, as shown below.

In this estimation, we accounted for various losses and gains to arrive at a nominally rated DC array power (P_0) as measured under standard rating conditions of intensity (I_0) of 1000 W m^{-2} at 25°C. The three sources of significant losses are: the inverter conversion efficiency (L_{ac}); the actual operating temperature (L_t) compared to the rated ideal temperature (25°C); and the intensity of the array (L_i) compared to the ideal intensity (I_0 = 1000 W m^{-2}). A gain in output by decreasing the angle of the array from the horizontal was calculated to be insignificant (<1%) because the roof is already pitched at a nearly optimum slope (45°).

From the inverter manual and our own measurements, L_{ac} was determined to be in the range of 0.92–0.96. A value of 0.95 was chosen for L_{ac} in our hypothetical sizing of the array. The temperature coefficient of the power output is typically −0.4% °C^{-1}. Modules are rated at 25°C, but typically operate at 25°C above the rated temperature, leading to a loss factor L_t of 0.90 of the rated power. An intensity (I) of 800 W m^{-2} turned out to be reasonable for mid-afternoon, hazy but mostly cloudless skies from our data. Losses due to real intensity (L_i) were determined to be 0.8 compared to the rated intensity.

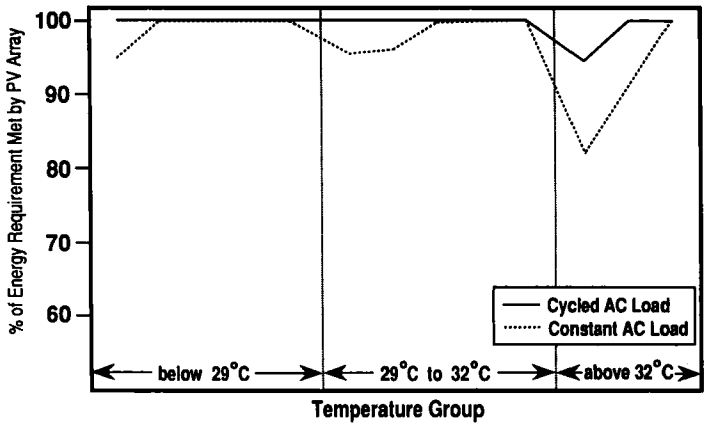

Figure 6. Success rates for PV supply of air-conditioning loads: 29 July, 1992–31 August, 1992 (noon to 3 p.m.). Range of solar insolation values as in Figure 4

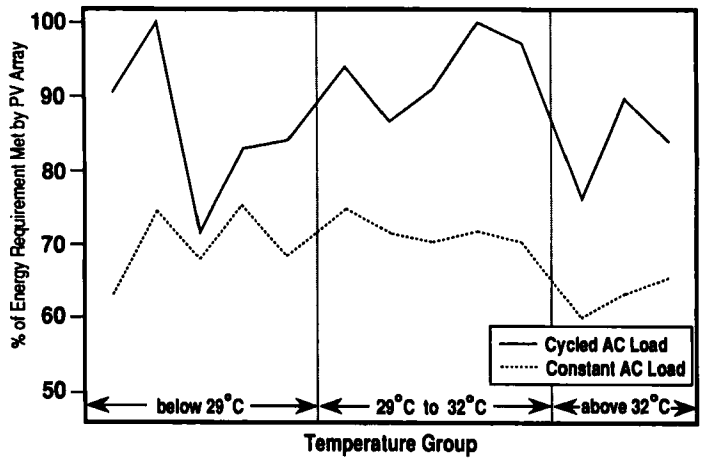

Figure 7. Success rates for PV supply of air-conditioning loads: 29 July, 1992–1992–31 August, 1992 (3 to 6 pm). Range of solar insolation values as in Figure 4

Therefore, the nominal array size (P_0) needed to produce P (3700 W) is

$$P_0 = P/(L_{ac} \times L_t \times L_i)$$

$$P_0 = 3700\ \text{W}/(0.95 \times 0.90 \times 0.80) \sim 5400\ \text{W}$$

where L_{ac} = AC losses, L_t = thermal losses and L_i = intensity losses.

The actual array output (P) would be related to the pyranometer intensity (I) as

$$P = (P_0 \times L_{ac} \times L_t) \times (I/I_0) = 4.6 \times I$$

The output of this hypothetical array was obtained by scaling up from the measured pyranometer data (4.6 times). Using the estimated solar array output, we computed the percentage of time between noon and 3 p.m., and between 3 p.m. and 6 p.m., that the PV system could satisfy the instantaneous power demands of the air-conditioning system under a variety of weather conditions. Results were analyzed both for a continuously operating air-conditioning system and for one that was cycled using the off–on DLC control mode of 15–15. Figure 6 and 7 show the success rates from noon to 3 pm and from 3 to 6 pm, respectively, for a PV supply of air-conditioning loads from 29 July, 1992 to 31 August, 1992 versus the maximum daily outdoor temperature.

Between noon and 3 p.m. the array supplied around 97% of the power needed, but between 3 p.m. and 6 p.m. this fell to 69%. This latter time interval is important for DSM because this is when peaking typically occurs, especially in the northeastern part of the USA.[5] However, by combining a PV-assisted air-conditioning system with an air-conditioning cycling program, photovoltaics' success rates for supply of air-conditioning loads are significantly improved, meeting 100% of the load requirements during noon to 3 p.m. (except for 1 day when the array supplied 95% of the required loads at above 32°C). Between 3 p.m. and 6 p.m. it supplied 88% of the air-conditioning loads.

The results obtained while operating the house air-conditioning system in different DLC modes suggest acceptable increases in temperature (2°C) in the late afternoon, despite having restricted intervals of cooling. These results are significant for PV operation of air-conditioning systems for DSM. They show that a modest-size PV system with storage could operate the air conditioner from 3 p.m. to 6 p.m. (i.e. during late afternoon peaking) with only a modest increase in inside temperature. For example, the air-conditioning system could operate for 3 h in the 20 min off–10 min on mode using only 60 min worth of electrical energy. The air-conditioning unit at Solar One House uses about 3.7 kW; therefore, 3.7 kWh of energy would operate the unit in such a mode for 3 h. A 1 kW array produces this much energy over the day after accounting for real operating losses (temperature, AC inverter, etc.). Thus, the PV array need not be sized to operate the air-conditioning unit continuously over the afternoon. Trade-offs between array size and storage, and interval of control should be considered.

ECONOMIC FEASIBILITY

The cost of a fixed flat-plate PV system is estimated to be \$6500 kW^{-1} (with no storage). In the current situation, the installation of a PV system is not economically viable for utilities because its cost is three times greater than its value to them.[6] Similarly, customers at this time have little economic basis for choosing to install a PV system connected to the grid. In such an installation, the economic value to the customer is in the form of reduced energy and demand bills and increased tax benefits derived from depreciation, interest deduction and tax credits on the PV investment. Studies show, however, that even in the case of high retail electricity rates, favorable tax treatment and an optimally sized PV system, the cost to a customer tends to be greater than its value.[6] Furthermore, some utilities have been reluctant to allow PV interconnection for safety reasons, either prohibiting the customer from having net metering or imposing expensive interconnection costs upon the customer.

These problems might be solved by a partnership between the utility and the customer in which the utility offers rebates and other incentives to the customer as part of a utility-sponsored DSM program. Like other DSM programs, the utility would get energy, capacity and distributed benefits from the PV system installed by the customer. These benefits would need to exceed the utility's costs in the form of lost revenues and customer incentive payments. From the customer's perspective, the economic value of the PV system would include reduced demand and energy charges plus incentives offered by the utility. These would have to exceed the installed cost of the system for a customer's investment to be economically justified. However, photovoltaics economics in this case turn out to depend significantly upon the availability of tax benefits to the customer and, currently, are not sufficient to warrant investment.[6]

A second partnership alternative is for the customer to contribute a part of all of their bill savings earned from the operation of the PV peak-shaving unit to an investment fund managed by the utility for the purpose of purchasing PV-DSM systems. In this alternative, the utility would also contribute to the investment fund. Its contribution would be set at an amount equal to the energy, capacity and distribution benefits that it would derive from the operation of the PV system. An economic analysis of this alternative has been completed using levelized present value of revenue requirements methodology (PVRR),[7] which is a standard method of economic valuation in the utility industry.[8] The analysis assumes that payment of the capital cost of the system is shared by the utility and customers. The utility's share is equal to the avoided cost of a GCT peaking unit (which is typically the lowest cost peak supply option for American utilities). The customer's share is set at an amount equal to some portion of the reduced

monthly demand and energy charges resulting from the operation of the PV-DSM system. Under this partnership arrangement, the pooled customer and utility shares would have to be equal to the initial capital cost in order to justify investment.

It is assumed that the utility finances the initial cost of the system, with the customer's potential bill savings used to pay off a portion of the investment. This arrangement avoids the pitfall of the utility having to address the possibility of shrinking energy sales. By recovering its investment in DSM directly from those customers benefitting from it, the utility does not have to burden its other ratepayers with increased costs. Such an arrangement casts the utility in the role of energy service provider. It invests in, and profits from, load reduction and not only through energy sales. This can only be achieved through a partnership between utilities and customers of the type proposed here. In this partnership arrangement, there are no utility lost revenues and, unlike many conventional DSM programs, free-rider and snap-back effects[9] are avoided.

Economics of PV-assisted water heaters

Financing for PV-DLC applications could draw from two sources—the rebates normally paid to DLC participants and the bill savings earned by customers. Effective use of these funds would probably require the development of a utility–customer financing partnership. A partnership arrangement may be important for PV-DLC programs to maximize the economic value to utilities and customers, creating the conditions for investment in cost-effective PV-DSM. Our economic analysis shows that a PV-DLC program directed at the interruption of water-heater loads can be cost-effective in comparison to conventional DLC approaches. To be competitive, PV-DLC programs would need to receive a rebate from the utility of \$300 and the customer would need to contribute \$150 for the purchase and installation of a 55-W_p module that would be designed to operate as a DLC device on a residential water heater.

The utility's assumed contribution of \$300 is within the range of rebate incentives currently offered by utilities, particularly in the residential sector. The DSM market has three distinguishable segments: one segment mainly involves lighting programs with relatively low rebates (\$100–\$200) directed almost exclusively to the commercial and industrial sectors; a mixed applications segment targeting heating, ventilating and air conditioning (HVAC) and lighting loads with rebates in the \$200–\$300 range; and a third segment dominated by programs aimed at reducing peak loads presented by residential and commercial air conditioners and residential water heaters with relatively high rebates (\$300–\$500). This last segment includes utility DLC programs.[10]

Our estimate of the cost of a PV-DLC water-heater program for the Delmarva Power service territory suggests that it could be competitive with existing DLC programs for water heaters operated by utilities. The levelized PVRR computed for each of these options are presented in Table II. In this economic calculation, the capacity saved per PV-DLC or water heater (WH)-DLC installation is assumed to be 360 W (instead of the 4500-W rating of the equipment) because water-heater interruptions typically occur at times of low hot water usage by residential customers.* Variable operation and maintenance costs for both PV-DLC and WH-DLC are assumed to be negligible.

The respective levelized PVRRs for the DLC water-heater program and a GCT are \$176 and \$172 $kW \cdot year^{-1}$, while the levelized PVRR for a PV-DLC water-heater program is \$187 $kW \cdot year^{-1}$. We estimate that ratepayers participating in the PV-DLC program would realize bill savings of approximately \$40 per year, equivalent to a payback period of under 4 years on their \$150 contribution. Thus, the economics of PV as a DLC tool could be sufficiently attractive to encourage utility and customer interest. Of course, there are a number of alternatives that may be more attractive, depending on utility and customer goals. These include solar hot-water systems, water-heater insulation upgrades and switching to gas-fired heaters.

* Only a fraction of water heaters in residential areas are found to be 'on' during the interruption period of noon to 6 p.m. Only a fraction of these voluntarily participate in the DLC program. Consequently, the savings in watts per DLC installation will be much less than the power rating of the water heater. A summer pilot study by Delmarva Power found that savings averaged 360 W per DLC installation. This value is consistent with findings from other utilities (see *1988 Survey of Residential Sector Demand Side Management Program*, EPRI Report CU-6546, pp. 6–16).

Table II. Illustration of PV as a DLC option for water heaters (WH)[a]

	Units	WH-DLC	WH-PV	Combustion turbine
Capital cost per installation	($)	$200	$300	$45.5 million
One-time promotional costs	($)	$21	–	–
Annual incentive	($)	$12	–	–
Fixed O&M	($ kW·year^{-1})	–	–	$0.80
Variable P&M	(¢ kWh^{-1})	–	–	1.0
Book life	(Years)	15	15	30
Tax life	(Years)	7	7	20
Property tax rate	(%)	–	–	0.2%
Capacity saved/produced per installation	(kW)	0.36	0.36	104 000
Av. annual heat rate	(BTU kWh^{-1})	–	–	12 500
Levelized PVRR	($ kW·year^{-1})			
Fixed costs		$125	$187	$67
Variable costs		$51	–	$105
Total		$176	$187	$172

[a] All monetary values shown are for 1992. Annual escalation rate is assumed to be 4.5%. The after-tax discount rate is 9.45%. The book and tax lives are based on current Delmarva Power practice. This comparison assumes that the DSM equipment would be replaced at the end of its 15-year book life. A water heater is assumed to have a 52-gallon capacity with R-12 insulation, and a power demand of 4.5 kW. A PV power supply is approximately a 55-W_p panel at 0.67 kW m^{-2} insolation. The total cell area is dependent on efficiency.

Economics of dispatchable PV peak-shaving systems

A second PV application analyzed with our partnership model involves a hypothetically sized, dispatchable 10-kW PV peak-shaving system deployed at commercial buildings. The analysis solved for the required installed price of a PV-DSM system to make the investor indifferent between PV and least-cost electricity supplied from the grid. This 'break-even' analysis determines how close the benefits provided by PV-DSM systems are to the costs of such systems. The purpose of this analysis is to determine what regulatory and financial conditions would allow the realization of the maximum possible benefits from a dispatchable PV-DSM system, as well as to indicate at what level of cost such a system may become economical.

The benefits used in this analysis are bill savings and avoided costs. Bill savings represent real monetary gains that would accrue to customers under existing electricity prices (including both energy and demand charges). Under normal conditions (i.e. customer ownership of the PV system and no special arrangements with the utility), bill savings would represent a net cost to the utility (as lost revenue) and would have to be deducted in a total cost–benefit calculation. Under the proposed partnership arrangement, however, these savings to the customer (or at least a significant portion thereof) would be returned to the utility to help finance the purchase of the PV-DSM system. Under our proposed partnership arrangement, the utility is, in effect, selling the electricity generated by the PV-DSM system to the customer at the utility's regular energy and demand rates. These rates are not based on the costs of the PV-DSM system and are not representative of what the full price of PV generation might be. Charging customers the full price of PV generation is inappropriate for this analysis as it would imply utility ownership and operation of the system with no contributions by customers. Such an arrangement may be attractive to commercial customers who would find value in participating as partners with their utilities in what we term a 'green investment' strategy.

The estimate of utility benefits used in this analysis is the avoided cost of additions to conventional peak generating capacity. This is the value typically used in cost–benefit analyses for conventional DSM programs and would reflect the reduced capacity requirements as a result of the operation of the PV-DSM system. While it may tend to overestimate the benefit in some cases, it is the appropriate reference case for capacity-constrained utilities. Such utilities find themselves obliged to either build additional generating capacity or invest in DSM measures. Thus, the full avoided cost of conventional peak

generating capacity represents the portion of the investment in the PV-DSM system that utilities would be willing to contribute.*

The break-even point in the economic analysis is a function of PV system's credited capacity (described below), the level of demand and energy charges paid by commercial customers and the availability of the solar resource. Alternative rate structures, dispatch hour requirements, credited capacity amounts and annual solar insolation levels were introduced in oder to gain an understanding of the sensitivity of PV-DSM's economic value. Three rate structure scenarios were used: a low demand charge scenario ($100 kW·year^{-1} demand charge and 3.0¢ kWh^{-1} energy charge), which is typical of utilities with surplus generating capacity and low fuel costs; an intermediate demand charge scenario ($158 kW·year^{-1} demand charge and 3.6¢ kWh^{-1} energy charge), which corresponds to the current rates charged commercial customers by Delmarva Power and is in the middle range of US utility rates; and a high demand charge scenario ($200 kW·year^{-1} demand charge and 6.0¢ kWh^{-1} energy charge), which represents utilities with supply deficits and high fuel costs. Several capacity credit options were considered. The range included: a non-dispatchable scenario in which a 10-kW PV-DSM system with minimum battery storage (< 1.5 kWh) is credited with an 8.5 kW reduction in building load; and a dispatchable scenario in which either a moderate level of storage (4–5 kWh) or a load control device is added to the 10-kW system, resulting in a capacity credit of 16.3 kW of system load reduction. Several dispatchable scenarios were analyzed with dispatch hour requirements varied from 3 to 6 h (fewer dispatch hours yield higher capacity credits, owing to the fact that the stored energy is released over a shorter period of time). Finally, the average annual sunhours were varied from 10.0% to 15.0%, which approximates the middle and lower range of solar insolation rates in the Mid-Atlantic region.

Figure 8 summarizes the results of our analyses under these different scenarios. Depending on the credited system capacity and rate structure, the allowable capital cost for a dispatchable 10-kWp PV-DSM system ranges from $2600 to $4600 kW^{-1}. For a PV-DSM system with a credited capacity of 16.3 kW, the break-even capital cost would be between $3800 and $6900 kW^{-1}. The break-even PV-DSM system cost of $6900 kW^{-1} is approximately 70% of current estimates of PV-DSM system costs (including storage) of $9900 kW^{-1}. (This estimate was prepared by AstroPower for the test facility installed by Delmarva Power during the summer of 1993.)

CONCLUSIONS

Our analysis suggests that PV-DSM programs, involving residential water heating, air conditioning and commercial building demand, are technically feasible and near commercial viability. In the residential water-heating application examined here, PV-DLC was found to be competitive with existing utility programs. In the case of a dispatchable PV-DSM application, the benefits generated by this option reach as high as 70% of the current costs for an installed system of this type. The range of installed purchase prices of $2600–$6900 kW^{-1} (including storage) in the peak-shaving case indicates that photovoltaics is much closer to commercial viability than normally thought. By reducing costs of major PV system components by 30% (which is well within industry and government expectations for the next 2–5 years), dispatchable PV systems could soon emerge as cost-effective DSM options for commercial buildings.[11,12] The introduction of environmental and fuel risk factors into utility calculations, continued movement toward real-time electricity pricing and the creation of renewable energy tax credits and/or 'green pricing' opportunities for customers will all enhance the competitiveness of the PV-DSM applications discussed here.

* An anonymous reviewer of this article raised a concern about the inclusion of both the avoided utility costs and customer bill savings as benefits in a benefit–cost calculation. The concern is that this results in double counting, because utility rates already take into account the costs to serve a customer. Under the partnership model that we are proposing, this would not represent double-counting since the avoided cost contribution is figured only on the dispatch function of the PV-DSM system, while the potential bill savings to the customer are calculated for the periods when the system is not under a utility dispatch requirement (i.e., non-peak days).

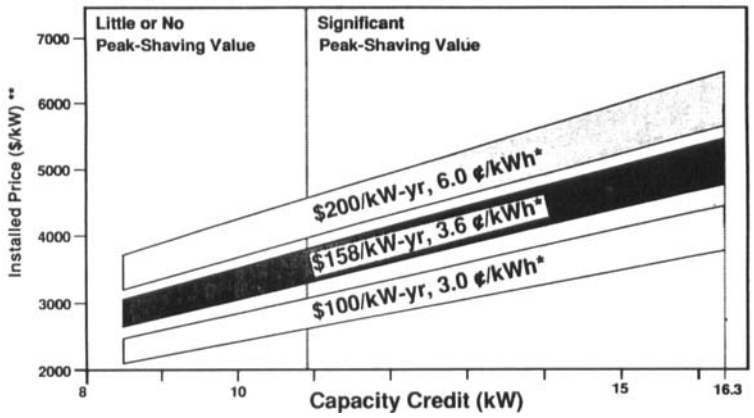

Figure 8. Break-even installation costs of a dispatchable 10-kW PV peak-shaving system with storage: commercial building application. * Range of utility demand and energy charges considered in the break-even analysis. ** Capital costs only (no carrying charges). For dispatchable systems, the following are included: 50 kWh of battery storage, 10 kW of PV modules, DC–AC inverter, charge controller, wiring and array structure. For non-dispatchable systems, all of the above are included except that storage is reduced to 10 kWh. Assumptions: 9.48% after-tax discount rate; avoided cost (levelized) equal to simple cycle, gas-fired turbine ($149 kW·year^{-1} at 10% capacity factor; $190 kW·year^{-1} at 15% capacity factor

The use of photovoltaics as a DSM tool appears to provide more value to utilities and customers compared to most supply-side applications. Furthermore, unlike most other DSM technologies, PV-DSM offers benefits that are easily and directly measurable. Through partnership arrangements, PV-DSM can also avoid problems such as rate gaming, free riders and snap-back effects. In summary, the benefits made possible by the application of photovoltaics in a DSM role are considerable and place PV technologies much closer to large market penetration than is conventionally assumed.

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