Public Utilities
Fortnightly

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A Dispatchable Peak-Shaving Option

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REPRINTED FROM
PUBLIC UTILITIES FORTNIGHTLY
SEPTEMBER 1, 1995
VIENNA, VA

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A Dispatchable Peak-Shaving Option

PV technology combined with storage offers a cost-effective alternative to capacity additions.

By John Byrne, Young-Doo Wang, Ralph Nigro, and Steven E. Letendre

Until recently, both regulators and electric utilities have considered photovoltaic (PV) technology (i.e., solar cells) an unattractive energy-supply option because of its relatively high cost. Now, however, a number of utilities have shown interest in using PV for peak-shaving. Analyses of the Mid-Atlantic region (which has an average insolation rate of only 1,550 Kwh/m^2/yr) indicate that PV deployed in a peak-shaving role is cost-effective if modest targets for improved efficiency and cost reductions in PV modules are met, or if nontraditional environmental and distribution benefits are included.

A PV system's peak load-reduction capacity is ordinarily equal to the power it generates at any moment. However, integrating PV technology with storage makes it possible to displace a load greater than an array's output at peak demand periods. This application is currently being tested at Delmarva Power & Light Co. (DP&L), and will be tested at four additional sites in 1995 as part of the PV:BONUS program under a contract with the U.S. Department of Energy.

The dispatchable PV peak-shaving system under investigation at DP&L incorporates energy storage and focuses on commercial building applications to take advantage of the demand-sensitive rate structures used to price electricity services to commercial customers. The presence of demand (kilowatts) as well as energy (kilowatt-hours) charges means that commercial customers can realize the advantages of peak-shaving through bill savings. Often, demand charges constitute a greater portion of a commercial customer's bill than energy charges. Because PV in a peak-shaving role is similar to (and will have to compete with) conventional demand-side management (DSM) technologies, we will use the term PV-DSM to represent the application.

Demand savings are maximized by designing PV-DSM to offer dispatchable load-reduction capacity to utilities. Dispatchability of a PV-DSM system can be achieved either by integrating the solar component with a direct load-control device or by incorporating some form of energy storage. Possible forms of storage include batteries and cool storage (for a system designed to manage air-conditioning loads). The advantage of storage is that it avoids the need to interrupt service.

The cost-effectiveness of a PV-DSM system depends upon a number of variables, including the capacity reduction credited to the system, the level of demand charges, and the amount of solar energy available over the course of a year. A regression analysis based on 72 different cases demonstrated that credited capacity is the most important variable in determining the economic value of PV-DSM. The credited capacity of dispatchable PV-DSM is sensitive to the number of hours per day the system will be expected to be available for dispatch. The larger the number of hours, the smaller the power output the system will be able to maintain—and thus, its credited capacity.

Shaving Commercial Building Demand

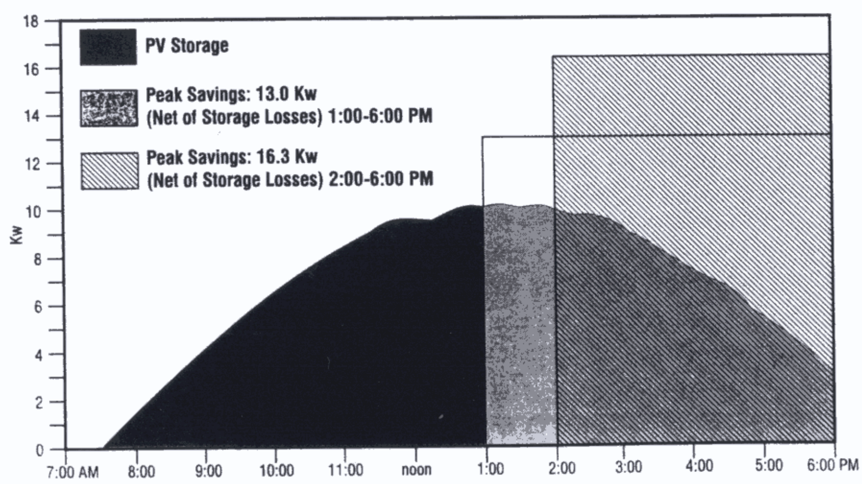
The PV-DSM system is designed to shave commercial building demand during periods of utility system peak load. The system stores the energy produced by the PV array during periods of relatively low demand (early to mid-morning). By sizing the battery bank so that it can be comfortably charged by the morning sun available on a peak demand day (this is done by using a "worst case" peak demand day as the reference case), the system can deliver reliable peak-shaving capacity to utilities. In the Mid-Atlantic region, for example, a system incorporating a 10-kilowatt (Kw) PV array can consistently provide 16.3 Kw of power for a four-hour period during summer months, with only a modest amount of storage capacity (the equivalent of 50 kilowatt-hours (Kwh)) *(see Figure 1)*.

During the four-hour dispatch period, 30 percent of the load reduction achieved by the PV-DSM system comes from current output of the PV array and 70 percent from the stored PV energy. If, however, the system were required to be dispatched for five hours (for example, from 1:00 p.m. to 6:00 p.m., DST), it could only deliver 13.0 Kw of peak savings. Because the system is designed to fully charge its batteries between 7:30 a.m. and 1:00 p.m., it can be dispatched during consecutive peak days. Experiments conducted at DP&L during the summers of 1993 and 1994 demonstrated the system's ability to meet "back-to-back" dispatching requirements.

We conducted a net present value (NPV) analysis to estimate the value of dispatchable, peak-shaving PV-DSM systems for both utilities and customers. If a utility were to purchase such a system, the benefits would equal the avoided cost of additions to conventional peak generating capacity (the value typically used in cost-benefit analyses for conventional DSM programs). While it may tend to overestimate the benefit in some cases, avoided cost is the appropriate reference case for capacity-constrained utilities that find themselves obliged to either build additional generating capacity or invest in DSM measures. Thus, the avoided cost of conventional peak generating capacity represents the level of investment in PV-DSM that utilities would be willing to make.

If a commercial customer chose to purchase a PV-DSM system, its direct benefit would equal the reduced monthly demand and energy charges resulting from operation of the PV-DSM system. Bill savings represent real monetary gains that would accrue to customers at prevailing electricity prices. Under customer ownership of the PV system, bill savings

Figure 1. Projected peak load savings for a commercial building served by a 10-Kw PV-DSM system.



Sources: Center for Energy and Environmental Policy and Institute of Energy Conversion, University of Delaware; Delmarva Power. Summer 1992 PV-DSM test results.

could represent a net cost to the utility in the form of "lost revenue."

Table 1 summarizes the NPV of benefits and costs for each ownership option if a PV-DSM system were sited in DP&L's service territory. A credited capacity value of 16.3 Kw was used for a system that combines a 10-Kw PV array with 50 Kwh of battery storage based on ground source measurements of irradiance matched to utility peak load during Summer 1992. In the case of utility ownership, a benefit-cost ratio indicates that only 66 percent of current costs can be covered by the benefits of a peak-shaving PV system.* The utility receives total NPV benefits of $95,940, compared to NPV costs of $145,170. The NPV costs for the utility consist of three components: capital costs, operations and maintenance (O&M) costs, and carrying charges. Capital costs include $8,500/Kw for the PV array, power-conditioning system (PCS), and array structure (installed), plus $200/Kwh for battery storage. O&M costs include $500 every five years for overhauling the PCS, and $150/Kwh every seven years for battery replacement. Utility carrying charges equal the sum of annual requirements for allowable return, taxes, depreciation, and other overhead costs.

Customer ownership and financing of the PV-DSM system produces a higher benefit-cost ratio. Under this option, the customer would retain all bill savings resulting from operation of the PV-DSM unit. Tax benefits include an accelerated depreciation deduction and a 10-percent renewable energy tax credit (established by the Energy Policy Act of 1992), neither of which is available to utilities. Customer NPV costs include the capital and O&M costs described above in the utility ownership option. The NPV of O&M costs differs because the customer is assumed to employ a higher discount rate (12 percent) than the utility (7.99 percent). It is also assumed that the customer would not attach carrying charges to this investment. The combined benefits to customers ($84,730) were found to be 76 percent of system costs ($111,040). This result suggests that the economics of PV-DSM are more favorable for customer-owners, mostly due to the special tax benefits.

Table 1
Benefit Cost Comparison of Utility- vs. Customer-Owned PV-DSM System: 16.3 Kw (Credited Capacity) Dispatchable System for Delmarva Power & Light

	Benefits ($)		Costs ($)	
Utility-Owned and Operated[a]				
Avoided Costs[b]	$ 45,610		Capital Costs	$ 95,740
Tax Savings	50,330		Carrying Charges	25,920
			O&M Costs	23,510
Total	$ 95,940			$145,170
Benefit-Cost Ratio		0.66 (0.48)[c]		
Customer-Owned and Operated[d]				
Energy Savings	$ 9,520		Capital Costs	$ 95,740
Demand Savings	18,230		O&M Costs	15,300
Tax Savings	56,980			
Total	$ 84,730			$111,040
Benefit-Cost Ratio		0.76		

[a]The utility benefits and costs are discounted at the rate of 7.99%.
[b]Avoided costs are based on a 10% capacity factor.
[c]In the case of a Total Resource Cost (TRC) test in which tax savings ($50,340) are deducted against costs instead of treated as benefits, the ratio decreases to 0.48.
[d]Customer benefits and costs are discounted at the rate of 12%.
Source: Center for Energy and Environmental Policy, University of Delaware.

Utility-Customer Partnership

To speed penetration of PV into the DSM market, a utility-customer partnership may be needed. In such an arrangement, a utility, or its unregulated subsidiary, would act as the financing agent because most large commercial customers would be unwilling to devote a large amount of upfront cash to purchase a

*The benefit-cost ratio reported here includes tax benefits. Utilities and regulators commonly use a Total Resource Cost (TRC) test to evaluate the benefits and costs of DSM. This test excludes tax credits and subtracts tax deductions (e.g., for depreciation) from capital costs. If the TRC approach is used, the benefit-cost ratio decreases from 66 to 48 percent ($45,690 in NPV benefits versus $95,690 in NPV net costs). Since unregulated businesses often treat tax savings and credits as benefits in benefit-cost analyses of capital-intensive investments, we believe 66 percent is the more useful value for comparison purposes. Some analysts have called for a revision of the TRC calculation in the case of customer-sited renewable energy technology so that tax savings can be recognized as benefits (see Howard Wenger, Tom Hoff and Richard Perez. "Photovoltaics as a Demand-Side Management Option: Benefits of a Utility-Customer Partnership". Presented at the World Energy Engineering Congress. Atlanta, Georgia, October 1992).

Table 2
Utility-Customer Partnership Options:[a] Dispatchable PV-DSM for Delmarva Power & Light

Benefits ($)		Costs ($)	
Without Nontraditional Benefits (16.3 Kw Credited Peak-Shaving Capacity)			
Bill Savings	$ 40,250	Capital Costs	$ 95,740
Tax Benefits		O&M Costs	23,510
and Deductions	63,120	Loan Servicing Costs	2,900
Total	$103,370		$122,150
Benefit-Cost Ratio	0.85		
With Nontraditional Benefits (16.3 Kw Credited Peak-Shaving Capacity)[b]			
Bill Savings	$ 40,250	Capital Costs	$ 95,740
Environmental Benefit	300	O&M Costs	23,510
T&D Benefits	26,120	Loan Servicing Costs	2,900
Tax Benefits			
and Deductions	63,120		
Total	$129,790		$122,150
Benefit-Cost Ratio	1.06		
With Efficiency Improvement and Cost Reduction (25.6 Kw Credited Peak-Shaving Capacity)[c]			
Bill Savings	$ 63,360	Capital Costs	$ 73,520
Tax Benefits		O&M Costs	32,000
and Deductions	43,810	Loan Servicing Costs	2,210
Total	$107,170		$107,730
Benefit-Cost Ratio	1.00		

[a]Benefits and costs are discounted at the rate of 7.99%, assuming that the utility, or its subsidiary, would provide financing at the same rate. The loan rate now becomes the customer's opportunity cost of capital, thereby becoming the customer's appropriate discount rate.
[b]In the TRC test, the B/C ratio is also greater than one if tax savings are included as benefits.
[c]Improved conversion efficiency (from 10 percent to 15 percent) and cost reductions for modules allow the purchase of a larger PV array (from 10 Kw to 15.5 Kw). The system's credited peak-shaving capacity increases from 16.3 Kw to 25.6 Kw, which requires additional storage (84 Kwh, instead of 50 Kwh). O&M expenses are higher due to the increased storage needs.

PV-DSM system. Furthermore, a utility's cost of capital is likely to be significantly lower than that of its commercial customers. Thus, commercial customers investing in a PV-DSM system would have access to the necessary funds, at a lower interest rate.

Commercial customers would then use their bill savings and tax benefits to repay the utility's loan. This arrangement is similar to the shared-savings programs currently used by utilities to fund investments to improve end-use efficiency. Under these programs, the customer contracts with the utility, or energy service company (ESCo), and forfeits a portion of its bill savings to pay for the investment.

Table 2 illustrates three economic scenarios based on the proposed partnership arrangement. In the first, we assumed that the utility would make funds available to the customer to invest in the PV-DSM system. The customer would be charged an interest rate equal to the utility's after-tax weighted cost of capital. In addition, the utility would be paid 3 percent of the loan to cover any administrative expenses that the utility might incur in making the loan. The customer would use its electric bill savings and tax benefits to repay the loan. In this partnership case, the benefits of the system cover 85 percent of its costs—9 percentage points higher than the customer-owned and operated system. This first calculation was based solely on traditional benefits.

If a system is sited in an area with a particularly high cost of service, the utility may receive nontraditional benefits, as the second scenario indicates. Because the magnitude of distributed benefits is extremely site-specific, we chose a conservative value of $150 per kilowatt-year, based on results from five case-studies that estimated the value of distributed benefits for PV technologies. The full 16.3-Kw credited capacity of the system was used to determine total distributed benefits over the 25-year life of the system. In addition, an environmental benefit was calculated by using the value of sulfur dioxide allowances being traded under the 1990 Clean Air Act Amendments ($250/ton). We assumed that the utility would offer these nontraditional benefits to the customer as a rebate for investing in PV-DSM, with the customer using the rebate to reduce the amount of money that it borrowed from the utility. Under this arrangement, PV-DSM would be cost-effective (benefit/cost ratio equal to 1.06) for commercial customers located in the DP&L service territory.

The third scenario considers the impacts of technological improvements and PV-system cost reductions on the economic viability of PV-DSM. In particular, the PV AC-conversion efficiency was assumed to increase from 10 to 15 percent, while the cost of the PV array would decline by one-third (from $85,000 to $57,000, storage not included). The efficiency gain would result in more peak-shaving capacity from the 105 m^2 PV array assumed in our analysis (the system would now have a credited peak-shaving capacity of 25.6 Kw, and a rated capacity of 15.75 Kw). Under these assumptions, PV-DSM would be cost-effective even without a utility contribution.

Our analysis suggests that PV-DSM is technically feasible and near commercial viability. In the case of a dispatchable PV-DSM application in a strategic site, the estimated benefits of a utility-customer partnership can equal 100 percent or more of the current costs for an installed system. Through increased module efficiency and cost reductions in major PV system components, dispatchable PV systems could emerge as cost-effective DSM options for commercial buildings, without the need for a utility contribution. The continued movement toward real-time electricity pricing will also enhance the competitiveness of the PV-DSM application discussed here.

Although the analysis presented here is based on one utility's experience, the results can be readily transferred to other utilities located across the country. Perez *et al.* (1993) have calculated the Effective Load Carrying Capability (ELCC), a statistical measure of effective capacity, for PV systems located in numerous utility service territories across the country. They measured an ELCC of 49 percent for a fixed-tilt PV array located in DP&L's service territory, but found that several utilities located in other regions of the country have even higher ELCCs. For example, Consolidated Edison Co. and Pacific Gas & Electric Co. have ELCCs (for fixed-tilt PV arrays) of 68 and 64 percent, respectively. Thus, PV-DSM systems located in the service territories of these utilities would probably perform even better than systems located in DP&L's service territory.

In addition, since DP&L's demand and energy charges for commercial customers are near the average of the utility industry, the economics for customer-owned systems would be even more favorable for utilities with above-average demand and energy charges. Furthermore, DP&L's avoided costs are fairly representative of utilities that will not experience capacity constraints in the near future. ▼

PV-DSM Versus Batteries Only

An alternative to PV-DSM that can provide dispatchable peak shaving capacity is a battery-only system, which would use offpeak 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. An NPV analysis showed that for a low demand-charge scenario ($100/Kw-year demand charge and 3.0¢/Kwh energy rate) the battery-only system was more economical; for an intermediate demand-charge scenario ($160/Kw-year demand charge and 3.5¢/Kwh energy rate) the PV-DSM system was slightly more economical; and for the high demand-charge scenario ($200/Kw-year demand charge and 6.0¢/Kwh energy rate), the PV-DSM system would be preferred. The intermediate demand-charge scenario is representative of most summer-peaking utilities in the United States.

There are economic and other advantages of a PV-DSM system that go beyond direct benefit-cost comparisons. For example, compared to a battery-only system, a dispatchable PV system avoids the risk of higher fuel costs. Because it is a zero-emission technology, it also avoids the costs associated with future air-quality regulations. And, because the PV array, as well as its battery unit, supply energy at the time of dispatch, the size of the battery bank is considerably smaller than for the battery-only option, thereby reducing maintenance requirements.

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